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## ONTARIO ENERGY BOARD

**IN THE MATTER** OF *the Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 ("**Act**");

**AND IN THE MATTER OF** an Application by Upper Canada Transmission, Inc. operating as NextBridge Infrastructure, LP for an Order or Orders pursuant to section 78 of the Act approving rates and other charges for transmission of electricity.

# APPLICATION

### The Applicant and The Orders Requested

1. The applicant ("**Applicant**"), Upper Canada Transmission, Inc. ("**UCT**") was designated by Decision and Order dated August 7, 2013 (EB-2011-0140) as the transmitter for the development of new electricity transmission facilities running between outside Thunder Bay to Wawa, Ontario, commonly referred to as the "East-West Tie line".

2. UCT brings this application ("**Application**") in its capacity as the general partner, acting for and on behalf of the limited partnership, NextBridge Infrastructure, LP ("**NextBridge**"). NextBridge is a New Brunswick corporation established for the purpose of developing, owning, and operating the East-West Tie line.

3. By Decision and Order dated February 11, 2019 (EB-2017-0182), UCT was granted leave to construct the East-West Tie line. UCT's transmission licence was accordingly amended to require it to:

    - *Develop, seek approvals in respect of, and proceed with immediacy to construct, expand, or reinforce the new transmission line between Wawa and Thunder Bay*

- *Provide such reporting to the OEB and the IESO as considered appropriate, including, at a minimum, regular reports on construction progress, budget, timing, and risks of the project*

4. This is an Application for approval of a Revenue Cap Index ("**RCI**") framework for the period April 1, 2022 to December 31, 2031.

5. The base revenue requirement for the period April 1, 2022 to December 31, 2022 is $41.8 million. This is a prorated calculation based on an annual revenue requirement of $55.7 million for a full year cost of service for the period April 1, 2022 to March 31, 2023.

6. The proposed RCI mechanism is an annual rate adjustment of 2% to take effect on January 1st in each year of the term for the period January 1, 2023 to December 31, 2031.

7. The base revenue requirement and rate adjustments are proposed to be implemented through the OEB's approved Uniform Transmission Rates ("**UTR**") for the Network pool.

8. UCT hereby applies to the Ontario Energy Board ("**OEB**") pursuant to section 78 of the Act, as amended, for an order approving its proposed transmission rates and related orders approving the:

   - recovery of $31.24 million in development costs approved by Decision and Order dated December 20, 2018 (EB-2017-0182);
   - recovery of $5.331 million of pre-July 31, 2017 costs identified in Decision and Order dated December 20, 2018 (EB-2017-0182) as eligible for consideration as construction costs (referred to as Phase Shift Costs) and detailed as follows:

| Cost category | $ Millions |
|---|---|
| **Extended in-service date** | |
| Environmental assessment review participation | $0.46 |
| Land optioning negotiations | $1.44 |
| **Unbudgeted at designation** | |
| Land acquisition negotiations | $0.02 |
| Economic participation | $3.41 |
| **Total** | **$5.33** |

- recovery of $737 million of construction costs also tracked in the CWIP Account 2055 ("**CWIP Account**") established pursuant to Decision and Order dated February 11, 2019 (EB-2017-0182);
- recovery of $1.2 million in spares;
- inclusion in the UTR for the Network pool to allow for the recovery of NextBridge's proposed rates revenue requirement for 2022, for nine months of service beginning on April 1, 2022, as described in Exhibit A, Tab 3, Schedule 1;
- use of a Custom Incentive Regulation Model as a framework to annually adjust transmission rates for the period effective January 1, 2023 to December 31, 2031 as described in Exhibit A, Tab 3, Schedule 1, and the related rates, charges, and conditions of services;
- establishment of the accounting orders for a construction cost variance account ("**CCVA**") to be made effective the date of the filing of this Application, as described in Exhibit H, Tab 1, Schedule 1;
- establishment of the accounting orders for a debt rate variance account ("**DRVA**") to track and effectuate the one-time update to the cost of long-term debt in 2023

to reflect the actual cost of long-term debt associated with the financing of East-West Tie line, as described in Exhibit H, Tab 1, Schedule 1;

- establishment of the accounting orders for taxes or payments in lieu of taxes variance account ("**PILsVA**") effective April 1, 2022, as described in Exhibit H, Tab 1, Schedule 1;
- establishment of the accounting orders for a revenue differential variance account ("**RDVA**") effective April 1, 2022, as described in Exhibit H, Tab 1, Schedule 1;
- establishment of a Z-factor account if material costs are incurred for unforeseen events for reasons beyond the company's control that occur during the IR Term, as described in Exhibit H; and
- other items or amounts that may be requested by the applicant in the course of this proceeding, and as may be granted by the OEB.

9. This Application is prepared in accordance with the OEB's *Filing Requirements for Electricity Transmission Applications* last revised February 11, 2016 ("**Transmission Filing Requirements**"), and with the OEB's *Filing Requirements for Electricity Distribution Rate Applications* last revised May 14, 2020 ("**Distribution Filing Requirements**") as applicable.

10. The written evidence filed with the OEB may be amended from time-to-time prior to the OEB's final decision in this Application.

11. The Applicant may request meetings with OEB staff and interveners in an attempt to identify, and reach agreements to settle, issues arising out of this Application.

**Notice and Form of Hearing Requested**

12. The persons affected by this application are the transmission ratepayers served under the UTR. It is impractical to set out their names and addresses because they are too

numerous. Notice of this Application should be published so as to reach the largest number of customers across Ontario in an efficient manner.

13. The Application may be viewed on the internet at www.nextbridge.ca.

14. The Applicant requests that this Application be heard by way of a written hearing.

**Proposed Effective Date**

15. The Applicant requests that the OEB's rate orders be effective one day after the East-West Tie line comes into service, which is scheduled to occur on March 31, 2022. To address the possibility that the requested rate orders cannot be made effective by that time, the Applicant hereby requests an interim order or orders to implement transmission rates and charges requested herein effective on an interim basis as of April 1, 2022, and establishing an account to recover any differences between the interim rates and the final rates determined by the OEB's decision and order in this Application.

16. NextBridge requests that a copy of all documents filed with the OEB by OEB staff and each party to this Application be served on the Applicant and the Applicant's counsel as follows:

**A. The Applicant:**

Mr. Brian J. Murphy

Managing Attorney, NextEra Energy Resources, LLC

Ms. Jennifer Tidmarsh

President, NextEra Energy Transmission Canada, LLC

Address for personal service:

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**B. The Applicant's counsel:**

Mr. George Vegh, Reena Goyal and Sam Rogers

Ms. Reena Goyal

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DATED at Toronto, Ontario, this 4th day of November, 2020

BY UPPER CANADA TRANSMISSION INC. DOING BUSINESS AS NEXTBRIDGE INFRASTRUCTURE, LP

By its counsel,

ORIGINAL SIGNED BY GEORGE VEGH

George Vegh

# CERTIFICATE OF EVIDENCE

Upper Canada Transmission Inc.,
Doing business as NextBridge Infrastructure, LP

TO: ONTARIO ENERGY BOARD

The undersigned, Jennifer Tidmarsh, hereby certifies on behalf of NextBridge that:

1. I am the Project Director for NextBridge;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised on February 11, 2016); and
3. The evidence submitted in support of NextBridge's revenue requirement Application EB-2020-0150 filed with the Ontario Energy Board is accurate, consistent, and complete to the best of my knowledge.

DATED: November 4th, 2020

ORIGINAL SIGNED BY JENNIFER TIDMARSH

Jennifer Tidmarsh for NextBridge Infrastructure, LP

# COMPLIANCE WITH TRANSMISSION FILING REQUIREMENTS

1. NextBridge has prepared this Application in alignment with the Transmission Filing Requirements. To assist the OEB in its review of the Application, NextBridge has prepared a checklist of the Transmission Filing Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1 to this Exhibit.

2. In preparing this Application, NextBridge followed the expectations of a RCI Application provided in the Transmission Filing Requirements:

   - IR Term: 9 years 9 months (9 months plus 9 years)
   - Index for the annual rate adjustment: the proposed RCI used the OEB-approved inflation factor and a 0% productivity factor as outlined in Exhibit E, Tab 1, Schedule 1.
   - Benchmarking: Independent third-party Charles River Associates ("**CRA**") was engaged by NextBridge to prepare a benchmarking study of transmission projects comparable to that of the East-West Tie line. A copy of the CRA report can be found at Exhibit B, Tab1, Schedule 7, Attachment 1.
   - Performance Metrics: NextBridge proposes to track its performance utilizing a set of outcome measures as documented in Exhibit D, Tab 1, Schedule 1 to ensure that NextBridge meets its 10-year business plan. The proposed metrics align with the OEB's Renewed Regulatory Framework for Electricity ("**RRFE**") outcomes of operational effectiveness, financial performance, and public policy responsiveness.
   - Protecting customers: Exhibit G outlines NextBridge's proposal to not seek any capital expenditures as part of its revenue requirement. This is NextBridge's proposal to mitigate any potential for significant earnings due to planned capital expenditures.

**Exceptions to the Transmission Filing Requirements**

3. Given that the East-West Tie line is a single transmission line asset and has a limited role in the transmission of electricity (*i.e.*, no delivery points, no TS), the following Chapter 2 Transmission Filing Requirements are not applicable:

*Working capital allowance*

4. In Bruce to Milton's ("**B2M**") transmission rates application (EB-2015-0026), it was established that there is no need for a working capital allowance given that timing of the payments and revenue could be organized by the general partner to effectively ameliorate any meaningful lead or lag on those cash flows. The same situation applies for NextBridge and, therefore, these is no request for a working capital allowance to be included in rate base.

*Economic overview/load forecast*

5. NextBridge's asset base will consist of 450 km of new double circuit 230 kV overhead electricity transmission line on a new ROW between Thunder Bay to Wawa in Northwestern Ontario with no delivery points. Hence NextBridge has no discrete, incremental load determinants to include in the UTRs forecast. An economic overview and consideration of capacity needs associated with East-West Tie line were studied and confirmed by the Independent Electricity System Operator ("**IESO**"). The three most recent IESO assessments dated December 15, 2015, December 1, 2017 and June 29, 2018 are attached as Exhibit B, Tab 1, Schedule 5, Attachment 1 -3, respectively.

6. The only rate pool applicable for NextBridge assets is the "Network" pool. Therefore, no cost allocation methodology is presented in this Application.

*Other revenue*

7. NextBridge has no external revenue sources; the only revenue applicable to NextBridge is the revenue requirement from owning and maintaining the East-West Tie line.

*Employee compensation*

8. NextBridge will have no employees. OM&A will either be provided under a service level agreement with Hydro One Networks ("**HONI**" or "**Hydro One**") or provided by its partners NextEra Energy Transmission, LLC ("**NEET**") through its partner affiliate agreement ("**NEET Agreement**") as explained in Exhibit B, Tab 1, Schedule 4. Both agreements are being finalized and will be filed as an update to the Application when available.

# FILING REQUIREMENTS CHECKLIST

# Transmission Filing Requirements Checklist

## NextBridge Infrastruture

**Date: November 2020**

| Filing Requirement Page # Reference | | Yes or N/A | Evidence Reference, Notes |
|---|---|---|---|
| **GENERAL REQUIREMENTS** | | | |
| Ch 1, p 2 | Certification that the evidence filed is accurate, consistent and complete | Yes | Exhibit A, Tab, 2, Schedule 2, Attachment 1 |
| 3 | Confidential Information - Practice Direction has been followed | N/A | |
| Ch 2, p 4 | Provide Chapter 2 appendices that are applicable to transmission applications<br>*Appendices that are not applicable:*<br>*App.2-G: Service Reliability Indicators*<br>*App.2-H: Other Operating Revenue*<br>*App.2-I: Load Forecast CDM Adjustment Workform*<br>*App.2-IA: Load Forecast Data Instructions*<br>*App.2-IB: Actual and Forecast Load and Customer Data*<br>*App.2-JC: OM&A Programs Table*<br>*App.2-K: Employee Costs*<br>*App.2-N: Shared Services and Corporate Cost Allocation* | Yes | ################################################## |
| 4 | Written direct evidence is to be included before data schedules | Yes | |
| 4 | Average of the opening and closing fiscal year balances must be used for items in rate base | Yes | Exhibit C, Tab 1, Schedule 1 |
| 4 | Total capitalization (debt and equity) must equate to total rate base | Yes | Exhibit G, Tab 1, Schedule 1 and Exhibit C, Tab 1, Schedule 1 |
| 4 | *Historcial information not applicable:* Data for the following years, at a minimum, must be provided: Test year = prospective rate year; Bridge year = current year; Four most recent historical years; Most recent OEB-approved test year | N/A | |
| 4 | *Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 4 | Documents are to be provided in bookmarked and text-searchable Adobe PDF format | Yes | |
| 4 | Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical | Yes | |
| 6 | Materiality threshold | Yes | Exhibit A, Tab 3, Schedule 1 |
| 6 | State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing | Yes | Exhibit A, Tab 5, Schedule 2 |

| EXHIBIT A - ADMINISTRATIVE DOCUMENTS | | | |
|---|---|---|---|
| *Executive Summary* | | | |
| Ch 2, p 8 | Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives<br>*Past performance not applicable* | Yes | Exhibit B, Tab 1, Schedule 3 |
| 8 | Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE *Not applicable: customer feedback reflected in the transmitter's objectives* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 8 | Revenue Requirement - request, changes from previous revenue requirement and drivers of change<br>*Changes not applicable, no previous filings* | N/A | |
| 8 | Budgeting Assumptions - Economic overview<br>*Limited to capital expenditures* | Yes | Exhibit A, Tab 3, Schedule 1<br>Exhibit B, Tab 1, Schedule 5 |
| 8 | Load Forecast - Load growth and forecast methods<br>*Not applicable* | N/A | Exhibit A, Tab 3, Schedule 1 |
| 9 | TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved<br>*Changes not applicable, no previous filings* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Rate Base - Request for test years and change from last OEB approved<br>*Changes not applicable, no previous filings* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Performance and Reporting - Proposed scorecard<br>Reporting limited to the 5 metrics in the EB-2015-0026 Decision | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | OM&A - Request for test years; changes from last OEB approved and drivers of change<br>*Changes not applicable, no previous filings* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Cost Allocation & Rate Design - Summary of how costs are allocated to rate pools | Yes | Exhibit A, Tab 3, Schedule 1 |
| 10 | Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts | Yes | Exhibit A, Tab 3, Schedule 1 |
| 10 | Bill Impacts - Summary of impacts at wholesale level and for typical retail customers | Yes | Exhibit A, Tab 3, Schedule 1 |
| *Customer Engagement* | *Generally, not applicable: NextBridge has no customers, but alternative information provided* | | |
| Ch 2, p 10 | Customer engagement process and activities | Yes | Exhibit A, Tab 4, Schedule 1 |
| 10 | Customer needs including end-use load customers and generator customers | Yes | Exhibit B, Tab 1, Schedule 3<br>Exhibit B, Tab 1, Schedule 4 |
| 10 | How the application responds to customer needs | Yes | Exhibit B, Tab 1, Schedule 3 |
| 10 | Customer satisfaction surveys | N/A | |
| 10 | Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence | N/A | |
| 11 | Responses to letters of comment - *Generally, not appliable; have included stakeholder matrials and community* | Yes | Exhibit A, Tab 4, Schedule 1 |
| *Financial Information* | | | |
| Ch 2, p 11 | Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals) | Yes | Exhibit A, Tab 5, Schedule 1, Attachments 1 & 2 |
| 11 | Detailed reconciliation of AFS with regulatory financial results | N/A | |
| 11 | Annual Report and MD&A for most recent year of parent company | Yes | Exhibit A, Tab 5, Schedule 1, Attachments 3, 4 & 5 |
| 11 | Rating Agency Reports<br>*Not applicable* | N/A | Exhibit A, Tab 5, Schedule 3 |
| 11 | Prospectuses & information circulars for recent and planned public offerings<br>*Not applicable* | N/A | Exhibit A, Tab 5, Schedule 1 |

| | | | |
|---|---|---|---|
| *Administration* | | | |
| Ch 2, p 11 | Table of Contents | Yes | Exhibit A, Tab 1, Schedule 1 |
| 11 | Statement identifying customers materially affected by the application | N/A | |
| 12 | Internet address for viewing of application | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Primary contact information (name, address, phone, fax, email) | Yes | Exhibit A, Tab 10, Schedule 1 |
| 12 | Identification of legal representation | Yes | Exhibit A, Tab 10, Schedule 1 |
| 12 | Requested effective date | Yes | Exhibit A, Tab 8, Schedule 2 |
| 12 | Bill impacts for typical Ontario residential customer an Ontario General Service customer | Yes | Exhibit A, Tab 3, Schedule 1 |
| 12 | Form of hearing requested (written or oral) | Yes | Exhibit A, Tab 8, Schedule 1 |
| 12 | List of approvals requested including accounting orders | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Proposed length of the term and proposed method for establishing revenue requirement for each year of the term | Yes | Exhibit A, Tab 3, Schedule 1 |
| 12 | Changes in tax status<br>*Changes not applicable, no previous filings* | N/A | |
| 12 | Existing Accounting Orders | Yes | Exhibit A, Tab 5, Schedule 2 |
| 12 | Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility. | Yes | Exhibit A, Tab 7, Schedule 1 |
| 12 | Corporate and utility organizational structure, planned changes, rationale for changes and cost impact | Yes | Exhibit A, Tab 6, Schedule 1 |
| 13 | The Accounting Standard used and when it was adopted | Yes | Exhibit A, Tab 5, Schedule 2 |
| 13 | Deviations from filing requirements, if any | Yes | Exhibit A, Tab 2, Schedule 3 |
| 13 | Changes to methodologies used in previous applications<br>*Changes not applicable, no previous filings* | N/A | |
| 13 | Confirmation that accounting treatment is segregated for non-regulated business<br>*NextBridge has no non-regulated business* | N/A | |
| 13 | Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application | Yes | Exhibit A, Tab 8, Schedule 4 |
| **EXHIBIT 2 - Transmission System Plan** | | | |
| *General* | | | |
| Ch 2, p 13 | Refer to Chapter 5 of the Distribution Filing Requirements | Yes | Exhibit B |
| 13 | The strategic plan for the utility and investment strategy | Yes | Exhibit B, Tab 1, Schedule 3 |
| 13 | The longer term economic and planning assumptions | Yes | Exhibit B, Tab 1, Schedule 5 |
| 13 | The asset management plan | Yes | Exhibit B, Tab 1, Schedule 4 |
| 13 | A description of how investments are prioritized and selected | Yes | Exhibit B, Tab 1, Schedule 4 |
| 13 | A discussion of transmission investments identified in the regional planning process | Yes | Exhibit B, Tab 1, Schedule 5 |
| 13 | Highlights of recent and proposed investments and their fit with the strategic plan | Yes | Exhibit B, Tab 1, Schedule 4 |
| 13 | A description of how the needs of customers and overall system planning policy objectives are being reflected | Yes | Exhibit B, Tab 1, Schedule 3 |
| 13 | Commitments stemming from the Long Term Energy Plan or the Conservation First policy, and consideration for the OEB's statutory objectives, including facilitating a smart grid and the connection of renewables | Yes | Exhibit B, Tab 1, Schedule 3 |
| *Asset Management Plan* | | | |
| Ch 2, p 14 | Asset management policy, strategy and objectives | Yes | Exhibit B, Tab 1, Schedule 4 |
| 14 | Inventory and assessment of the condition of capital assets (by class and inclusion in BES), how this informs plan for capital expenditures and maintenance expenditures | Yes | Exhibit B, Tab 1, Schedule 4 |
| 14 | Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied - *Not applicable* | N/A | |
| *Regional Considerations* | | | |
| Ch 2, p 14 | Regional planning process demonstrating that regional considerations have been considered and addressed | Yes | Exhibit B, Tab 1, Schedule 5 |
| 14 | Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP | Yes | Exhibit B, Tab 1, Schedule 5 |
| 14 | Identify investments spanning more than one region - *Not applicable* | N/A | |
| *Coordinated Planning with Third Parties* | | | |
| Ch 2, p 15 | Description of the consultation including: the purpose of the consultation; whether the transmitter initiated the consultation or was an invitee; participants in the consultation; deliverables and impact on plan | Yes | Exhibit A, Tab 4, Schedule 1; Exhibit B, Tab 1, Schedule 5 |

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| *Capital Expenditures* | | | |
| Ch 2, p 16 | Summary of capital expenditures over the past five historical years including the bridge year and five future years including the test year(s), showing treatment of contributed capital and additions and deductions from Construction Work in Progress<br>*Historical not applicable, new entrant* | Yes | Exhibit B, Tab 1, Schedule 6 |
| 16 | Material Investments - For projects and programs:<br>- a description of the need, scope and purpose of the project or program<br>- customer attachments<br>- load and capital costs<br>- cost-benefit analysis<br>- identify where "leave to construct" required or project is necessary to comply with a licence condition | Yes | Exhibit B, Tab 1, Schedule 6 |
| 16 | Drivers of capital expenditure increases for the test year(s) | Yes | Exhibit B, Tab 1, Schedule 6 |
| 16 | The basis for the estimated budget for the project or program | Yes | Exhibit B, Tab 1, Schedule 6 |
| 16 | For the balance of capital expenditures, describe components of capital expenditure and provide a reconciliation of capital components to total capital budget | Yes | Exhibit B, Tab 1, Schedule 6 |
| 17 | Written explanation of capital expenditure variances<br>*Variances not applicable, no prior filings* | N/A | |
| 17 | The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year | Yes | Exhibit B, Tab 1, Schedule 6 |
| 17 | Cost benchmarking studies or utility cost comparisons | Yes | Exhibit B, Tab 1, Schedule 7 |
| 17 | Continuous improvement or efficiency gains, how they will be achieved and benefit customers | Yes | Exhibit B, Tab 1, Schedule 6 |
| 17 | A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income | Yes | Exhibit B, Tab 1, Schedule 6 |
| **EXHIBIT 3 - Rate Base** | | | |
| *Overview* | | | |
| Ch 2, p 17 | Opening and closing balances and the averages thereof gross assets and accumulated depreciation<br>Rate base shall include an allowance for working capital<br>Rate base must be supported by historical actuals, bridge year and test years (*not applicable historical and bridge years)* | Yes | Exhibit C, Tab 1, Schedule 1 |
| 18 | Continuity statements (year end balance, including interest during construction and overheads).<br>Explanation for any restatement (e.g. due to change in accounting standards)<br>Year over year variance analysis; explanation where variance greater than materiality threshold<br>Hist. OEB-Approved vs Hist. Actual<br>Hist. Act. vs. preceding Hist. Act.<br>Hist. Act. vs. Bridge<br>Bridge vs. Testn *(not applicable historical and bridge years)* | N/A | |
| 18 | Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation | Yes | Exhibit C, Tab 1, Schedule 1 |
| 19 | Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format. | Yes | Exhibit C, Tab 1, Schedule 1 |
| *Gross Assets - PP&E and Accumulated Depreciation* | | | |
| Ch 2, p 19 | Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses | Yes | Exhibit C, Tab 2, Schedule 1<br>Exhibit C, Tab 4, Schedule 1 |
| 19 | Detailed breakdown by major plant account for each functionalized plant item; For the test year(s), each plant item must be accompanied by a description. | Yes | Exhibit C, Tab 2, Schedule 1<br>Exhibit C, Tab 3, Schedule 1<br>Exhibit C, Tab 4, Schedule 1 |
| 19 | Detailed breakdown of the in-service capital additions for the test year(s) | Yes | Exhibit C, Tab 2, Schedule 1<br>Exhibit C, Tab 3, Schedule 1<br>Exhibit C, Tab 4, Schedule 1 |
| 19 | Continuity statements must reconcile to calculated depreciation expenses and presented by asset account | Yes | |
| *Allowance for Working Capital* | *Not Applicable: NexBridge requires no working capital* | | |
| Ch 2, p 19 | Working Capital - Lead/Lag Study | N/A | |
| 19 | Lead/Lag Study - leads and lags measured in days, dollar-weighted | N/A | |
| 19 | For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources. | N/A | |

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| *Customer Connection and Cost Recovery Agreements* | | | |
| Ch 2, p 20 | The transmitter should show customer contribution amounts separately as an offset to rate base.<br>*Not applicable to offset rate base* | Yes | Exhibit C, Tab 6, Schedule 1 |
| 20 | Agreements reviewed on reaching a fifth anniversary and aggregated estimate of total expected true-up contributions and proceeds from bypass agreements | N/A | |
| 20 | Financial and regulatory accounting treatment of true-up proceeds. | N/A | |
| *Capitalization Policy* | | | |
| Ch 2, p 20 | Capitalization policy, including changes since the last revenue requirement application<br>*Not applicable* | N/A | Exhibit C, Tab 7, Schedule 1 |
| 20 | Overhead costs on self-constructed assets<br>*Not applicable* | N/A | Exhibit C, Tab 7, Schedule 1 |
| 20 | Identification of burden rates and burden rates prior to changes, if any<br>*Not applicable* | N/A | Exhibit C, Tab 7, Schedule 1 |
| *Capital Module* | | | |
| Ch 2, p 21 | Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the Transmission System Plan; intended to come into service during the index period; Involve costs that the transmitter cannot manage through the revenue established through the index<br>*Not applicable* | N/A | Exhibit C, Tab 8, Schedule 1 |
| 21 | The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment. | N/A | |
| **EXHIBIT 4 - Service Quality and Reliability Performance and Reporting** | | | |
| *Proposed Scorecard* | *Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision* | | |
| 21 | Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant measures | Yes | Exhibit D, Tab 1, Schedule 1 |
| *Reliability Performance* | *Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision* | | |
| 22 | Reliability performance measures: transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability | Yes | Exhibit D, Tab 1, Schedule 1 |
| 22 | Address performance standards for transmitters as set out in Chapter 4 of the TSC. | Yes | Exhibit D, Tab 1, Schedule 1 |
| 22 | Compare system performance with other systems both nationally and internationally | N/A | |
| *Compliance Matters* | | | |
| 22 | Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance<br>*Not applicable* | N/A | Exhibit D, Tab 2, Schedule 1 |
| **EXHIBIT 5 - Operating Revenue** | | | Exhibit E, Tab 1, Schedule 1 |
| *Load and Revenue Forecasts* | *Not applicable: NextBridge has no load forecast* | | |
| 23 | Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts | N/A | |
| 23 | Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses | N/A | |
| 23 | Detailed CDM forecast, with impact of CDM shown on the load forecast for each of the three rate pools. The applicant must also indicate how the forecast reflects IESO CDM forecasts and targets in the load forecast | N/A | |
| 23 | Impact of forecast embedded generation on the transmission system load accounted for | N/A | |

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| *Accuracy of Load Forecast and Variance Analyses* | *Not applicable: NextBridge has no load forecast* | | Exhibit E, Tab 2, Schedule 1 |
| 23 | Demonstrate five year historical accuracy by providing schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for:<br>- Historical OEB-approved;<br>- Historical actual for the past 5 years;<br>- Historical actual for the past 5 years – weather normalized;<br>- Bridge year;<br>- Bridge year – weather normalized;<br>- Test year | N/A | |
| | *Not applicable: NextBridge has no load forecast* | | |
| 24 | Analyses and discussion for volumes, revenues, customer/connections count and total system load:<br>- Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences;<br>- Historical OEB-approved vs. historical actual;<br>- Historical OEB-approved vs. historical actual – weather normalized;<br>- Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years);<br>- Historical actual – weather normalized vs. bridge year – weather-normalized;<br>- Bridge year – weather-normalized vs. test year(s) | N/A | |
| 24 | All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format | N/A | |
| *Other Revenue* | *Not applicable: NextBridge has no other revenue* | | Exhibit E, Tab 3, Schedule 1 |
| 24 | Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons | N/A | |
| 24 | How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges | N/A | |
| 24 | Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs | N/A | |
| 24 | Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue. | N/A | |
| **EXHIBIT 6 - Operating Cost** | | | |
| *Overview* | | | |
| Ch 2, p 25 | Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes, benchmarking, description of the continuous improvement or efficiency gains | Yes | Exhibit F, Tab 1, Schedules 1 |
| *Summary and Cost Driver Tables* | | | |
| Ch 2, p 26 | Summary of recoverable OM&A expenses | Yes | Exhibit F, Tab 4, Schedules 1 |
| 26 | Recoverable OM&A cost drivers | Yes | Exhibit F, Tab 4, Schedules 2 |
| 26 | Change in OM&A in test year attributable to a change in capitalized overhead | N/A | |
| 26 | OM&A variance analysis for test year with respect to bridge and historical years *(not applicable historical and bridge years)* | N/A | |
| *Program Delivery Costs with Variance Analysis* | | | |
| **Ch 2, p 26** | O&M Costs for:<br>- employee compensation<br>- shared services<br>- corporate cost allocation<br>- purchase of non-affiliate services<br>- one-time costs<br>- OEB costs<br>- Charitable and political donations | Yes | Exhibit F, Tabs 5 - 10, Schedules 1 |
| *Employee Compensation* | *Not applicable* | | Exhibit F, Tab 5, Schedule 1 |
| Ch 2, p 26 | Employee complement, compensation and benefits | N/A | |
| 26 - 27 | Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes:<br>- year over year variances<br>- basis for performance pay, eligible employee groups, goals, measures and review process for pay-for-performance plans<br>- benchmarking studies | N/A | |
| 27 | Employee benefit programs including pensions | N/A | |
| 27 | Most recent actuarial reports | N/A | |

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| *Shared Services and Corporate Cost Allocation* | | | |
| Ch 2, p 27 | Identification of shared services | Yes | Exhibit F, Tab 5, Schedule 1 |
| 27 | Allocation methodology for corporate and shared services | Yes | Exhibit F, Tab 5, Schedule 1 |
| 28 | Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section | N/A | |
| 28 | Variance analysis - test year vs last OEB approved and most recent actual | N/A | |
| 28 | Identification of any Board of Director costs for affiliates included in LDC costs | N/A | |
| *Purchase of Non-Affiliate Services* | | | |
| 28 | Procurement Policy | Yes | Exhibit F, Tab 5, Schedule 1<br>Exhibit C, Tab 2, Schedule 4, Attachment 1 |
| 28 | Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product and describe how vendor was selected | N/A | |
| *One-time Costs* | *Not applicable* | | |
| 28 | One-time costs - historical, bridge, test year costs.<br>Explanation of cost recovery in test years.<br>Costs in the test years will not result in an over recovery in future years. | N/A | Exhibit F, Tab 8, Schedule 1 |
| *Regulatory Costs* | | | |
| 28 | Regulatory costs - breakdown of actual and forecast costs<br>Supporting information, legal fees, consultant fees, costs awards, etc. | Yes | Exhibit F, Tab 9, Schedule 1<br>Exhibit C, Tab 2, Schedule 4<br>Exhibit F, Tab 4, Schedule 1 |
| *Charitable and Political Donations* | *Not applicable* | | |
| 29 | File the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s). | N/A | Exhibit F, Tab 10, Schedule 1 |
| 29 | Detailed information for all contributions that are claimed for recovery | N/A | |
| 29 | Charitable Donations - confirmation that political contributions not included | N/A | |
| *Depreciation, Amortization and Depletion* | | | |
| 29 | Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years.<br>Asset amount and rate of depreciation/amortization must tie back to the accumulated depreciation balances in the continuity schedule under rate base. *(not applicable historical and bridge years)* | Yes | Exhibit F, Tab 11, Schedule 1 |
| 29 | Identification of any Asset Retirement Obligations and associated depreciation, accretion expense | N/A | |
| 29 | Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided | N/A | |
| 29 | Depreciation/amortization policy<br>Summary of changes to depreciation/amortization policy since last CoS | N/A | |
| 29 | Explanation of any deviations from depreciating components of PP&E separately | N/A | |
| *Taxes or PILs and Property Taxes* | | | |
| 30 | Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years. *(not applicable historical and bridge years)* | Yes | Exhibit F, Tab 12, Schedule 1 |
| 30 | Supporting schedules and calculations identifying reconciling items | Yes | Exhibit F, Tab 12, Schedule 1 Attachments 1 |
| 30 | Most recent federal and provincial tax returns | Yes | Exhibit F, Tab 12, Schedule 1 Attachments 2 |
| 30 | Financial Statements included with tax returns if different from those filed with application | N/A | |
| 30 | Calculation of Tax Credits; redact where required (filing of unredacted versions is not required) | N/A | |
| 30 | Supporting schedules, calculations and explanations for other additions and deductions | Yes | Exhibit F, Tab 12, Schedule 1 Attachments 1 |
| *Non-recoverable and Disallowed Expenses* | *Not applicable* | | Exhibit F, Tab 14, Schedule 1 |
| 30 | Exclude from regulatory tax calculation any non-recoverable or disallowed expenses | N/A | |

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| *Integrity Checks* | | | |
| 31 | Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application | Yes | Exhibit F, Tab 12, Schedule 1 |
| 31 | The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years. *(not applicable historical and bridge years)* | Yes | Exhibit F, Tab 12, Schedule 1 |
| 31 | Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st | N/A | |
| 31 | The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed. *(not applicable historical and bridge years)* | N/A | |
| 31 | Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application *No carry forward from previous returns* | N/A | |
| 31 | CCA is maximized even if there are tax loss carry-forwards | Yes | Exhibit F, Tab 12, Schedule 1 |
| 31 | A statement is included in the application as to when the losses, if any, will be fully utilized | Yes | Exhibit F, Tab 12, Schedule 1 |
| 31 | Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation | N/A | |
| 31 | The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding. | Yes | Exhibit F, Tab 12, Schedule 1 |
| *Z-Factor Claims* | *Not applicable* | | |
| **31** | Evidence that z-factor costs incurred meet eligibility criteria, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement | N/A | Exhibit F, Tab 16, Schedule 1 |
| **EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE** | | | |
| *Capital Structure* | | | |
| 33 | OEB's cost of capital parameters used | Yes | Exhibit G, Tab 2, Schedule 1 |
| 33 | Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years | Yes | Exhibit G, Tab 1, Schedule 1 |
| 33 | Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules | Yes | Exhibit G, Tab 2, Schedule 2 - 4 |
| 33 | Explanation for any changes in capital structure | N/A | |
| *Cost of Capital (Return on Equity and Cost of Debt)* | | | |
| 34 | Calculation of cost for each capital component | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Profit or loss on redemption of debt | N/A | |
| 34 | Copies of promissory notes or other debt arrangements with affiliates | N/A | |
| 34 | Explanation of debt rate for each existing debt instrument | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Forecast of new debt in bridge and test year - details including estimate of rate | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions | N/A | |
| *Not-for-Profit Corporations* | | | |
| 34 | Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves | N/A | |
| **EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS** | | | |
| **34** | List of all outstanding DVA and sub-accounts; provide description of DVAs | Yes | Exhibit H, Tab 1, Schedule 1 |
| **34** | Completed DVA continuity schedule for period following last disposition to present - live Excel format | N/A | |
| **34** | Confirm use of interest rates established by the OEB by month or by quarter for each year | Yes | Exhibit H, Tab 1, Schedule 1 |
| **35** | Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS | N/A | |
| **35** | A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule | N/A | |
| **35** | Statement as to any new accounts, and justification. | Yes | Exhibit H, Tab 1, Schedule 1 |
| **35** | Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents | N/A | |
| *Disposition of Deferral and Variance Accounts* | | | |
| 36 | Identify accounts for which disposition is sought | N/A | |
| 36 | Identify accounts for which disposition is not sought and the reasons | N/A | |
| 36 | Propose the method to be used for recovery or refund of balances that are proposed for disposition | N/A | |
| 36 | Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements | N/A | |
| 36 | Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account | N/A | |
| 36 | Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference | N/A | |
| 36 | Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period | N/A | |

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| **EXHIBIT 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants** | | | |
| | | | |
| 36 | Identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection | Yes | Exhibit I, Tab 1, Schedule 1 |
| 36 | Steps taken to functionalize the assets in the functional categories | Yes | Exhibit I, Tab 1, Schedule 1 |
| 36 | Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets | Yes | Exhibit I, Tab 1, Schedule 1 |
| 36 | Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools | Yes | Exhibit I, Tab 1, Schedule 1 |
| **EXHIBIT 10 - Rate Design for Uniform Transmission Rates** | | | |
| *Bill Impact Information* | | | |
| 37 | Provide bill impact of the application including the dollar and percentage impact on the average customer's total bill and the percentage impact on transmission rates | Yes | Exhibit J, Tab 1, Schedule 1 |
| 37 | Bill impacts for typical customers and consumption levels. | Yes | Exhibit J, Tab 1, Schedule 1 |
| *Setting the Uniform Transmission Rates* | *Not applicable* | | Exhibit J, Tab 2, Schedule 1 |
| 37 | Overview of how the UTR are established in Ontario and how these rates are determined | N/A | |
| 37 | The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool | N/A | |
| 37 | Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates | N/A | |
| 37 | A table explaining and documenting the determination of the UTR including:<br>- previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool;<br>- OEB file number of each decision approving each revenue requirement and charge determinant;<br>- proposed revenue requirements and charge determinants as proposed in the application;<br>- the calculation of the UTR for each pool;<br>- the transmission revenue allocator for each of the Ontario transmitters in the pool;<br>- an explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates | N/A | |

# Distribution System Plan Checklist (as applied to the TSP)

**NextBridge Infrastructre**

| Filing Requirement Page # Reference | | | November 2020 |
|---|---|---|---|
| | | Yes/No/N/A | Evidence Reference, Notes |
| **DISTRIBUTION SYSTEM PLAN REQUIREMENTS** | | | |
| **Ch 5 p7-8** | Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table | **Yes** | |
| **Ch 5 p8-9** | (Ch. 5.2.1) Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | **Yes** | Exhibit B - Transmission System Plan |
| **Ch 5 p9-10** | (Ch. 5.2.2) Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- IESO letter in relation to REG investments (Ch 5 p10) and Dx response letter | **Yes** | Exhibit B, Tab 1, Schedule 5 |
| **Ch 5 p10-12** | (Ch. 5.2.3) Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | **Yes** | Exhibit D, Tab 1, Schedule 1 |
| **Ch5 p13** | (Ch. 5.3.1.a) Asset Management Process Overview - description of AM objectives/corporate goals and how objectives for prioritizing investments are ranked | **Yes** | Exhibit B, Tab 1, Schedule 4 |
| **Ch5 p13** | (Ch. 5.3.1.b) Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | **Yes** | Exhibit B, Tab 1, Schedule 4 |
| **Ch 5 p14** | (Ch. 5.3.2) Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | **Yes** | Exhibit B, Tab 1, Schedule 4 |
| **Ch 5 p14-15** | (Ch. 5.3.3) Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | **Yes** | Exhibit B, Tab 1, Schedule 4 |
| **Ch 5 p17-18** | (Ch. 5.4.1) Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments | **Yes** | Exhibit B, Tab 1, Schedule 6 |
| **Ch 5 p19-20** | (Ch. 5.4.2) Capital Expenditure Summary is to provide a snapshot of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or trigger) driver of the investment. | **Yes** | Exhibit B, Tab 1, Schedule 6 |
| **Ch 5 p20** | (Ch. 5.4.3) Justifying capital expenditures - Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures. | **Yes** | Exhibit B, Tab 1, Schedule 6 |
| **Ch 5 p20-21** | (Ch. 5.4.3.1) Capital Expenditure Summary by Investment Category - The OEB's assessment of DSPs includes the costs of material projects/programs included in the DSP, as well as how the overall DSP budget is allocated to each of the<br>four investment categories. | **Yes** | Exhibit B, Tab 1, Schedule 6 |
| **Ch5 p21-28** | (Ch. 5.4.3.2) Material Investments - For each project that meets materiality threshold set in Ch 2 p10<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | **Yes** | Exhibit B, Tab 1, Schedule 6 |

# EXECUTIVE SUMMARY

1. This Exhibit describes the scope and key aspects of NextBridge's Application for the approximately 450 kilometers ("**km**") of 230 kilovolt ("**kV**") double circuit transmission line that runs from the Lakehead transformer station ("**TS**") to the Wawa TS, the East-West Tie line and its proposed approach to set transmission rates for the incentive rate period of April 1, 2022 to December 31, 2031 ("**IR Term**"). It also provides an overview of NextBridge's proposed business plan, Operations, Maintenance, and Administration ("**OM&A**") approach and the basis of and justification for requested variance accounts. To the extent not already set forth above, this Exhibit also provides the Administration information requested under Section 2.3.4 of the Chapter 2 Filing Requirements.

## Scope of the Application

2. In this Application, NextBridge requests the OEB approval for:

- Transmission rates for the IR Term set by a custom incentive rate formula;
  - A revenue requirement determined by using a cost of service, forward looking test year;
  - Based off the test year, establish a proposed RCI for revenue requirements starting on April 1, 2022 and ending on December 31, 2031;
- Inclusion in the 2022 UTR for the Network pool
- Accounting orders establishing the following:
  - Taxes or Payments in Lieu of Taxes Variance Account;
  - Revenue Differential Variance Account;
  - Construction Cost Variance Account; and
  - Debt Rate Variance Account.

3. A number of internal and external challenges will have to be managed over the IR Term. They include:

- Rising income tax expense as NextBridge's capital cost allowance ("**CCA**") declines;
- Managing NextBridge's Right-of-Way ("**ROW**") vegetation maintenance program, taking into consideration the six-year vegetation cycle and an expected increase in forestry expenses during certain test years with greater work volumes;
- Potential maintenance and labour cost increases;
- Bird nest removal and bird excrement-associated damages;
- Localized extreme weather event(s) (*e.g.*, icing, lightning and fire related damage) and associated remediation;
- Fixed Consumer Price Index ("**CPI**") for First Nations reserve crossing permits may not align with inflation;
- New First Nations Reserve Land that could be added to the land base of the project requiring new Federal agreements and payments;
- Unexpected damage from ROW users or wildlife (*e.g.,* vandalism, bears eating plastic guy-wire markers or snowmobilers accidentally damaging a tower or guy-wire); and
- Potential compliance changes through the North American Electric Reliability Corporation ("**NERC**") which will flow through the Northeast Power Coordinating Council ("**NPCC**") and IESO.

4. NextBridge's incentive rate Application, as proposed, will mitigate these challenges, maintain financial performance and ensure that NextBridge's assets are managed efficiently and effectively to foster minimal bill impacts.

5. This Application will result in a base revenue requirement of $55.7 million, which will be prorated in 2022 to $41.8 million. Since this is the first year of operation for NextBridge, there is no prior year performance comparison.

6. The implementation of a new transmission project that was not previously included in transmission rates results in an increase to the average transmission rates in Ontario. The revenue requirement will result in a total bill impact of less than 0.32% for a typical residential customer consuming 750 kW per month. Further details may be found in Exhibit J, Tab 1, Schedule 1.

**Projected In-service Date**

7. The emergence of health threats associated with Novel Coronavirus 2019 ("**COVID-19**"), caused unforeseeable delays in current construction activities. As a result of these unavoidable delays, at NextBridge's request the IESO confirmed that there is no unacceptable risk to reliability created if the projected in-service date for the East-West Tie line was shifted to on or before March 31, 2022. Further information can be found in the transmission system plan ("**TSP**") in Exhibit B, Tab 1.

**Overview of the Utility and Description of Partnership**

8. The Applicant, UCT operating as NextBridge, is a New Brunswick corporation established for the purpose of developing, owning, and operating transmission facilities in Ontario known as the East-West Tie line in its capacity as the general partner, acting for and on behalf of the limited partnership, NextBridge Infrastructure LP. The limited partners are: (A) NextEra Energy NextBridge Holding, ULC ("**NextEra**"), a British Columbia unlimited liability company; (B) Enbridge Inc. ("**Enbridge**"), a Canadian corporation, and (C) Borealis NB Holdings, Inc. ("**OMERS**"), an Ontario corporation. At the time of commercial operations, NextBridge will be owned 40% by NextEra, 20% by Enbridge, 20% by OMERS, and 20% by Bamkushwada, LP (**"BLP"**) a corporation made up of six First

Nations. Further information can be found in the Administration section in Exhibit A, Tab 6.

**NextBridge's Strategic Objectives**

9. NextBridge's strategic objectives consist of the following:

- Foster positive and constructive relationships with Indigenous and non-Indigenous communities;
- Maintain a reliable, cost-effective transmission system;
- Protect and sustain the environment for future generations; and,
- Maintain a commercial culture that increases value for its owners.

In the implementation of these strategic objectives, during both the construction and operations periods, NextBridge works directly with its stakeholders and contractors, to review the above objectives incorporating maintenance programs and work plans for efficiency, reliability, and safety. Further information can be found in the TSP in Exhibit B, Tab 1, Schedule 3.

## A. Revenue Requirement

10. This Application requests approval of a revenue requirement and the establishment of an RCI for the period starting on, April 1, 2022 through December 31, 2031 determined by using a forward test-year approach and an annual revenue adjustment based on the Board's incentive regulation approach. NextBridge has proposed this RCI period instead of the minimum 5-year term because the East-West Tie line is a single asset and its rates will not be changing significantly during this term. Implementing a longer IR term will result in fewer proceedings before the Board and in turn greater savings to ratepayers.

11. The revenue requirement shown below is for a full year's cost of service based on a Test Year of April 1, 2022 – March 31, 2023 ("**Test Year**"). NextBridge proposes the amount

requested in the 2022 UTR be prorated to accommodate for the project being in service for only nine months of 2022 as reflected in Tables 1 and 2 below.

**Table 1. Summary of Revenue Requirement for Test Year ($ Millions)**

| Component | Test Year | Reference |
|---|---|---|
| OM&A | 4.9 | Exhibit F, Tab 1, Schedule 1 |
| Depreciation | 9.3 | Exhibit F, Tab 11, Schedule 1 |
| Income Taxes | 0.6 | Exhibit F, Tab 13, Schedule 1 |
| Return on Capital | 41.0 | Exhibit G |
| **Base Revenue Requirement** | **55.7** | |

**Table 2. 2022 Revenue Requirement Converted to UTR Amount ($ Millions)**

| 2022 Revenue Requirement converted to UTR Amount ($ Millions) | | |
|---|---|---|
| 2022 | A = Cost of Service for 12 months | 55.7 |
| 2022 | B = Monthly Cost of Service or A/12 | 4.6 |
| 2022 | C = 2022 UTR Amount or B * 9 | 41.8 |

12. To establish the annual revenue requirements for 2023 to 2031, an RCI is proposed in which the revenue requirement for 2023 is equal to the revenue requirement in the Test Year, inflated by the RCI.

The RCI is expressed as:

$$\mathrm{RCI} = \mathrm{I} - \mathrm{X}$$

Where:

- "I" is the Inflation Factor, based on the OEB's inflation factor for incentive rate setting
- "X" is the Productivity Factor, which includes a Stretch Factor.

13. NextBridge proposes to adopt the OEB's calculation of the RCI Inflation Factor ("**I**") parameter, which effective for 2020 is 2%. The proposed Inflation Factor is an external measurement of industry labour/non-labour weights with a weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI
- 30% weight of the annual percentage change in the Average Weekly Earnings for workers in Ontario

14. NextBridge proposes a 0% Productivity Factor ("**X**") to be applied annually over the 2023 to 2031 period. NextBridge is a new entrant and has a structure unlike other transmission and distribution companies in Ontario. NextBridge's proposal reflects these circumstances and is appropriate for the following reasons:

- NextBridge's assets are new, and, therefore, minimal OM&A was included in the Test Year revenue requirement. Changes in OM&A have to be absorbed within the RCI construct.
- NextBridge's only controllable costs are OM&A where productivity is normally realized. Because of the small amount of OM&A and also in comparison to the non-controllable costs (*e.g*. cost of capital, depreciation, income tax), productivity is nearly impossible to realize.

- NextBridge has proposed capital expenditures to improve the operation and maintenance of the line, but has not included the capital increases in rate base during the IR Term. The Inflation Factor will help offset the financial impact of these capital expenditures.
- NextBridge will have no employees, while maintaining access to highly qualified resources through the service agreements with NEET, and HONI and Supercom Industries Ltd. ("**Supercom**") that are available as needed, allowing NextBridge to remain cost efficient. Supercom is a partnership of the six BLP First Nations tasked with the goal of maximizing First Nations and Métis participation in the East-West Tie project.
- A service agreement on maintenance operations will be awarded to a partnership between HONI and Supercom ("**HONI SLA**") allowing efficiencies to these companies by allowing utilization of resources already available in the region. Given the proximity of the East-West Tie line to the Hydro One's existing East-West transmission and station assets, maintenance can be optimized when work can be performed in the same area of both lines simultaneously (*i.e.,* vegetation maintenance). The gained efficiencies are passed through to ratepayers as an avoided cost to NextBridge deploying separate crews in the same area.
- The NextBridge partnership has tax efficient partners and the savings of lower income tax costs have been incorporated in the revenue requirement.

## B. Budgeting Assumptions

15. NextBridge has identified capital projects in accordance with its 10-year capital plan in its TSP following the March 31, 2022 in-service date but is not requesting these capital expenditures be included in a deferral account or added to the revenue requirement during the currently requested IR Term. Therefore, economic assumptions concerning inflation and exchange rates that could affect the cost of the capital expenditures are not included in this Application.

## C. Load Forecast Summary

16. Given the East-West Tie line is a transmission line only, NextBridge has no delivery points or metering points (*i.e.*, no load customers), and, therefore, it has not included a load forecast. All power transported using the East-West Tie line is delivered to the final customer by another transmitter, and, thus, is included in another transmitter's load forecast. The revenue requirement is allocated to the provincial Network rate pool, as all assets serve the Network with no transformation or individual customer services. Once the revenue requirement by rate pool has been established, rates are determined by applying the provincial charge determinants for each pool to the total revenue for each pool.

17. In addition to the August 28, 2020 letter from the IESO confirming that an in-service date of March 31, 2022 does not present an unacceptable risk to reliability, a detailed economic overview and consideration of capacity needs associated with the East-West Tie line were studied and provided by the IESO. Those IESO's assessments dated December 15, 2015, June 29, 2018 and December 1, 2017 are attached as Exhibit B, Tab 1, Schedule 5, Attachments 1-3.

## D. Transmission System Plan

*Transmission plan*

18. NextBridge's TSP is included in Exhibit B. The TSP is consistent with Chapter 2 of the *Transmission Filing Requirements*, as well as the guidance in Chapters 3 and 5 of the *Distribution Filing Requirements*.

19. The planning tools, processes, and investments outlined in greater detail in the TSP represent the current state of the assets being constructed by NextBridge. The TSP is intended to provide informational support to the ratepayers and stakeholders of Ontario. The TSP is distinct from most transmission and distribution system plans submitted to the

OEB. As a single asset and newly constructed line, it is expected that the capital expenditures and increases in OM&A will be managed over the IR Term. The information included in the TSP is current as of the filing of this Application.

20. NextBridge's operational needs have been assessed and assumptions are included in the OM&A budget and will be assessed going forward on an annual basis. This is then incorporated into its investment planning process to establish a plan that addresses those operational needs while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets.

*Asset utilization and optimization*

21. NextBridge will adhere to applicable national and international standards such as the Canadian Standards Association, the Institute of Electrical and Electronic Engineers, the International Electrotechnical Commission, and NERC Standard FAC-003-04, ("**Transmission Vegetation Management**"). Affiliates of NEET presently develop and operate transmission assets across North America, and are required to comply with NERC Reliability Standards. Collectively, affiliates of NEET own more than 14,000 km of transmission lines and nearly 830 substations in North America as of December 31, 2019 which are delivering reliable electric service throughout North America.

22. Additionally, NextBridge will optimize asset management throughout the East-West Tie line's life cycle. To achieve this goal, NextBridge will work closely with NEET, utilizing NEET's extensive expertise and experience, to monitor its transmission system assets, identify and define needs, and determine the optimal timing for maintenance activities and opportunities to invest that maintain high reliability and reduce maintenance expenses over the long term. In working with NEET and its affiliated companies, NextBridge will deliver a high level of transmission service that is responsive to operational needs, while

also minimizing rate impacts and risks in support of the company's strategic objectives. Additional details are available in Exhibit 2 of this Application.

23. The majority of NextBridge's maintenance services were competitively bid and will be awarded to a partnership between HONI and Supercom, which will result in a service level agreement to plan and organize the operation and maintenance of the assets. Given the proximity of the East-West Tie line to HONI's existing East-West transmission and station assets, maintenance can be optimized when work can be performed on both lines simultaneously (*i.e.*, vegetation maintenance). These gained efficiencies are passed through to ratepayers as a reduced maintenance expense. As of the date of this application, the service level agreement with HONI and their partner, Supercom Industries ("**HONI SLA**") is being finalized and will be filed as an update to the Application when available. An overview of the HONI SLA are described in Exhibit B, Tab 1, Schedule 4.

*Asset condition assessment*

24. The asset profile utilized by NextBridge tracks the average age of the components and the expected service life ("**ESL**"). The ESL is defined as the average duration in years that an asset can be expected to operate under normal system conditions and is determined by similar useful life data presented in HONI's rate case (EB-2019-0178 and EB-2018-0275). Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition. The depreciation of the East-West Tie line is aligned with the overall expected life of the assets that comprise the project.

25. Asset condition assessments are conducted for each asset as they reach an individual age threshold, which varies depending on asset type. They are categorized as low, fair, and high risk assets relative to their likelihood of near-term failure. Low risk assets are "like new" or have not yet reached an age where condition assessment is required. Since the East-West Tie line is new, all assets fall in the "like new" category. Fair risk assets have condition test results that indicate minor deterioration but have not yet reached end

have condition test results that indicate minor deterioration but have not yet reached end of life ("**EOL**"). These assets will be scheduled for reassessment at a later date, depending on the level of deterioration indicated by the test results.

26. EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL, they may not be at EOL. At the same time, as the primary driver of replacement decisions, asset condition will be verified prior to work being undertaken. Additional details can be found in in Exhibit B.

*Capital Expenditure Summary*

27. This section provides the details of the overall capital expenditure plan that NextBridge will undertake over the 2022 to 2031 IR Term and other pertinent information regarding the elements of the planning process. Table 3 provides a summary of NextBridge's overall capital plan. NextBridge will manage planned capital spending over the ten-year horizon to ensure expenditures are made to improve reliability and reduce long term maintenance costs for the life of the project.

**Table 3. Overall Capital Plan ($ Millions)**

| Capital Plan ($ Millions) | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| General Plant - Office & Vehicles | - | 0.16 | 0.11 | 0.01 | 0.15 | - | - | 0.20 | - | - |
| Storage Yard | - | - | - | 0.30 | - | - | - | - | - | - |
| Reliability - Bird Deterrents, ROW Cameras | 0.23 | 0.43 | 0.63 | 0.33 | 0.13 | 0.20 | 0.40 | 0.60 | 0.30 | 0.10 |
| **Total** | **0.23** | **0.59** | **0.74** | **0.64** | **0.28** | **0.20** | **0.40** | **0.80** | **0.30** | **0.10** |

28. This plan provides for increased reliability by taking advantage of new technology and equipment to reduce potential outages and gain additional situational awareness of real-time conditions at various critical crossings in the line. The capital expenditures for the project to be spent over the IR Term can be divided into three areas: general plant; storage yard; and reliability. This is further explained in Exhibit B.

## E. Rate Base

29. The requested rate base for the Test Year (April 1, 2022 to March 31, 2023) is presented in Table 4 below, and further details on the rate base are presented in Exhibit C, Tab 1, Schedule 1.

**Table 4. Transmission Rate Base ($ Millions)**

| Transmission Rate Base ($ Millions) | Test Year[1] |
|---|---|
| Average Gross Plant | 775.1 |
| Average Accumulated Depreciation | 4.6 |
| **Average Net Plant** | **770.4** |
| Cash Working Capital | N/A |
| Materials and Supply Inventory | N/A |
| **Transmission Rate Base** | **770.4** |

30. As a new entrant, NextBridge has no prior rate base, and, therefore, no change in rate base is included from any prior OEB approval.

## F. Performance and Reporting

31. NextBridge is proposing to utilize a set of measures that best demonstrate its performance and address the performance standards for transmitters as set out in Chapter 4 of the *Transmission System Code*. The proposed performance measures and their associated RRFE performance outcomes are shown in Table 5 below.

**Table 5. Performance Measures**

| RRFE Outcomes | Performance Measure |
|---|---|
| Safety | 0.00 OHSA[2] Recordable Injuries Per Year |
| Financial Performance | Return on Equity |
| Public Policy Responsiveness | Applicable NERC Reliability Standards, such as FAC-003-4, Vegetation Compliance for NextBridge owned assets |

[1] Totals may not foot due to rounding
[2] Occupational Health and Safety Act, R.S.O. 1990, c.1 ("OHSA").

| RRFE Outcomes | Performance Measure |
|---|---|
| Operational Excellence | OM&A Cost ($K) per circuit km |
| Operational Excellence | Average System Availability (%) |

32. Given the nature of NextBridge's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. NextBridge's assets consist solely of a 230 kV double circuit transmission line and do not include any terminal breakers or other operable assets, as the demarcation point of each of the circuits is a tower outside of the transformer stations as noted in Exhibit B. NextBridge does not have any customer delivery points (or meter assets), which are the basis of common reliability performance measures such as System Average Interruption Duration Index ("**SAIDI**") and System Average Interruption Frequency Index ("**SAIFI**"). In addition to these operating characteristics, the life-cycle of NextBridge's assets detracts from meaningful comparisons. Therefore, NextBridge's performance measures do not readily provide meaningful comparisons to other transmitters. On this basis, NextBridge proposes to measure system availability to demonstrate the reliability performance of the assets. Notwithstanding, and although NextBridge has no customers, it is proposing a safety metric with a performance measure of zero recordable injuries per year.

33. NextBridge has no areas of non-compliance, and, therefore, there is no discussion of non-compliance in the Application.

## G. Operations, Maintenance, and Administration (OM&A) Expense

34. OM&A expenses relate to certain services NextBridge will undertake to ensure ongoing reliability of the line post-construction starting after the in-service date.

35. Field based maintenance services will be provided under the HONI SLA to perform maintenance of the assets. The roles of the NextBridge's two dedicated field personnel

compared to the activities performed by HONI and their partner Supercom Industries under the terms of the HONI SLA are explained at Table 2 in Exhibit B, Tab 1, Schedule 4. A portion of operations and maintenance costs will also be administered under an affiliate agreement between the NextBridge partners described in Exhibit F. Examples of these services are:

*Operating services (provided by NextBridge and/or its partners)*

- Monitoring/control of the transmission system, including alarm monitoring, asset monitoring, and minor control
- Asset operation within HONI-prescribed limits including the Application of HONI equipment directives and switching on HONI's transmission system to regulate NextBridge's East-West Tie line
- Emergency response notifications for transmission system events, including response to IESO-directed emergency actions, and implementation of load shedding
- Outage processing including scheduling, planning, and submitting to IESO
- Crew dispatching, including 24/7 assessment, contacting, and dispatching, and coordination with HONI
- Record maintenance including retention of logged items

*Maintenance services (majority provided by HONI/Supercom)*

- Overhead transmission lines maintenance including thermovision, helicopter, and ground patrols
- Transmission ROW maintenance, including mandatory annual NERC vegetation patrols, line clearing, brush control, condition patrol, and property owner notifications

36. Further details on the maintenance services are presented in Exhibit B.

37. The total OM&A expense is $4.94 million in the Test Year (April 1, 2022 to March 31, 2023). There is no information comparing the OM&A to a change from the last approved OM&A, given this is NextBridge's first request for revenue requirements. Further details on the OM&A costs are provided in the following Table 6:

**Table 6. NextBridge OM&A Expense ($ Millions)**

| OM&A Expense ($ Millions) | Test Year |
|---|---|
| Operations & Maintenance | 1.27 |
| Regulatory | 0.07 |
| Compliance & Administration | 1.67 |
| Indigenous Participation | 0.89 |
| Indigenous Compliance | 0.44 |
| Property Taxes & Rights Payments | 0.60 |
| **Total OM&A** | **4.94** |

## H. Cost of Capital

38. NextBridge's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base, where the 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt. This structure is consistent with the OEB's report on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084), and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016. The table below outlines NextBridge's cost of capital.

| | % | % |
|---|---|---|
| Long-term debt | 56% | 3.21% |
| Short-term debt | 4% | 2.75% |
| Common equity | 40% | 8.52% |
| **Total** | **100%** | **5.32%** |

39. NextBridge anticipates that the initial financing of the East-West Tie line will occur after the OEB issues its decision and order in this proceeding, since the initial financing will occur in close proximity to the in-service date and NextBridge is requesting either interim or final rates prior to the in-service date. Therefore, NextBridge proposes to use a DRVA to track and conduct a one-time update to the revenue requirements at the first annual update for rates in 2023 to reflect NextBridge's actual long-term cost of debt.

## I. Cost Allocation and Rate Design

40. All assets associated with NextBridge's East-West Tie line are classified as Network assets. Accordingly, all of the rates revenue requirements associated with NextBridge's transmission assets will be allocated to the Network pool. Further details regarding the cost allocation and rate design can be found in Exhibits I and J.

## J. Deferral and Variance Accounts

41. In this proceeding, NextBridge is requesting the establishment of the following new accounts with an effective date of April 1, 2022: (A) debt rate variance account; (B) taxes or payments in lieu of taxes variance account; and (C) revenue differential variance account. NextBridge is also requesting the establishment of a construction cost variance account with an effective date of the filing of this Application. Each of these accounts are presented in further detail in Exhibit H, Tab 1, Schedule 1.

42. The establishment and approval of the accounting orders for a PILsVA effective April 1, 2022, as described in Exhibit H, Tab 1, Schedule 1;

43. The establishment and approval of the accounting orders for a RDVA effective April 1, 2022, as described in Exhibit H, Tab 1, Schedule 1;

44. The establishment and approval of the accounting orders for a CCVA to be made effective the same date of the filing of this Application, as described in Exhibit H, Tab 1, Schedule 1;

45. The establishment and approval of the accounting orders for a DRVA to track and effectuate the one-time update to the cost of long-term debt to reflect the actual cost of long-term debt associated with the financing of East-West Tie line, as described in Exhibit H, Tab 1, Schedule 1;

**K. Bill Impacts**

46. The bill impacts that result from the approval of this Application, along with illustrative bill impacts for the IR Term, can be found in Exhibit J, Tab 1, Schedule 1. Tables 7 to 9 below show the average 2022 bill impacts of the proposed changes in transmission rates. The addition of the East-West Tie line in transmission rates results in an increase of 3.31% in transmission costs since it is a new project that was not previously included in the UTR.

**Table 7. Estimated Transmission Cost as a Percentage of Total Electricity Market**

| Bill Component | ¢/kWh | Source |
|---|---|---|
| Commodity | 12.58 | IESO Monthly Market Report December 2019 |
| Wholesale Market Service Charges | 0.39 | IESO Monthly Market Report December 2019 |
| Wholesale Transmission Charges | 1.06 | IESO Monthly Market Report December 2019 |
| Distribution Service Charges | 3.02 | 2019 Yearbook of Electricity Distributors |
| **Total Cost** | **17.05** | |
| *Transmission as % of Total Cost for Dx-connected customers* | *6.2%* | |
| *Transmission as % of Total Cost for Tx-connected customers* | *7.6%* | |

**Table 8. Average Bill Impacts on Transmission and Distribution-Connected Customers (Test Year)**

| Category | 2022 |
|---|---|
| Rates Revenue Requirement ($ Millions) | $55.7 |
| % Increase in Rates Revenue Requirement over prior year | N/A |
| % Impact of load forecast change | N/A |
| NB Rates Revenue Requirement as a % of all transmitters | 3.31% |
| **Net Impact on Average Transmission Rates** | **3.31%** |
| Transmission as a % of Tx-connected customer's Total Bill | 7.6% |
| **Estimated Average Bill impact** | **0.25%** |
| Transmission as a % of Dx-connected customer's Total Bill | 6.2% |

**Table 9. Average Bill Impacts on Transmission and Distribution-Connected Customers (IR Term)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| Rates Revenue Requirement ($M) | 55.7 | 56.8 | 58.0 | 59.1 | 60.3 | 61.5 | 62.8 | 64.0 | 65.3 | 66.6 |
| % Increase in Rates Revenue Requirement over prior year | N/A | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |
| % Impact of load forecast change | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **Net Impact on Transmission Revenue Requirement** | 3.31% | 0.07% | 0.07% | 0.07% | 0.07% | 0.07% | 0.07% | 0.07% | 0.08% | 0.08% |
| Transmission as a % of Tx-connected customer's Total Bill | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% | 7.56% |
| **Estimated Bill impact TX Connected customers** | 0.25% | 0.00% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% |
| Transmission as a % of Dx-connected customer's Total Bill | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% | 6.22% |
| **Estimated Bill impact DX connected customers** | 0.21% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

47. The total bill impact for a typical HONI medium density residential customer consuming 750 kWh, and for a typical HONI General Service customer consuming 2,000 kWh/month is determined based on the forecast increase in the customer's Retail Transmission Service Rates as detailed below in Table 10. The inclusion of the East-West Tie line in transmission rates results in an increase in a typical residential customer of 0.32% and an amount, that rounds to zero, in a typical general services energy customer.

**Table 10. Typical Customer Monthly Bill Impacts**

| Typical Medium Density (R1) Residential Customer Bill Impacts | Typical Medium Density (HONI R1) Residential Customer 750 kWh | Typical General Service Energy less than 50 kW (HONI GSe < 50kW) Customer 2,000 kWh |
|---|---|---|
| Total Bill as of May 13, 2020 | $108.85 | $338.82 |
| RTSR included in R1 Customer's Bill (based on 2019 Interim UTR) | $12.27 | $25.87 |
| *Estimated 2022 Monthly RTSR* | $12.62 | $26.61 |
| **2022 increase in Monthly Bill** | **$0.35** | **$0.75** |
| *2022 increase as a % of total bill* | *0.32%* | $0.00 |

48. Consistent with the Filing Requirements for Electricity Transmission Applications, Section 2.1.1, the materiality threshold for NextBridge is calculated to be $278,500, based on Revenue Requirement of $55,700,000 x 0.5%.

**Conclusion**

49. NextBridge's Application balances the needs of its system and assets and allows it to operate and maintain these assets in accordance with applicable reliability standards and to satisfy regulatory, environmental, and legal requirements.

50. NextBridge operates under unique circumstances, unlike those of most other transmission companies in Ontario, when considering its corporate structure, asset holdings, and operating and management arrangements. In consideration of these unique circumstances, NextBridge has made every effort to align its Application with the OEB's expectations under the RRFE.

51. Over the ten-year term, this Application, as proposed, will mitigate the company's challenges, maintain the Partnership's financial performance and ensure that NextBridge's assets are managed effectively to benefit electricity customers across Ontario.

# CUSTOMER ENGAGEMENT

1. While NextBridge does not have any direct customers and, therefore, has not conducted formal customer engagement activities and analysis, NextBridge has conducted customer outreach and discussions with HONI and the Indigenous and non-Indigenous communities located in the East-West Tie line's affected area in Northwestern Ontario. NextBridge has met with HONI on a number of occasions to coordinate work on the technical processes and details associated with East-West Tie line dead-end structures to be located outside of the Lakehead TS, Marathon TS, and Wawa TS, as well as the crossing of existing transmission lines. As the East-West Tie line is designed to address reliability of electricity service in Northwestern Ontario, NextBridge has conducted a number of open houses and discussion with the Indigenous and non-Indigenous communities, as well as other stakeholders, that will benefit from the reliability associated with the East-West Tine line.

2. In attendance at these open houses were members of the Ontario Power Authority, now the IESO and hereinafter referred to as the IESO, who presented materials on the potential for demand ROW in the Northwest and the associated need for electricity supply. Open house presentation materials can be found at Exhibit A, Tab 4, Schedule 1, Attachment 1. Additionally, as part of the environmental assessment ("**EA**") process, NextBridge has had numerous engagements with Indigenous and non-Indigenous communities. A full record of these engagements can be found online at http://www.nextbridge.ca/regulatory-approvals. Letters of support from local communities can be found in NextBridge's LTC proceeding in Staff Interrogatory #53 included here as Exhibit A, Tab 4, Schedule 1, Attachment 2.

# OPEN HOUSE PRESENTATION MATERIALS

NEXTBRIDGE INFRASTRUCTURE

# EAST-WEST TIE TRANSMISSION PROJECT

## *Connecting Ontario's Northwest*

**THANK YOU**

for attending this Open House

*We want to hear from you*

www.nextbridge.ca

# Purpose of the Open House

**We are here to provide you with information about the following:**

- Overview of the proposed project;
- Terms of Reference for the Environmental Assessment process; and
- NextBridge's commitment to engagement and consultation.

**<u>We are here to listen</u> to your comments and questions about:**

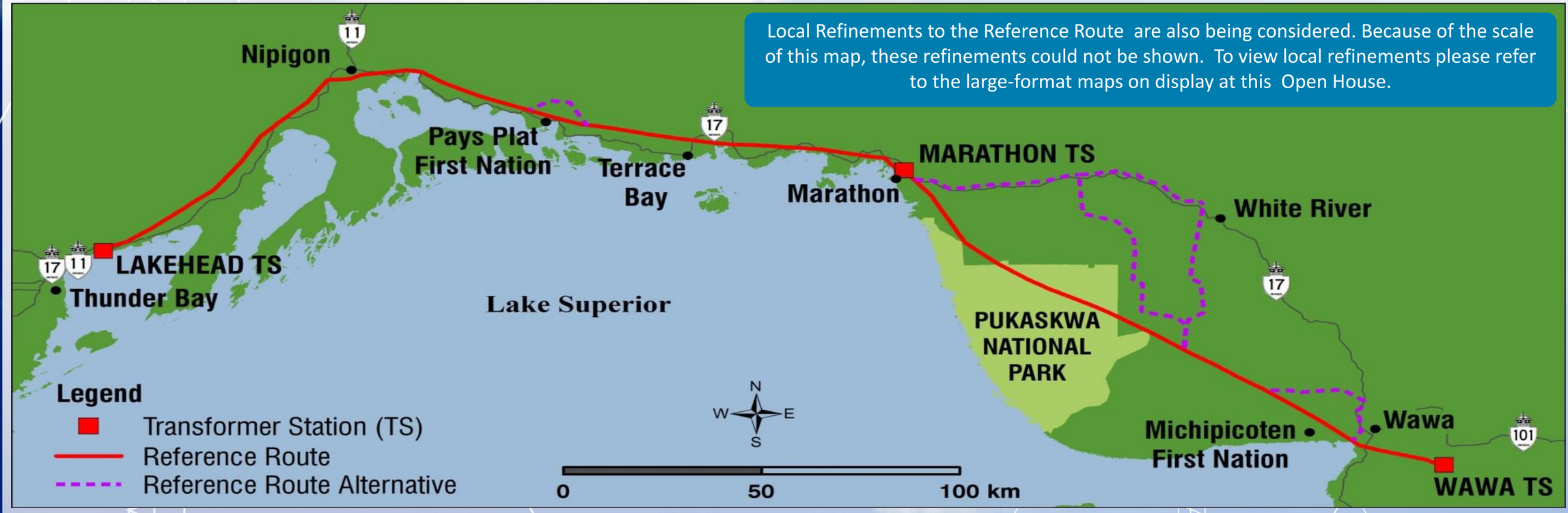
- The project, including the proposed reference route and routing alternatives;
- Studies and engagement activities proposed;
- What is important to you and should be considered; and
- Who else should be engaged in the consultation process.

NEXTBRIDGE INFRASTRUCTURE

# East-West Tie Transmission Project Overview

NextBridge proposes to construct an approximately 400 km, 230 kilovolt, double-circuit AC electrical transmission line extending from the existing Hydro One Networks Inc. (Hydro One) Lakehead Transformer Station in the Municipality of Shuniah near Thunder Bay to the existing Hydro One Wawa Transformer Station near Wawa – with a connection at the Marathon Transformer Station.

The Reference Route generally parallels an existing Hydro One transmission line corridor and has been identified as a potential route for the East-West Tie Project. The Reference Route Alternatives include possible route alternatives to avoid potentially sensitive features.




NEXTBRIDGE INFRASTRUCTURE

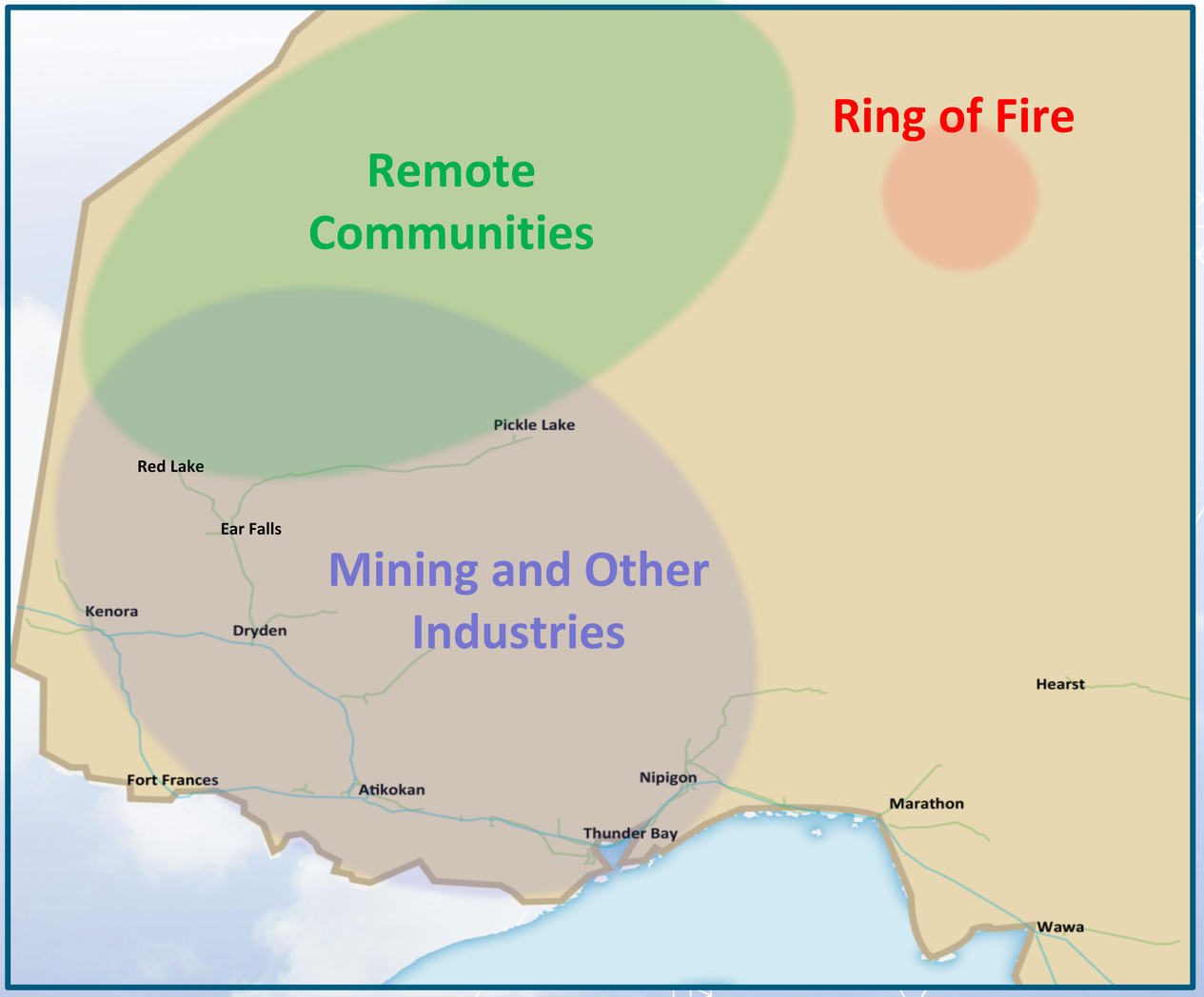
# East-West Tie Transmission Project Overview

- Project would also involve associated support facilities such as new and improved access roads, and laydown areas (temporary storage areas for equipment and supplies).
- Transformer station upgrades to Hydro One Networks Inc.'s infrastructure will be required.
- The new line will be owned and operated by NextBridge Infrastructure.
- The new line, in conjunction with the existing line, is anticipated to provide a total transfer capability of 650 MW into the Northwest, while respecting all applicable reliability standards.
- Targeted in-service date for the new line is the first half of 2018.
- The project requires *Environmental Assessment Act* approval from the Ministry of the Environment and Leave to Construct approval from the Ontario Energy Board.

NEXTBRIDGE INFRASTRUCTURE

# The Changing Landscape for Electricity Planning in Ontario's Northwest

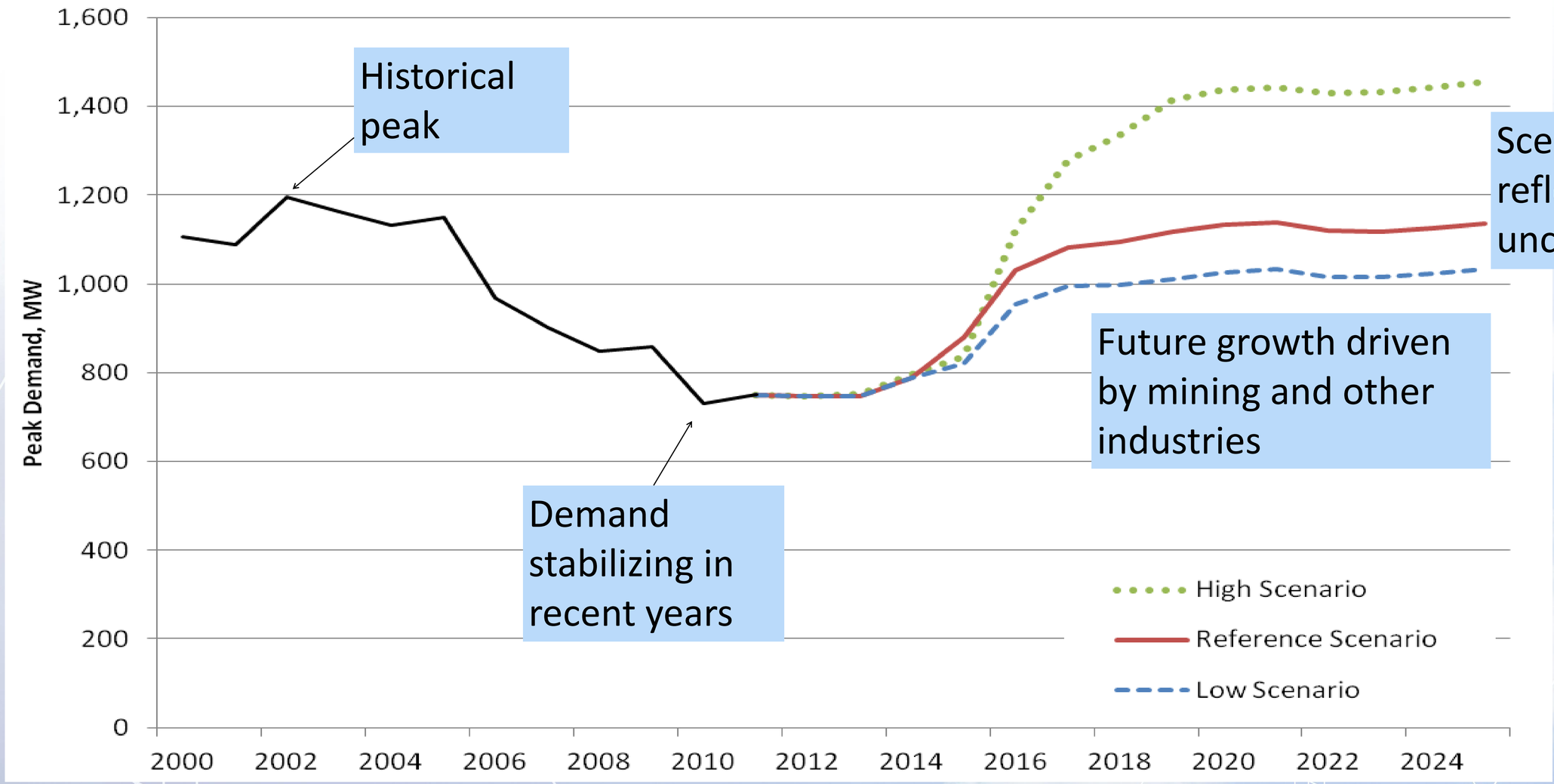
- Stretching from Marathon to Manitoba, and from Minnesota to Hudson Bay, Northwestern Ontario is a vast area with unique characteristics.
- Outlook for strong growth in the mining industry.
- Revitalization of pulp & paper, forestry, and other industrial sectors.
- Connection of remote communities.




Source: Ontario Power Authority

NEXTBRIDGE INFRASTRUCTURE

# Strong Demand Growth Forecast in the Northwest




**At the same time, the region's electricity supply situation is changing.**

Source: Ontario Power Authority

NEXTBRIDGE INFRASTRUCTURE

# Options to Meet the Northwest's Supply Need

Source: Ontario Power Authority

| | Transmission | Generation |
|---|---|---|
| Provides electricity supply for the Northwest | ✓ | ✓ |
| Provides supply to the rest of Ontario | ✓ | ✓ |
| Cost-effective | ✓ | |
| Improves system flexibility | ✓ | |
| Allows more efficient use of system | ✓ | |

- The OPA recommends proceeding with transmission: the East-West Tie expansion.
- Additional resources can be committed in step with demand growth as it materializes, and can be utilized more effectively with the expanded Tie.

# Scope of the East-West Tie Expansion Project

- The expansion involves building a new double-circuit 230 kV line from Wawa to Thunder Bay (approximately 400 km). It will also connect to the Marathon transformer station.
- Upgrades at the existing Wawa, Marathon and Lakehead transformer stations will also be undertaken.

- The new line, in conjunction with the existing tie, will provide a total transfer capability of 650 MW into the Northwest, while respecting all applicable reliability standards.
- The new line is expected to be completed in early 2018.

Source: Ontario Power Authority

NEXTBRIDGE INFRASTRUCTURE

# Transmission Development Process

## Planning

**Activities:**
- Load forecasting
- Need identification
- Alternative analysis
- System studies
- Policy alignment

## Project Development

**Activities:**
- East-West Tie Designation Process
- First Nations, Métis, and Stakeholder Engagement
- Environmental Assessment
- Preliminary engineering
- Routing and siting
- Detailed cost estimates

## Approval

**Activities:**
- Leave to Construct (Section 92) approval
- Environmental Assessment approval
- Other approvals as required

## Construction

**Activities:**
- Construction of transmission line and station facilities
- Commissioning

**Key Participants**

| | | | |
|---|---|---|---|
| *OPA , IESO and Ministry of Energy* | *OEB, OPA, IESO, NextBridge Infrastructure, and Hydro One Networks* | *OEB, OPA, IESO, NextBridge Infrastructure, and Hydro One Networks* | *NextBridge Infrastructure and Hydro One Networks* |

**2010** — **2018**

*OPA = Ontario Power Authority*
*OEB = Ontario Energy Board*
*IESO = Independent Electricity System Operator*

NEXTBRIDGE INFRASTRUCTURE

*Source:* Ontario Power Authority

# Who is NextBridge?

## *Three strong partners in the energy sector*

**NextEra Energy Canada** is a wholly-owned subsidiary of NextEra Energy, Inc., a leading clean energy company with revenues of more than US$15.3 billion, more than 41,000 megawatts (MW) of generating capacity, and approximately 15,000 employees in 24 states and Canada. Florida Power & Light Company, another subsidiary of NextEra, serves approximately 4.6 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the United States.

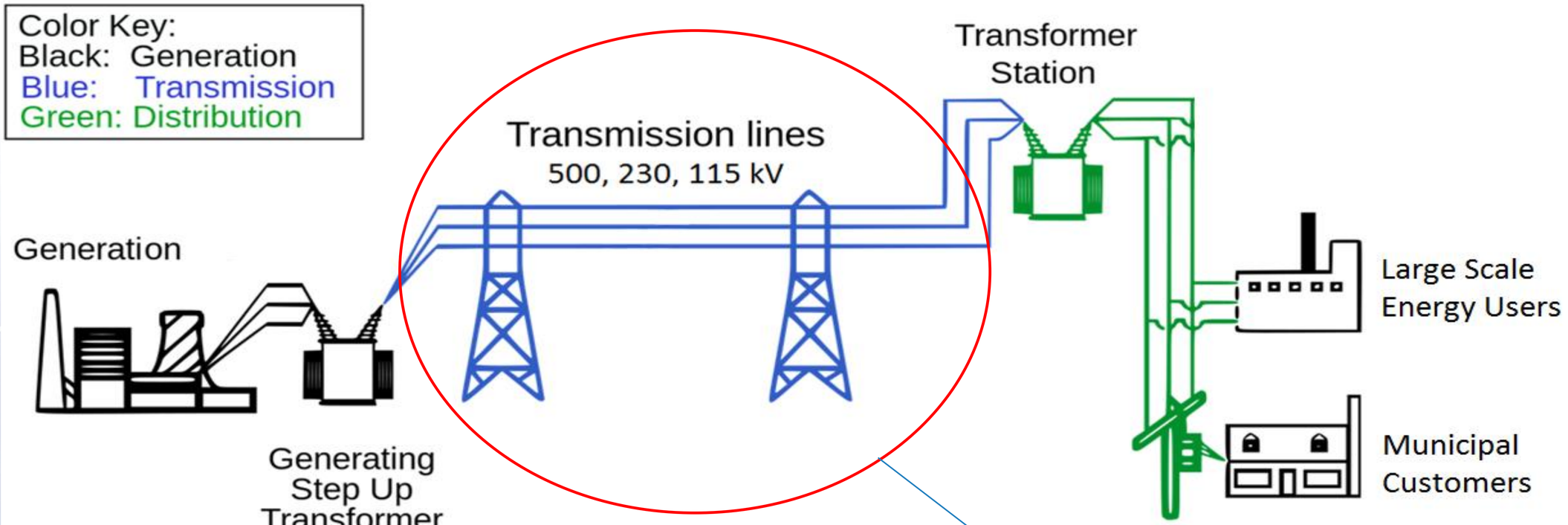
**Enbridge Inc.** is a North American leader in delivering energy, operating the world's longest crude oil and liquids transportation system, and has almost 1,000 MW of renewable and alternative energy generating capacity. Enbridge Inc. also owns the Montana-Alberta Tie-Line (MATL), a 300 MW, 230 kilovolt (kV) electrical transmission line allowing the movement of power between Alberta and Montana. Enbridge Inc. employs about 10,000 people, primarily in Canada and the U.S. and is ranked as one of Canada's Greenest Employers, and one of the Top 100 Companies to Work for in Canada.

**Borealis Infrastructure** is the infrastructure investment arm of the Ontario Municipal Employees Retirement System (OMERS), one of Canada's largest pension plans with approximately C$60 billion in net assets. Borealis ranks as one of the world's largest and most respected infrastructure investors with a proven track record in identifying, investing and actively managing large-scale infrastructure investments on behalf of OMERS.

NEXTBRIDGE INFRASTRUCTURE

# Transmission System Overview

Color Key:
Black: Generation
Blue: Transmission
Green: Distribution




***This is the role of the East-West Tie Project***

NEXTBRIDGE INFRASTRUCTURE

# Project Timeline

| | |
|---|---|
| 2010 | Ontario Power Authority identifies the project |
| 2011 | Minister of Energy asks the Ontario Energy Board to undertake a designation process to select a transmitter to develop the project |
| 2012 | Ontario Energy Board asks for bids to develop a new corridor in Ontario's northwest |
| August 2013 | NextBridge selected as the designated transmitter |
| 2013-2014 | Terms of Reference for Environmental Assessment |
| 2014-2015 | Environmental Assessment |
| 2014-2015 | Leave to Construct Application |
| 2016-2017 | Construction |
| 2018 | In Service |

NEXTBRIDGE INFRASTRUCTURE

# Environmental Assessment

**An Individual Environmental Assessment (EA) in accordance with the Ontario *Environmental Assessment Act* is required for this Project. An Individual EA is the most rigorous level of EA approval.**

**An Environmental Assessment is part of the formal approval process and is used to:**

- Predict and minimize or avoid environmental effects before they happen; and
- Incorporate environmental factors and public feedback into project design and decision-making.

**An Environmental Assessment includes:**

- A description of the project;
- A description of the existing natural, social, economic, and cultural environments (baseline studies);
- First Nations and Métis and stakeholder engagement to discuss and receive input on issues and concerns;
- Consideration of project alternatives, including advantages and disadvantages;
- Identification of possible environmental effects;
- Identification of measures to mitigate and manage identified potential environmental effects; and
- Recommendations for follow-up monitoring.

NEXTBRIDGE INFRASTRUCTURE

# The Environmental Assessment Process

## Overview of Environmental Assessment Process

We Are Here

### STEP 1
Terms of Reference

Prepare & Submit Terms of Reference Document

Government, First Nations, Métis, Stakeholder & Public Review of Terms of Reference

Decision

### STEP 2
Environmental Assessment Study

Prepare & Submit Environmental Assessment Document

Government, First Nations, Métis, Stakeholder & Public Review of Environmental Assessment

Final Decision

**CONSULTATION & ENGAGEMENT THROUGHOUT**

NEXTBRIDGE INFRASTRUCTURE

# Terms of Reference

The first step in the Environmental Assessment process is the preparation of the Terms of Reference. The Terms of Reference is a roadmap for the provincial Environmental Assessment process. It outlines how the Environmental Assessment will be conducted and how the public, First Nations and Métis communities, and government agencies will be involved.

**The Terms of Reference will describe:**

- **Basic project information and rationale for the project;**
- **Environmental Assessment, regulatory and other permit requirements;**
- **How the Environmental Assessment will be prepared;**
- **Purpose of the Environmental Assessment studies and the project;**
- **Description and rationale for the alternatives selection;**
- **A brief overview of the environment that the transmission line crosses;**
- **Engagement plan for the Environmental Assessment; and**
- **Flexibility to accommodate new circumstances.**

The Terms of Reference is subject to approval by the Minister of the Environment. Public, First Nation and Métis and other stakeholder input will be collected during the development of the Terms of Reference. There will be a formal public and agency comment period on the Terms of Reference.

NEXTBRIDGE INFRASTRUCTURE

# Process for the Terms of Reference

| | |
|---|---|
| Sep 2013 to Dec 2013 | Gather information about the study area |
| Dec 2013 | Hold public Open Houses to obtain feedback on the route and information about the study area as input to the Terms of Reference |
| Dec 2013 to Jan 2014 | Prepare the Terms of Reference |
| Feb 2014 | Terms of Reference submitted to the Minister of the Environment |
| Spring 2014 | Formal public, First Nations and Métis, and agency review of the Terms of Reference |
| Mid-2014 | Ministry of the Environment approval decision on the Terms of Reference |

# What's in the Terms of Reference:

## *A Description of the Proposed Project*

### ROUTING

- The Terms of Reference will describe the general characteristics of the Reference Route and alternative routes.
- NextBridge is looking at alternatives to the Reference Route in three areas (Pukaskwa National Park and two First Nations communities).
- Local refinements to the Reference Route may be identified to avoid potentially sensitive natural features.
- Public, stakeholder, agency and First Nations and Métis input will be sought out to help determine a preferred route in the areas where alternatives have been identified.

### RIGHT-OF-WAY AND TOWERS

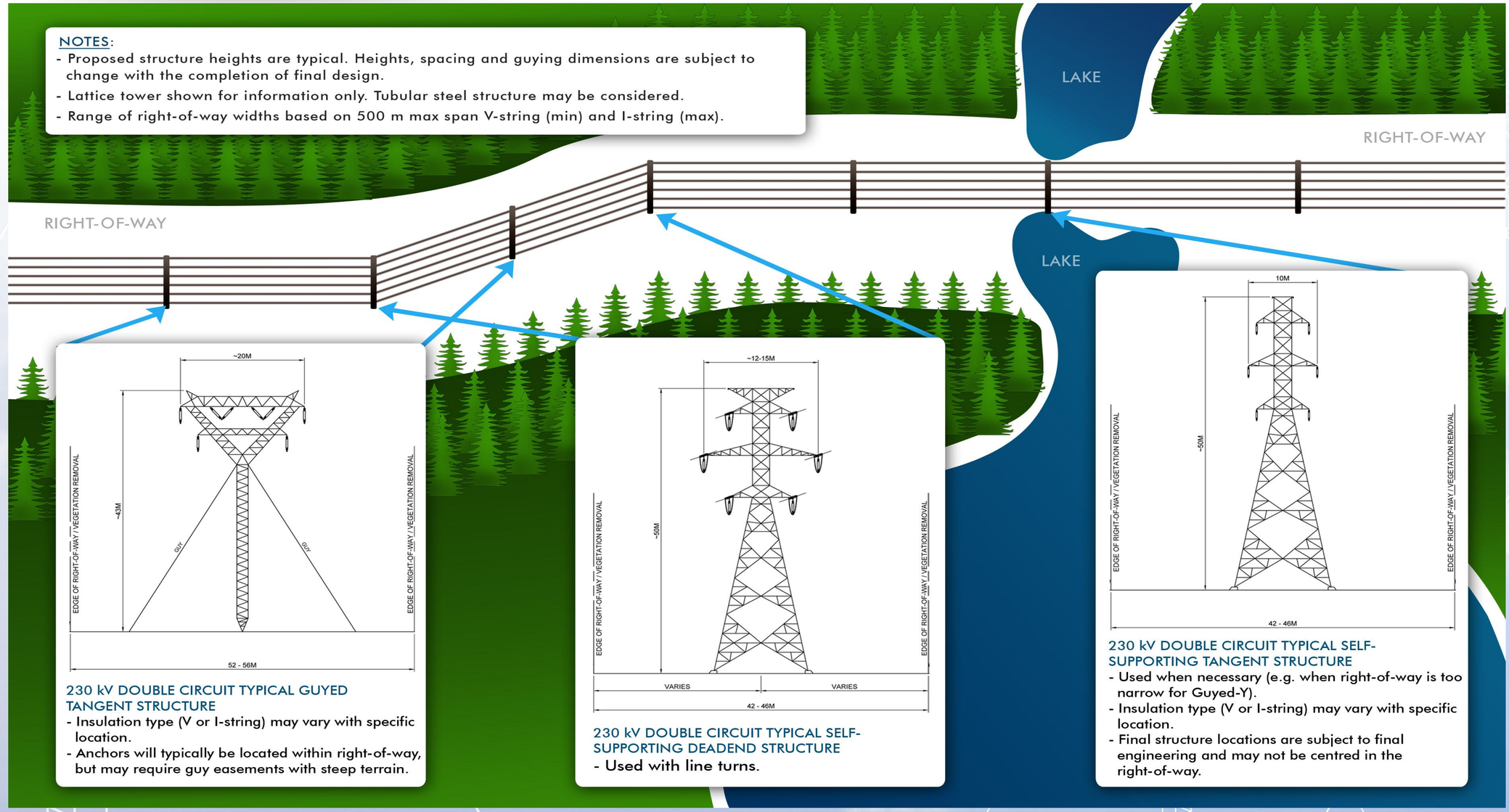
- A new right-of-way approximately 56 metres wide will be required.
- Structures will generally be centred in the new right of way and spaced approximately 400 metres apart.
- Generally tower structures may be "guyed-Y lattice structures". Self-supporting "tangent" and self-supporting "dead-end structures" may also be used.
- Public, stakeholder, agency and First Nations and Métis input will be sought on tower locations and structure types.

NEXTBRIDGE INFRASTRUCTURE

# What's in the Terms of Reference:

## *A Description of the Proposed Project*

NOTES:
- Proposed structure heights are typical. Heights, spacing and guying dimensions are subject to change with the completion of final design.
- Lattice tower shown for information only. Tubular steel structure may be considered.
- Range of right-of-way widths based on 500 m max span V-string (min) and I-string (max).







**230 kV DOUBLE CIRCUIT TYPICAL GUYED TANGENT STRUCTURE**
- Insulation type (V or I-string) may vary with specific location.
- Anchors will typically be located within right-of-way, but may require guy easements with steep terrain.




**230 kV DOUBLE CIRCUIT TYPICAL SELF-SUPPORTING DEADEND STRUCTURE**
- Used with line turns.




**230 kV DOUBLE CIRCUIT TYPICAL SELF-SUPPORTING TANGENT STRUCTURE**
- Used when necessary (e.g. when right-of-way is too narrow for Guyed-Y).
- Insulation type (V or I-string) may vary with specific location.
- Final structure locations are subject to final engineering and may not be centred in the right-of-way.

NEXTBRIDGE INFRASTRUCTURE

# What's in the Terms of Reference:

## *Route Selection Decision Process*

For the areas where alternative routes have been identified a preferred route needs to be selected. Decision-making under the *Environmental Assessment Act* must consider all aspects of the environment – natural, social, cultural and economic.

Criteria will be developed to help guide the selection of a preferred alternative.

Criteria will include, but will not be limited to, Species at Risk habitat, lakes and wetlands that cannot be spanned, private residences, hunt camps, and trap line cabins.

What do you think NextBridge should consider when making decisions on which route to use for the new East-West Tie?
**Please fill out a comment form and let us know**

NEXTBRIDGE INFRASTRUCTURE

Filed: 2020-11-04
EB-2020-0150
Exhibit A
Tab 4
Schedule 1
Attachment 1
Page 21 of 27

# What's in the Terms of Reference:

## *An Outline of Studies to be Completed*

The Terms of Reference will identify information to be collected during the Environmental Assessment. We plan to collect the following information by looking at background documents, speaking with First Nations and Métis communities, agency representatives and others and doing field work:

**NATURAL ENVIRONMENT**

- Fish and fish habitat;
- Forest resources;
- Significant valley lands;
- Significant wetlands;
- Species at Risk (e.g. Woodland Caribou);
- Water bodies; and
- Wildlife areas.

**SOCIAL, ECONOMIC AND CULTURAL ENVIRONMENT**

- Agriculture;
- Archaeology and heritage;
- Commercial activities (business activities close to right of way);
- Effect on properties;
- Land Use;
- Landscape and visual assessment (scenic views, aesthetics);
- Mineral and aggregate resources (pits and quarries);
- Recreational facilities (parks, trails);
- Social infrastructure and hard infrastructure; and
- Traditional First Nation and Métis knowledge.

This list of information may be refined as further input is received.

Information collected for the Reference Route and alternative routes (generally 500 metres on either side of the line route) will be mapped and used to:

- Characterize the area;
- Determine the potential impact of the project on the natural, social, economic, and cultural environments; and,
- Identify appropriate methods to minimize impact.

NEXTBRIDGE INFRASTRUCTURE

# Leave to Construct Approval

## Leave to Construct Approval (Section 92 of the *Ontario Energy Board Act, 1998*)

In order to build the new East-West Tie, NextBridge must file a “Leave to Construct” application with the Ontario Energy Board.

When the Ontario Energy Board receives a Leave to Construct application, it reviews the material, makes the information public and provides an opportunity for any interested parties, including First Nations and Métis communities, to provide input.

In carrying out its mandate, the Ontario Energy Board considers the impacts that the project may have upon consumers with respect to prices, as well as matters that concern the reliability and quality of electricity service.  The Ontario Energy Board will approve projects they consider to be in the public interest.

NextBridge is currently contacting landowners to arrange for access to property for field and legal surveys.

NEXTBRIDGE INFRASTRUCTURE

# NextBridge Infrastructure's Engagement Commitment

## COMMUNITY RELATIONS

NextBridge will engage stakeholders in any project it develops through honest, regular and open communication, seeking and respecting each party's input. We are committed to timely and meaningful dialogue with stakeholders, including governments, regulators, landowners, and interested members of the public, and believe that this input will be critical to a successful project that seeks to address the needs of those involved.

## FIRST NATIONS AND MÉTIS RELATIONS

NextBridge Infrastructure considers the participation of First Nations and Métis communities to be an essential component of successful transmission projects in Northern Ontario. NextBridge is committed to working with First Nations and Métis communities in Ontario to provide sustainable benefits to those communities.

NEXTBRIDGE INFRASTRUCTURE

# Consultation and Engagement

- NextBridge recognizes the importance of meaningful and respectful Stakeholder, First Nations and Métis engagement.
- We encourage participation at every step of this project.

During development of the Terms of Reference NextBridge has to date:

- Notified landowners along the Reference Route and alternatives and established contact;
- Developed a project contact list and notified elected officials, municipal staff, agencies and other key stakeholders;
- Placed ads in the local newspapers;
- Initiated discussions with First Nations and Métis;
- Held Open Houses;
- Prepared and distributed notices and newsletters; and
- Established a website and toll-free project hotline.

NEXTBRIDGE INFRASTRUCTURE

# Consultation and Engagement Activities

## Terms of Reference

- Municipal, agency & key stakeholder meetings
- Landowner contact by land agents
- First Nations & Métis meetings
- Notice of Commencement and Notice of Open Houses
- Newsletter #1
- Project hotline: 1-888-767-3006
- Project website: www.nextbridge.ca
- Open House round one – project introduction and the Terms of Reference
- Draft Terms of Reference 30-day comment period
- Notice of Submission of Terms of Reference to Ministry of the Environment
- Minimum 30-day public comment period on submitted Terms of Reference
- Notification of Minister's decision

## Environmental Assessment

- Notice of Commencement of Environmental Assessment
- Notice of Open Houses
- Continuation of municipal, key stakeholder, First Nations and Métis, agency, and landowner meetings
- Project hotline: 1-888-767-3006
- Project website: www.nextbridge.ca
- Additional newsletters
- Open House round two – alternative route evaluation and proposed mitigation measures
- Open House round three – Draft Environmental Assessment
- Draft Environmental Assessment 30-day comment period
- Notice of Submission of Environmental Assessment to Ministry of the Environment
- Minimum seven-week public comment period on submitted Environmental Assessment
- Posting of Ministry review of Environmental Assessment
- Notification of Minister's decision

NextBridge is available to respond to questions and discuss the project with interested parties throughout the Terms of Reference and Environmental Assessment process

NEXTBRIDGE INFRASTRUCTURE

# Electric and Magnetic Fields

- Electromagnetic Fields (EMFs; also called electric and magnetic fields) are invisible forces that surround electrical equipment, power cords, and power lines. You cannot see or feel EMFs.
- Every time you use electricity and electrical appliances, you are exposed to EMFs at extremely low frequencies (ELF). EMFs produced by both power lines and use of electrical appliances belong to this category.
- The levels of EMF drop off rapidly with distance from source.

## HEALTH CANADA'S POSITION ON EMFS

There is no compelling scientific evidence that EMFs in living and school environments, regardless of distance from transmission lines, cause ill health such as cancer.

Health Canada (2012) states:

*"When you are inside your home, the magnetic fields from high voltage power lines and transformer boxes are often weaker than those from household electrical appliances".*

Based on the available weight of evidence, Health Canada *"does not consider that any precautionary measures are needed regarding daily exposures to EMFs at ELFs. There is no conclusive evidence of any harm caused by exposures at levels found in Canadian homes and schools, including those located just outside the boundaries of power line corridors".*

NEXTBRIDGE INFRASTRUCTURE

# Thank You!

**On behalf of the project team,
thank you for attending this Open House.**

Please remember to fill out a comment form before you go.

## Input is always welcome:

Your input is important to us. If you have any questions or concerns, or if you require further information regarding this project, please contact:

**Oliver Romaniuk, Project Manager**
**NextBridge Infrastructure**
**Email: info@nextbridge.ca**
**Project Hotline: 1-888-767-3006**

Be sure to visit the project website for updates:

**www.nextbridge.ca**

NEXTBRIDGE INFRASTRUCTURE

# EXTERNAL LETTERS OF SUPPORT

# STAFF INTERROGATORY #53

## INTERROGATORY

Questions:

a) Please provide a status update on NextBridge's non-Indigenous consultation efforts.
b) Is NextBridge in receipt of any letters of support from non-Indigenous communities that have not been filed on the record, with respect to NextBridge's East-West Tie line project? If yes, please provide those letters.
c) Is NextBridge in receipt of any letters of opposition from non-Indigenous communities with respect to NextBridge's East-West Tie Line application? If yes, please provide those letters.

## RESPONSE

a) The most recent summary of non-Indigenous consultation activity is available in NextBridge's July 23, 2018 Report at pages 3-5. Non-Indigenous consultation since the July 2018 report has focused on landowners and other directly affected stakeholders, including municipalities.

   NextBridge continues to engage property owners with respect to the land rights required for all property interests affected by the proposed transmission line and related facilities. This includes private landowners and tenants, municipalities, provincial Crown agencies, federal Crown agencies, railway and other utility companies, and Crown land occupants such as mining claim and leaseholders and land use permit holders. In addition to maintaining an open and transparent dialogue with property owners with respect to land rights, NextBridge has been consulting over the last four-months with affected landowners and interest holders regarding ongoing pre-construction reconnaissance and environmental field studies occurring across the project area. This has included consultation with Crown land users such as bear outfitters or trappers to avoid disturbance to their activities as well as site meetings with representatives of affected recreational clubs to review the proposed project plans and address concerns and/or issues. Regular communication has also occurred with these stakeholders regarding project status. In March and May of 2018, in the spirit of maintaining open and respectful relations, NextBridge issued letters to affected property owners to provide an update on the project and status of associated Leave to Construct proceedings, including clarity on Hydro One's alternate project proposal and the impact to property interests.

For municipalities, a Project Update newsletter was distributed to Mayors and Chief Administrative Officers/Clerks of right of way municipalities on August 16, 2018 informing them of the recent decision to hold a joint hearing for the NextBridge EWT Line and the Hydro One Lake Superior Link Project and the desire for a commitment from the government identifying NextBridge as the project constructor in order to meet the 2020 in-service date.

Direct communication with municipalities has also continued on an as-needed basis. Additional engagement has occurred as a result of implementation of the community investment program. One of the benefits of the community investment program is it provides a touch point with municipalities during which other project items may be discussed.

b) Yes, NextBridge has received many letters of support for the project, some of which have been included in previous filings. A list of these letters follows, including references for where in the record the letters can be found. Those not currently on the record are attached to this response at Attachment 1.

- September 23, 2016 – Email from Municipality of Shuniah councilor thanking NextBridge for resolving their concerns and stating that the decision to select a refined route shows how community partnership can work effectively and collaboratively to solve problems. The councilor stated that they appreciate NextBridge's willingness to listen.
- September 27, 2016 – Email from East Loon Lake Campers' Association representative thanking NextBridge for revising the path of the EWT Line Project.
- May 8, 2017 – Township of Dorion letter to the Ministry of the Environment and Climate Change supporting the NextBridge project.
- September 19, 2017 – Letter from the Common Voice Northwest Energy Task Force (CVNW) to the Independent Electricity System Operator expressing their opinion that the Project is essential for the future of Northwestern Ontario.
- March 26, 2018 – City of Thunder Bay Committee of the Whole passed a resolution endorsing the CVNW Energy Task Force position supporting the NextBridge LTC (NextBridge April 20, 2018 Report at Schedule B).
- March 27, 2018 – Dorion letter of support to the MOECC (NextBridge April 20, 2018 report at Schedule C)
- April 23, 2018 – City of Thunder Bay Council ratified March 26, 2018 Committee of the Whole resolution endorsing the CVNW Energy Task Force positions supporting the NextBridge LTC (NextBridge July 23, 2018 Report at Schedule A).
- May 7, 2018 – Town of White River submitted a letter of support for the NextBridge LTC to the OEB noting NextBridge's commitment to consider the community's values. The Township further stated that they prefer the NextBridge proposal. (EB-2017-0182).

- August 16, 2018 – Email from City of Thunder Bay Mayor noting the City will continue to support NextBridge.
- August 20, 2018 – Letter of support from the Thunder Bay Chamber of Commerce to Minister of Energy, Mines, Northern Development and Indigenous Affairs.
- August 21, 2018 – Letter from Loon Lake camp owner to Hydro One indicating concerns for the Hydro One Terms of Reference and benefits of the NextBridge project.
- September 4, 2018 – Correspondence from East Loon Lake Campers' Association representative requesting intervenor status in LTC hearings and indicating support for the NextBridge project (EB-2017-0182).
- September 17, 2018 – Letter of support from the Thunder Bay Community Economic Development Commission to Minister of Energy, Northern Development and Mines and Indigenous Relations.
- September 17, 2018 – Letter of support from the Northwestern Ontario Municipal Association to Minster of Energy, Northern Development and Mines and Indigenous Relations.
- September 19, 2018 – Further letter of support from the Thunder Bay Chamber of Commerce to Minister of Energy, Northern Development and Mines and Indigenous Relations.
- September 21, 2018 – Letter of support from the City of Thunder Bay Office of the Mayor to Minister of Energy, Northern Development and Mines/Minister of Indigenous Relations.
- September 23, 2018 – Further letter of support from CVNW to Minister of Energy, Northern Development and Mines and Indigenous Relations.

c) Yes, NextBridge is in receipt of two letters that raised concerns about the EWT Line Project application. The letters are briefly summarized below and are attached to this response at Attachment 2. NextBridge does not consider the attached letters to necessarily be "opposition" letters, but, rather, expressions of concern and comment, which are expected as part of any engagement process. In all cases, NextBridge has worked with those communities that have expressed concerns.

- October 30, 2017 – NextBridge was copied on a letter from the Township of Dorion to the OEB. The Township is petitioning the OEB to require NextBridge to plan to provide annual financial payment for the location, construction, and operation of the Project to be located in the Township. NextBridge telephoned the Reeve of Dorion to better understand their concerns. Reeve noted they are in favour of the Project and are appreciative of NextBridge's efforts to accommodate their concerns during the development of the Project. The letter to the OEB was to inquire about payments to the township for ROW lands.

- November 15, 2017 – Letter from Municipality of Wawa reiterating belief that actions associated with the project do not support the "spirit and intent" of many of the guiding principles of the Growth Plan for Northern Ontario; frustration over the location of a SuperCom meeting the Municipality was invited to but was not reasonably close enough to the community to permit attendance; and an inability for the Municipality to participate as an intervenor given the Ontario Energy Boards decisions on the awarding of costs. In spite of these frustrations, the Municipality recognizes the ability of the project to benefit communities in Northern Ontario. NextBridge called and met with the Municipality of Wawa Chief Administrative Officer in April and May of 2018 to discuss concerns and presented a delegation at Wawa Council on May 1, 2018 to further discuss the project.

## Wu, Danni

**From:** Duff Stewart <dstewart@shuniah.org>
**Sent:** September-23-16 3:58 PM
**To:** Chris Lupaschuk
**Subject:** Re: Loon Lake Community Meeting Summary and Important EWT Project Update

Chris,

Thanks for all you help in resolving this.
It shows how community partnership can work effectively
and collaboratively to solve problems.
The willingness to listen was greatly appreciated.

Yours truly,

Duff Stewart
McTavish Councillor
in Shuniah Municipality

---

**From:** Chris Lupaschuk <Chris.Lupaschuk@enbridge.com>
**Sent:** September 23, 2016 3:59:11 PM
**Cc:** Chris Lupaschuk
**Subject:** Loon Lake Community Meeting Summary and Important EWT Project Update

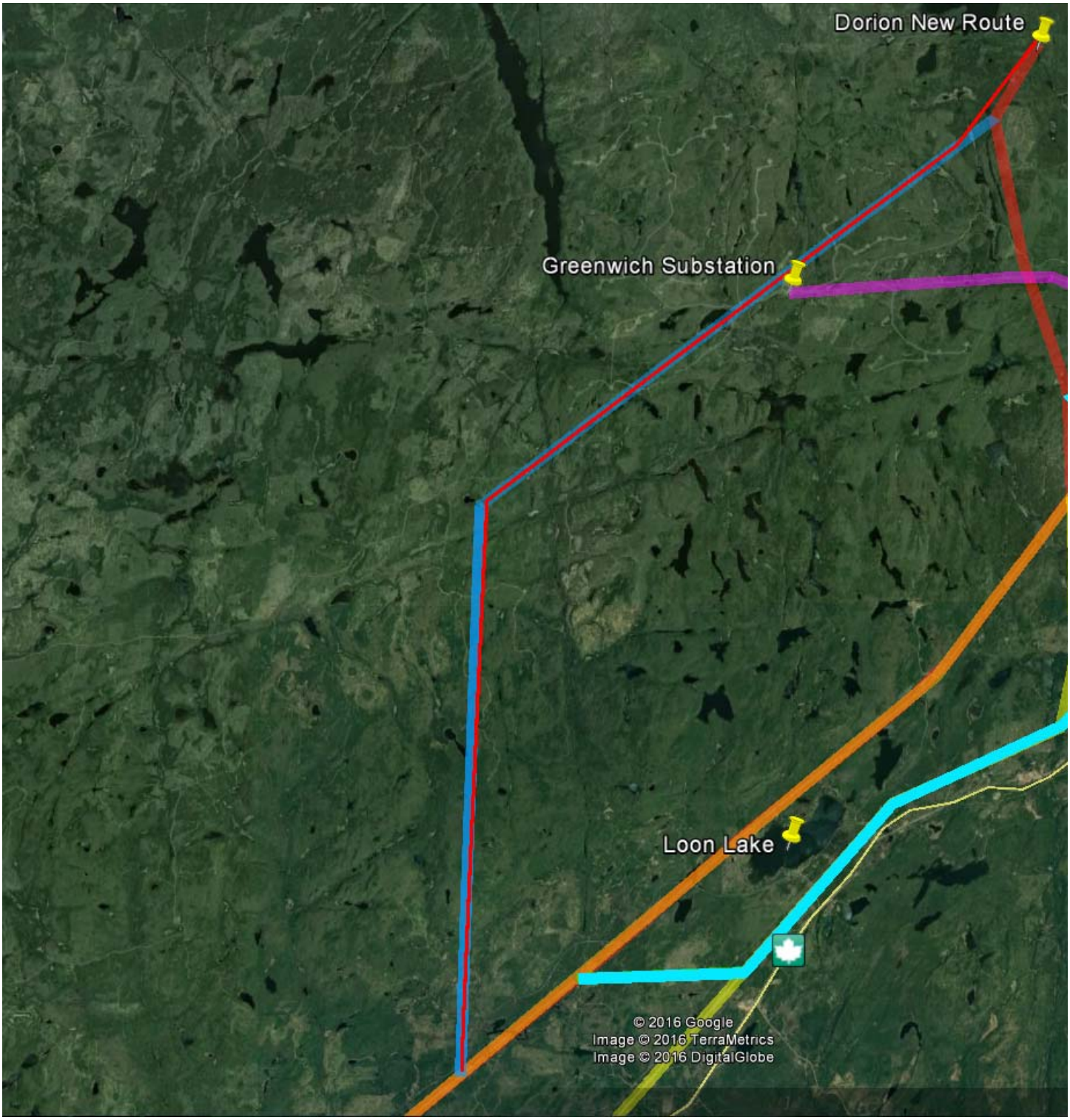
Dear Community Member,

Thank you for attending the community meeting related to the East-West Tie Transmission Project (the Project) which took place at the West Loon Lake Community Centre on July 26th, 2016.

As committed to attendees during the meeting, a draft summary was reviewed and comments were provided by members of the Loon Lake community and the North Shore Fishing Club prior to finalization and circulation to the rest of the attendees of the meeting. The summary has now been finalized, and is attached for your records.

**We also have an important update to share.**

In response to the suggestions and feedback received as part of the consultation activities with Loon Lake Community members and the North Shore Fishing Club, we have conducted routing assessments on the proposed routes brought forward by your community. After careful consideration and thorough review, NextBridge made refinements to the community-proposed northern route brought forward by the meeting attendees. The newly refined route incorporates elements of the feedback provided, and is illustrated below using a thin red line along with the three community-proposed routes.




To summarize, this new alternative, or Local Route Refinement, addresses many of the issues brought forward to NextBridge during our meeting and other stakeholder engagement and consultation activities throughout the development of the Project. NextBridge is now incorporating this Local Route Refinement into our project planning and our Environmental Assessment and therefore no longer considering the route generally paralleling the existing East-West Tie near Loon Lake.

As shown in the above map, the new Local Route Refinement relieves many of the concerns which have been brought forward. We believe this Local Route Refinement alleviates the need for building a list of action items and addressing additional follow-up commitments which were brought up during the Loon Lake Community Meeting. However, we are

still committed to providing this information if requested. We are also open to further discussion regarding the new Local Route Refinement, and are willing to attend another community meeting to present this update in-person, if requested.

I look forward to your feedback and continuing our dialogue. If you have any questions or comments, please feel free to reach out using any of the contact methods listed in my e-signature below.

We want to sincerely thank the Loon Lake community and North Shore Fishing Club for bringing your concerns forward, and for helping NextBridge develop the best route possible for the new East-West Tie Transmission Project.

Kind regards,

Chris Lupaschuk
Stakeholder Relations

NEXTBRIDGE INFRASTRUCTURE
TEL: 519-339-0524 | CELL: 226-402-2761
Western Research Park
1086 Modeland Road, Bldg. 1050, 1st Floor
Sarnia, ON N7S 6L2

www.nextbridge.ca

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## Wu, Danni

**From:** Zoie Yurick <zogo@shaw.ca>
**Sent:** September-27-16 3:18 AM
**To:** Chris Lupaschuk
**Subject:** Re: Loon Lake Community Meeting Summary and Important EWT Project Update

Dear Chris,

I apologize for my late reply. We are still getting into the groove of back to school and activities.

Thank you so much to you and your team for coming to us and hearing us. Thank you for deciding to revise the path of the EWT.

If you are ever in Thunder Bay please come to Loon for a swim and a sauna.

Thank you again,

Zoie Yurick
East Loon Campers Association

---

**From:** "Chris Lupaschuk" <Chris.Lupaschuk@enbridge.com>
**Cc:** "Chris Lupaschuk" <Chris.Lupaschuk@enbridge.com>
**Sent:** Friday, September 23, 2016 3:59:11 PM
**Subject:** Loon Lake Community Meeting Summary and Important EWT Project Update

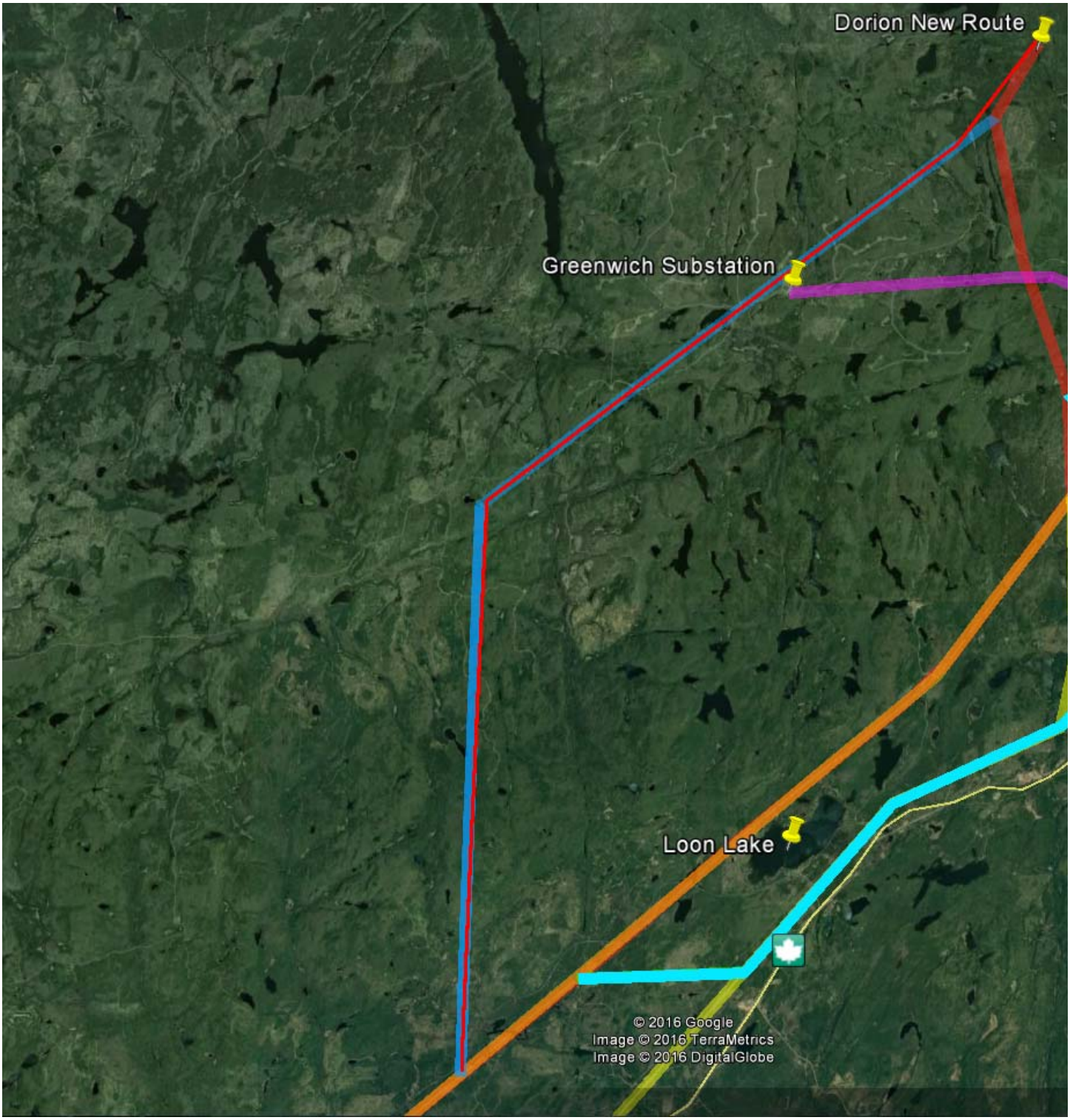
Dear Community Member,

Thank you for attending the community meeting related to the East-West Tie Transmission Project (the Project) which took place at the West Loon Lake Community Centre on July 26th, 2016.

As committed to attendees during the meeting, a draft summary was reviewed and comments were provided by members of the Loon Lake community and the North Shore Fishing Club prior to finalization and circulation to the rest of the attendees of the meeting. The summary has now been finalized, and is attached for your records.

**We also have an important update to share.**

In response to the suggestions and feedback received as part of the consultation activities with Loon Lake Community members and the North Shore Fishing Club, we have conducted routing assessments on the proposed routes brought forward by your community. After careful consideration and thorough review, NextBridge made refinements to the community-proposed northern route brought forward by the meeting attendees. The newly refined route incorporates elements of the feedback provided, and is illustrated below using a thin red line along with the three community-proposed routes.




To summarize, this new alternative, or Local Route Refinement, addresses many of the issues brought forward to NextBridge during our meeting and other stakeholder engagement and consultation activities throughout the development of the Project. NextBridge is now incorporating this Local Route Refinement into our project planning and our Environmental Assessment and therefore no longer considering the route generally paralleling the existing East-West Tie near Loon Lake.

As shown in the above map, the new Local Route Refinement relieves many of the concerns which have been brought forward. We believe this Local Route Refinement alleviates the need for building a list of action items and addressing additional follow-up commitments which were brought up during the Loon Lake Community Meeting. However, we are

still committed to providing this information if requested. We are also open to further discussion regarding the new Local Route Refinement, and are willing to attend another community meeting to present this update in-person, if requested.

I look forward to your feedback and continuing our dialogue. If you have any questions or comments, please feel free to reach out using any of the contact methods listed in my e-signature below.

We want to sincerely thank the Loon Lake community and North Shore Fishing Club for bringing your concerns forward, and for helping NextBridge develop the best route possible for the new East-West Tie Transmission Project.

Kind regards,

Chris Lupaschuk
Stakeholder Relations

NEXTBRIDGE INFRASTRUCTURE
TEL: 519-339-0524 | CELL: 226-402-2761
Western Research Park
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DORION TOWNSHIP
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May 8, 2017

Adam Wright, Special Project Officer, PCU
Ministry of the Environment and Climate Change
Environmental Approvals Branch
135 St. Claire Avenue West
Toronto, ON
M4V 1P5

Re: Letter of support for NextBridge and the East West Tie EA

Dear Sir,

The Township of Dorion wishes to write a letter of support for Nextbridge involving the East West transmission line that will pass through our community.

From the very beginning, Nextbridge has engaged our community and has been very open and transparent.

When we have asked for information, Nextbridge has responded in a timely manner.

Our community had concerns about the original proposed route and Nextbridge scheduled additional meetings to address these matters. Several alternatives were discussed and finally one was proposed that alleviates our concerns.

We continue to have open channels of communication and look forward to working with them through the EA approval process.

We anticipate a very good working relationship with NextBridge in the future.

Yours truly,

TOWNSHIP OF DORION

E.A. Chambers

Ed Chambers, Reeve

c.c. Jennifer Tidmarsh
Project Director East-West Tie Transmission Project

**Common Voice Northwest**
672 Churchill Place, Thunder Bay, ON P7C 5Y8
**Ph:** 1-(807) 474-0926 **Fax:** (807) 474-0881
**Email: iainangus@tbaytel.net**
**Chair:** Wendy Landry **Executive Director:** Iain Angus

Chuck Farmer
Director, Stakeholder & Public Affairs
Independent Electricity System Operator
1600-120 Adelaide Street West, Suite 1600,
Toronto, ON, M5H 1T1

September 19, 2017

RE: IESO Assessment of the East-West Tie Transmission Project

Dear Mr. Farmer

Further to our recent discussion the Common Voice Northwest Energy Task Force (CVNWETF or Energy Task Force) is pleased to provide the IESO with our perspective on the role that the East-West Tie Project will have on the future of Northwestern Ontario.

The Common Voice Northwest Energy Task Force is of the opinion that the proposed East-West Tie Project is essential for the future of Northwestern Ontario. Without it, existing industrial users will be disadvantaged while the number of new users will not proceed as investors look elsewhere for certainty. Our request to the IESO is to recommend to the Government of Ontario that the project should proceed as planned and that the Leave to Construct should be approved by the Ontario Energy Board.

We note that when the Order in Council (OIC) was issued on March 2, 2016 declaring that the East-West Tie Transmission Project "is needed as a priority project" it was clearly stated that "Ontario considers it necessary to expand Ontario's transmission system in order to maintain a reliable and cost-effective supply of electricity in the Province's Northwest, increase operational flexibility, reduce congestion payments and remove a barrier to resource development in the region". It is view of the region that little has changed since the OIC was issued.

We will outline in this letter the reasons why each of the criteria listed in the OIC continue to apply in 2017 and will most certainly apply in 2020 and beyond.

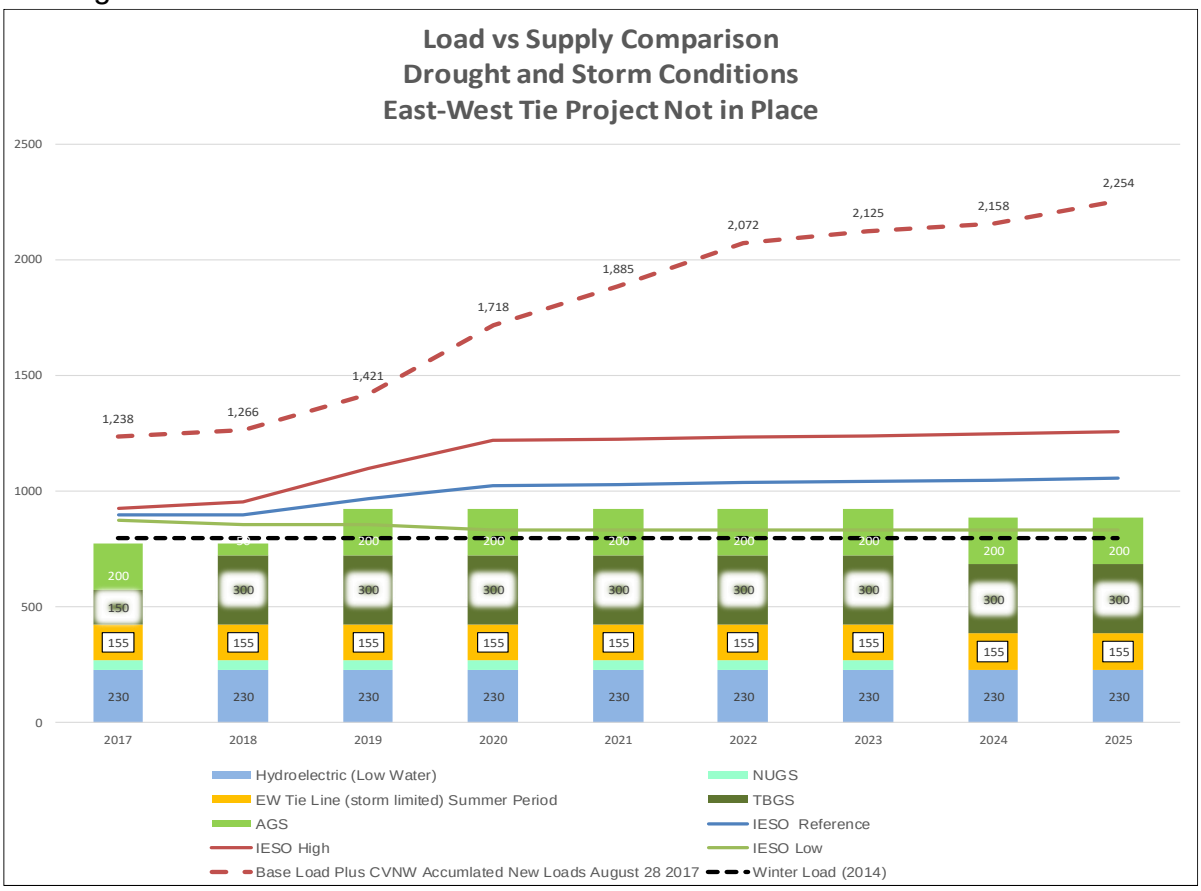
## 1. Reliability

As the IESO is aware, the Energy Task Force has been monitoring and identifying future load requirements in the Northwest and has regularly been sharing that information with the IESO and the Ministry. The Energy Task Force has also been analysing current supply and projected those needs into the future.

We define reliability as having a consistent, trouble free and adequate supply of electricity when and where it is needed.

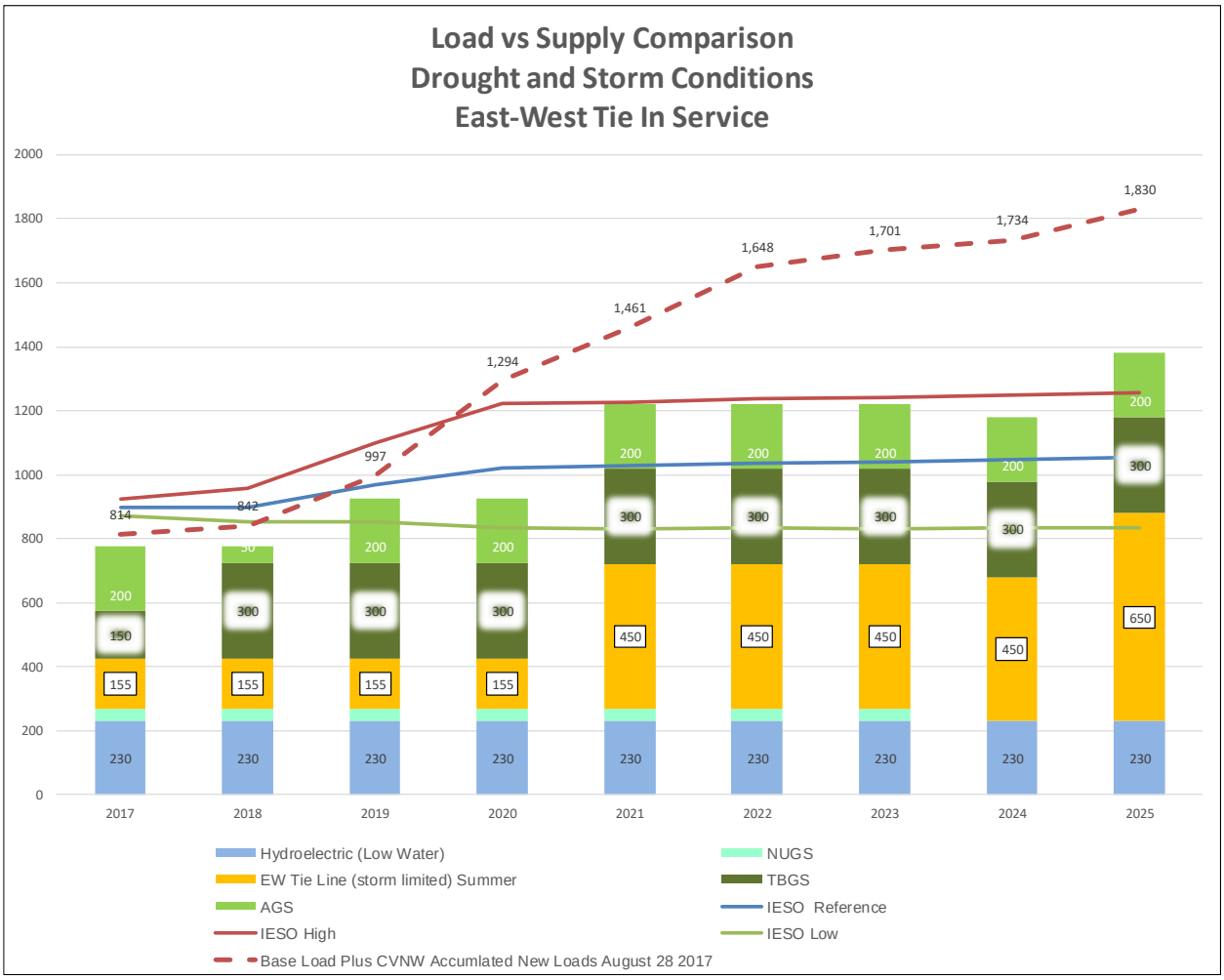
The existing East-West Tie that connects Northwestern Ontario via wires from Thunder Bay to Wawa to the Ontario Grid has a licensed capacity of 350 MW. Unfortunately, it is also located along the North Shore of Lake Superior, an area subject to an increasing number of electrical storms that require one half of the circuits to be taken out of service. That limits the transfer capacity to 155 MW during the summer, clearly affecting the reliability of the service. This combined with the ever-increasing number of droughts being experienced in the Northwest limits the region's ability to have a reliable power supply.

The following chart shows the impact on existing and future load requirements when the existing east-west tie is storm limited:



As the chart above indicates, with only 155 MW available to be brought into the Northwest through the existing East-West Tie during during summer electrical storms and drought conditions the hydroelectric power from the region will not meet even the IESO's minimum projected demand and both thermal generating stations would be required to run at or near capacity. None of the other projected levels, either by the IESO or CVNW Energy Task Force can be achieved without the East-West Tie Project.

The following chart shows the impact of the East-West Tie Project and the need for it to meet the needs of the region.[1]




The chart also provides an indication of the expected growth in the Northwest. The red dashed line is the culmination of the identified mining, forestry and industrial projects that are under planning or development with an indication as to the year(s) they are

[1] The line will initially operate at 450MW. The full 650 MW transfer capability will not be available until the SVC is installed (after a separate additional regulatory application process), currently estimated at 2024 or later (see IESO evidence filed as Attachment 2 to Exhibit B, Tab 4, Schedule 1 of NextBridge's LTC application).

expected to require electricity from the Ontario Grid. The three solid lines are the various projections the IESO has developed (High, Low and Reference.)

As can be observed, in every projected load requirement, except for the IESO Low, the full enhanced East-West Tie capacity is required[2] to meet the known needs of the Northwest.

In addition, post 2021, under the IESO scenarios the full capacity of the Thunder Bay Thermal Generation Station will be required with a portion of the output of the Atikokan GS as well. Under the Energy Task Force projections, the full capacity of both Generating Stations will be required as well as additional distributed generation. We estimate that the combination of existing drought on hydraulic generation, the enhanced East-West Tie and the two thermal generating stations will not meet the needs of the region by 2025. As a result the region will require an additional 430 MW of power.

## 2. Cost Effective Supply

Any discussion of the changes relative to Cost Effective Supply must be done in the context of the Ontario Energy Board's Phase 1 Decision and Order[3] of July 12, 2012 which outlines how estimates by the proponents should be prepared. The Order includes the following:

> "Regarding cost, the Board acknowledges, as several parties observed, that one of the purposes of the development work itself will be the estimation of construction and operation and maintenance costs, and that therefore applicants for designation will likely not be in a position to provide an accurate estimate of construction and operating and maintenance costs at the time of their application. Nevertheless, the Board finds that it must consider 5 all costs in assessing the merits of the various applications. Providing benefit to ratepayers through economic efficiency is a core objective in the Board's Policy, and the reasonableness of the total costs of the project will be a critical component in achieving that objective. The Board will therefore require that parties include in their applications an estimate of all costs, including those related to: preparation of an application for designation; development; construction; and operation and maintenance of the line.
>
> However, in recognition of the uncertainty inherent in estimating costs of construction and operation and maintenance of the line, the Board will accept these estimates expressed as a range. All the transmitters who have registered

[2] This assumes that the first full year of the East-West Tie in-service will be 2021.
[3] EB-2011-0140 Designation: East-West Tie Line Phase 1 Decision and Order

> their interest in the East-West Tie line project have, or have access to, experience in the construction of major infrastructure projects, and the Board expects that they will be able to create a reasonable estimated range for these costs, and provide justification for the cost estimates and width of the range. The Board will also require applicants to provide evidence of their plan to manage the costs of construction and operation and maintenance, and of their track record in estimating construction costs and keeping to those estimates. "

It was clearly the position of the OEB that it was early in the process for any of the possible proponents to provide a final price for the construction of the transmission line and that flexibility was expected. It is appropriate to note that the OEB expected the submitted price to change by the time that leave to construct was requested.

The decision by the Minister of Energy to request the IESO to "update its assessment on the basis of the latest costs" is founded on NextBridge's recent submission to the Ontario Energy Board in which they indicated that the estimated construction cost of the project is now $737 Million and the Minister's concern about "the new cost information".

NextBridge's original submission indicated that it expected to be able to build the line for $396.7Million Million and that included a type of tower that has not been used in the Northwest in the past and a line that went through Pukaskwa National Park. The proposal accepted by the OEB did not include equity positions by area First Nations. Prior to the OEB seeking proposals from companies interested in constructing the line, the Ontario Power Authority estimated that a traditional line would cost in the range of $600 Million.

When the Energy Task Force met with representatives of NextBridge on their first foray into the region, the Energy Task Force membership questioned the choice of towers as well as the distance between the so-called containment towers[4]. It was the articulated position of the Energy Task Force that the proposed towers would be subject to early failure and the cascading distance would ultimately render the East-West Tie out of service for a considerable period of time. The Energy Task Force noted the extreme weather that is experienced along the full length of the proposed transmission line and the susceptibility of the line to weather related failure.

The Energy Task Force also expressed concern over the lack of First Nation equity positions and warned the developer that the Indigenous communities would have to be accommodated. The Task Force also expressed doubt that the line would be allowed to go through the National Park.

[4] Designed to limit the extent of cascading in the event of a tower failure

It is clear that NextBridge heard the concerns and responded accordingly, thereby increasing the cost of the project. They and the Northwest should not be penalized for meeting the realities of the region.

In particular, the line is now 50 km greater than the original design resulting in about a 12.5% increase in the amount of steel required – and therefore the cost to construct.

In addition, it has been 5 years since NextBridge submitted their proposal and costing and according to the Bank of Canada Inflation Calculator costs have gone up 7.3%.

When these two increases alone are applied to the original OPA estimate of $600 million, the price rises to $720 million. The remaining $57 million can be accounted for by the economic participation of the 6 First Nations along with the further identification of the geological features and remoteness of some sections of the line.

### 3. Operational Flexibility

The current limitations on the East-West Tie, both in terms of capacity and the requirement for storm limitation restricts the ability of the grid to respond to the ongoing and future needs of the region.

As noted under 1 Reliability earlier in this letter, the current storm limitations applied to the existing East-West Tie can reduce the capacity of the line to 155 MW in the summer. This limits the flexibility for the system to respond to regular occurring droughts in the region which in turn will force industrial users to cease their operations. This will result in a loss of production and therefor profits for these operators. It also may lead to significant recovery expenses should the operational shut downs be unexpected.

### 4. Reduction of congestion payments

As the Energy Task Force understands “The region’s significant imbalance between abundant energy supply, modest demand, and insufficient transmission capacity and export opportunities has created surplus supply conditions in the area. This surplus supply has led to persisting gaps between nodal prices in the region – the prices that are intended to reflect the true cost of supplying electricity on a locational basis – and the province-wide uniform MCP. As the Panel has noted many times in the past, this pattern of prices drives inefficient market outcomes and creates gaming opportunities that cause inappropriate transfers of wealth which, in turn, raises the cost of energy for the province as a whole.”[5]

[5] Congestion Payments in Ontario’s Wholesale Electricity Market: An Argument for Market Reform, December 2016, Page 39

The OEB report[6] on page 49 reported that "Implementation of the October 2012 market rule change has eliminated the incentive for importers to chase nodal prices in the NW".

It is the position of the Energy Task Force that there is no further relationship between the East-West Tie and the reduction of congestion payments.

**5. Remove a Barrier to Resource Development**

The East-West Tie is an essential element to the Northwestern Ontario supply and its future economic wellbeing.

The existing radial lines to Red Lake, Pickle Lake and Greenstone are old, susceptible to interruption and are under capacity for the needs of those areas and the remote communities north of them.

The East-West Tie will ensure the availability of 650 MW of power that will be fed west and north from Thunder Bay and Nipigon. In particular, the Energy Task Force has identified the following additional sub-regional loads that will require servicing:

| | |
|---|---|
| North of Dryden | 174 MW |
| West of Thunder Bay | 258 MW |
| Greenstone-Marathon | 161 MW |
| Thunder Bay | 777 MW |
| Ring of Fire | 70 MW |

As noted in the following chart, there are 23 mines working their way through to development and operation

[6] IBID

| Mine | Location | Start Year | Circuit | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 12YEAR TOTAL | 2026 and BEYOND | GRAND TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Goldcorp Inc. -Cochenour Bruce Channel Deposit (5 | NoD | 2018 | | | 9 | | | | | | | | 9 | 5 | 14 |
| New Gold-Rainy R (3.8 M Oz Gold-9.4 M Oz Silver)(NW of F | WoTB | 2017 | | 61.2 | | | | | | | | | 61.2 | 3 | 64.2 |
| Harte Gold 319,280 oz @ 10.13 g/T Au(N of White River) | G-M | 2018 | | | 10 | | | | | | | | 10 | | 10 |
| Treasury Metals (1.14 M. oz Gold)(Dryden) | WoTB | 2019 | | | | 12 | | | | | | | 12 | | 12 |
| Zenyatta Ventures 1.5 m/t C measured and infered @4% Ca | G-M | 2019 | | | | 15 | | | | | | | 15 | | 15 |
| Pure Gold (Madsen Mine)(928,000oz Gold)(Red Lake) | NoD | 2019 | | | | 15 | | | | | | | 15 | | 15 |
| Greenstone Gold=Premier Gold Mines/Centerra Gold (4 | G-M | 2019 | | | | 46 | | | | | | | 46 | | 46 |
| First Mining Finance/PC Gold Inc. (1.26 M oz Gold | NoD | 2022 | | | | 10 | | | | | | | 10 | | 10 |
| Wesdome-Moss Lake Gold Project (1.1 Million oz Au @ 1.1g | WoTB | 2020 | | | | 40 | | | | | | | 40 | | 40 |
| Noront Resources (11 mt @ 2.5% Copper/Nickel) (R | RoF | 2022 | | | | | 20 | | | | | | 20 | | 20 |
| Frontier Lithium-Pakeagama Lake Lithium(7.89Mt @ 1.73% | NoD | 2022 | | | | | | | 10 | | | | 10 | 10 | 20 |
| Northern Iron (Griffith Iron Mine) (120 M t iro | NoD | unknown | | | | | | | | | | | 0 | | 0 |
| First Mine Finance-Cameron Lk (997,000oz. Gold) (SE of Ker | WoTB | 2023 | | | | | | | | 15 | | | 15 | 15 | 30 |
| Yamana/Agnico-Canadian Malarctic Partnership (5.13 M. ( | WoTB | 2023 | | | | | | | 100 | | | | 100 | 100 | 200 |
| Sibanye-Stillwater Canada Ltd. (91 M t- 1 g/t Palladium/ | G-M | 2025 | | | | | | | 50 | | | | 50 | 0 | 50 |
| First Mine Finance-Goldlund (2.41 M oz.gold)(S of S Lookou | WoTB | 2023 | | | | | | | | 10 | | | 10 | 0 | 10 |
| First Mine Finance/Gold Canyon Resources inc.( 4.41M oz) | NoD | 2022 | | | | | | | | | 30 | | 30 | 0 | 30 |
| Rio Tinto -Panoramic (10 Mt @2.2 g\t Platinum & Pal | TB | 2024 | | | | | | | | | | 30 | 30 | | |
| Rockex Mining Corp. (1 Billion t @ 25-30% Fe)(S. of S Lo | NoD | 2024 | | | | | | | | | | | | 100 | 100 |
| Ambershaw Metallics-Bending Lake Iron Corp. (245 M. t @ | WoTB | unknown | | | | | | | | | | | | 0 | 0 |
| Noront Resources (200 M t Chromite) (Ring of Fire) Black | RoF | 2017 | | 30 | | | | | | | | | | 0 | 0 |
| Rubicon Minerals Corp. (106,000 oz Gold) (Red Lake) | NoD | ? | | | | | 15 | | | | | | | 0 | 0 |
| Avalon Advanced Materials Inc.10 M t 2 1.3% Li O2(N of Kenora) | | | | | | | | | | | | | | | |
| TOTAL | | | | 91.2 | 19 | 138 | 35 | | 160 | | 30 | 30 | 483.2 | 233 | 716.2 |

along with 6 sawmill/pellet manufacturing facilities,

| FORESTRY LOADS | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Zone | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 12YEAR TOTAL | 2026 and BEYOND | GRAND TOTAL |
| Nakina Sawmill | | 2018 | | | 3.5 | | | | | | | | | | |
| Pellet Manufacturing Facilities (5 locations @3.5 MW ea) | | 2019 | | | | 12.25 | | | | | | | | | |
| FORESTRY LOADS TOTAL | | | | 0 | 3.5 | 12.25 | | | | | | | 0 | 0 | 0 |

up to 10 Energy East Pump Stations[7] and the possibility of 4 large industrial facilities being developed in or around the City of Thunder Bay. Electrical power is an essential ingredient to those loads being attracted to this region. Given the current state of the supply in the region, the above noted loads will not be met without the East-West Tie enhancement.

| INDUSTRIAL LOADS | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TransCanada Pipeline - 9 locations @ 10 MW each | | | | | | | 90.0 | | | | | | 90.0 | | 90.0 |
| Chromite Processor in Thunder Bay | | | | 347 | | | | | | | | | 347.0 | | 347.0 |
| Solar Manufacturing Facility in Thunder Bay | | | | | 5.0 | 5.0 | 50.0 | 100.0 | | | | | 160.0 | | 160.0 |
| Data Process Centre in Thunder Bay | | | | | | | 65.0 | 65.0 | | 50.0 | | | 180.0 | | 180.0 |
| Pharmaceutical Plant | | | | | | | | | 25.0 | | | | | | |
| TOTAL INDUSTRIAL LOADS | | | | 347.0 | 5.0 | 5.0 | 205.0 | 165.0 | 25.0 | 50.0 | | | 777.0 | | 777.0 |

The Northwest has also identified other reasons why the East-West Tie Transmission project should proceed as planned with the in-service date remaining 2020. The next four sections deal with those issues.

[7] At the time of writing TransCanada Pipelines has asked the NEB to suspend consideration of their application to enable TCP time to re-assess their plans given the new requirements of the NEB regarding Oil Sands Emissions. It is the position of CVNW ETF that a thirty-day hiatus is not an indication that the project is cancelled nor has the proposed time line changed. We would rather err on the side of caution than move the in-service dates to a future year.

## 6. Equity Participation by First Nations

NextBridge's original (and approved) submission did not include any costs related to First Nation and Metis land acquisition and participation costs by area First Nations even though the route traversed their traditional territories. Subsequently, NextBridge has been successful in negotiations with those First Nations to involve them in the project, both from an equity perspective (20%) as well as employment and contract services.

The following are the First Nations involved formally under the "BLP Group" (and managed by Supercom Industries): Fort William First Nation, Red Rock Indian Band, Pays Plat First Nation, Pic Mobert First Nation, Pic River First Nation and Michipicoten First Nation.

Negotiations are ongoing with the Métis Nation of Ontario (Superior North Shore Metis Council, Greenstone Metis Council and Thunder Bay Metis Council) for a partnership agreement that also contemplates contracting and economic opportunities.

Any decision to cancel the project will undermine the opportunities for economic development for these six communities and further exacerbate their relationships with the Ontario Government

## 7. Training Programs

Under the leadership of President, Ed Collins, and in collaboration with Confederation College and Anishinabek Employment and Training Services (AETS), Supercom have secured $9M to train 200 people from the 6 communities for construction of the East-West Tie Project, (to work with/for the awarded construction company for the project). Supercom estimates First Nation employment and required training will reach 658 personnel to be ready for the 2018(November)-2020(November) construction period. Training modules will include: foundational skills, semi-skilled, skilled pre-trades, and employment preparation.

In addition, Supercom has signed 14 joint venture agreements with Thunder Bay and Northwestern Ontario businesses, securing First Nation employment with the partnerships, as well as direct finances, all specifically aligned to the East-West Tie

All of the above are at risk should the East-West Tie Project is delayed or cancelled. Training must start almost immediately if the students are to be ready when construction starts.

## 8. Economic Development for the Region

The long-standing position of the CVNW Energy Task Force is that the provision of adequate and reliable electrical energy is a cornerstone of the future of Northwestern Ontario. Without an adequate and stable electrical supply, the Northwest will have minimal growth. With the right kind of power, in the right location, at the right time, the Northwest will become a mining power house, not just in Ontario but in North America.

The return to the Provincial treasury will far exceed the cost of constructing the East-West Tie, let alone all of the other transmission and generation improvements that the Energy Task Force has been seeking for nearly 10 years now.

## 9. Environmental Impacts

Should the Ontario Government choose to cancel the East-West Tie a number of mining developments will turn to diesel fuel, or natural gas, in order to supply their own power. It would appear that the first to take this step is Greenstone Gold Mines (Hardrock Mine) as the Ontario Government has failed to ensure that the transmission facilities to the Municipality of Greenstone and surrounding area, including a number of First Nations, are to be upgraded to meet the needs of the mine and the area. Instead of contributing a major part of the cost of upgrading the line, Greenstone Gold instead will be constructing their own dual cycle natural gas generator solely for their own use;not a regional solution!.

## Conclusion

**The Common Voice Northwest Energy Task Force is of the opinion that the proposed East-West Tie Project is essential for the future of Northwestern Ontario. Without it, existing industrial users will be disadvantaged while the number of new users will not proceed as investors look elsewhere for certainty. Our request to the IESO is to recommend to the Government of Ontario that the project should proceed as planned and that the Leave to Construct should be approved by the Ontario Energy Board.**

Yours truly

Jim Squire
Vice President
CVNW

**Copy to:**

Hon. Michael Gravelle, MPP, Minister of Northern Development and Mines

Hon Bill Mauro, MPP, Minister of Municipal Affairs

Hon Glenn Thibeault, Minister of Energy

Sarah Campbell, MPP

Northwestern Ontario Municipal Association

Northwestern Ontario Associated Chambers of Commerce

Union of Ontario Indians – Northern Superior Region

Nishnawbe Aski Nation

Grand Council Treaty 3

Fort William First Nation

Red Rock Indian Band,

Pays Plat First Nation

Pic Mobert First Nation

Pic River First Nation

Michipicoten First Nation.

Matawa First Nations Management

Wataynikaneyap Power

Hydro One Networks

Ontario Power Generation

**From:** Keith Hobbs
**To:** Brent Bullough
**Subject:** [External] Re: NextBridge East-West Tie - Summer Update and Request for Action
**Date:** Thursday, August 16, 2018 3:24:43 PM
**Attachments:** image001.png

---

Thanks Brent. Thunder Bay will definitely continue to support NextBridge and lobby for support.

Keith

Sent from my iPhone

On Aug 16, 2018, at 3:17 PM, Brent Bullough <Brent.Bullough@enbridge.com> wrote:

> Good Afternoon,
>
> I hope the summer has been treating you all well.
>
> I expect that some of you will be at the AMO conference in Ottawa in the coming days. Unfortunately, I won't be there so I want to take the opportunity now to provide you with some important information regarding the East-West Tie Project.
>
> As you may know, the Ontario Energy Board has scheduled a joint hearing in October to hear the NextBridge Leave to Construct as well as the Hydro One Leave to Construct. While it is good to have a hearing date scheduled, this timing continues to put the project at risk, particularly for a 2020 in-service date.
>
> Please review the attached project update and consider raising these issues and your concerns with your fellow elected officials. Send a message that this project is too important to be delayed and you support the NextBridge proposal.
>
> Thank you for your time and support.
>
> Sincerely,
> Brent
> Brent Bullough
> Advisor, Community Engagement
> <image001.png>
> TEL: 416-495-5339 | CELL: 647-280-4795
> 500 Consumers Road
> Toronto, ON M2J 1P8
> www.nextbridge.ca
>
> <AMO Update 16 August 2018_FNL.PDF>

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Thunder Bay Chamber of Commerce

stronger business together

August 20, 2018

Honourable Greg Rickford
Minister of Energy, Northern Development & Mines
Whitney Block Rm 5630
99 Wellesley St W
Toronto, ON M7A 1W1
Via email to Chief of Staff: Nina.Chiarelli@ontario.ca

Dear Minister Rickford:

ORDER IN COUNCIL: EAST-WEST TIE TRANSMISSION PROJECT

The new East-West Tie Transmission Project is vital to ensure the long-term reliability of the electricity supply in Northwestern Ontario. Two Independent Electricity System Operator (IESO) studies have confirmed the need for this line to be in place for 2020 to support industrial load growth.

Unfortunately, the Leave to Construct filing by NextBridge has been stalled at the Ontario Energy Board since July 2017. NextBridge has already invested more than $60 million in this project and has entered into agreements with multiple Indigenous communities to create meaningful participation opportunities, with the expectation that construction would start in the fall of 2018 as necessary to meet the 2020 in-service date. Almost 300 individuals from Indigenous communities in Northern Ontario have already been trained to support this work.

In order to proceed this fall, NextBridge requires a decision on the Leave to Construct; however, the Ontario Energy Board now indicates that they will not be discussing the project until a hearing in October 2018, which would not allow NextBridge to meet the 2020 in-service date. To ensure that construction can continue immediately so that the 2020 in-service date can be met, we offer our support of the request by NextBridge for an Order in Council identifying NextBridge as the project constructor by August 31, 2018.

Thank you for your consideration.

Sincerely,

Charla Robinson
President

c. Jennifer Tidmarsh, NextBridge Infrastructure, Jennifer.Tidmarsh@nexteraenergy.com

BERNARD LLP
BARRISTERS & SOLICITORS

Thomas F. Beasley
Direct No. 604-661-0617
Email: beasley@bernardllp.ca
File No. 051722 -0001

August 21, 2018
**By Email (community.relations@HydroOne.com)**

Community Relations
Hydro One
438 Bay Street
6th Floor
South Tower
Toronto, Ontario
M5G 2P5

Attn.: Melissa Fast, Community Relations Officer

Dear Ms. Fast:

**Re: Lake Superior Link Transmission Project**
- **Section 1: Thunder Bay to Nipigon**
- **Community Input: Loon Lake area**
- **Ontario Energy Board files: EB 2017-0182, 2017-0194 and 2017-0364**

Hydro One Networks Inc. ("Hydro One") and Upper Canada Transmission Inc. on behalf of NextBridge Infrastructure ("Nextbridge") have both applied to the Ontario Energy Board ("OEB"), under s. 92 of the *Ontario Energy Board Act,* S.O. 1998, c. 15 (the "*OEBA*") for leave to construct an electrical transmission line between Thunder Bay and Wawa, Ontario, commonly called the "East-West Tie line" (the "EWT line").

On August 13, 2018, the OEB combined the applications into a joint hearing at the OEB's Toronto office beginning on October 2, 2018.

Your recent public notice requested stakeholder input on the draft August 3, 2018 Terms of Reference by August 21, 2018.

## A. Stakeholder Status

**1.** I am a stakeholder with a keen interest in the Project. My wife, Victoria Donoghue and I own a camp (Northern Ontario term for cottage) at Loon Lake, Municipality of Shuniah, about 25 miles east of Thunder Bay. Our property is close to the Section 1 portion of that transmission line. My parents bought the property in 1959.



BERNARD LLP IS A PARTNERSHIP OF LAW CORPORATIONS

TEL: 604.681.1700 FAX: 604.681.1788 ADDRESS: 1500-570 Granville Street, Vancouver, BC, Canada, V6C 3P1 WEBSITE: www.bernardllp.ca

**2.** I am an employment law and administrative law lawyer in Vancouver, BC. and previously was called to the Ontario Bar.

**3.** We are members of the East Loon Lake Campers' Association Inc. ("ELLCA") which has conducted a vast array of summer programs and represented the property owners on the eastern half of Loon Lake, for over 40 years.

**4.** The proposed route of the Hydro One's application is close to Loon Lake, and in particular to the eastern portion where our property is located.

**B. Input on the draft Terms of Reference**

**5.** Safe reliable, sustainable and affordable electrical energy delivered in the most environmentally sensitive manner is in the best interests of all consumers.

**6.** The Ontario Energy Board ("OEB") must determine under s. 96 (2) of the *OEBA* whether the "the construction, expansion or reinforcement of the electricity transmission line or electricity distribution line, or the making of the interconnection, is in the public interest" with respect to:

1. The interests of consumers with respect to prices and the reliability and quality of electricity service.
2. Where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources. 2009, c. 12, Sched. D, s. 16.

**7.** Stakeholder input in advance of the hearing is vital to a good and responsive decision by the OEB on the 'public interest' portion of the EWT line applications.

**8.** In June 2018, Hydro One issued Terms of Reference ("Hydro One TOR") and sought stakeholder input by August 21, 2018.

**9.** The Hydro One TOR shows that the proposed project line runs alongside of the existing Transmission Line near Loon Lake.

**10.** I have 4 areas of concern on the Hydro One proposal:

**a)** Environmental impacts;

**b)** Viewscape impacts;

**c)** Noise and construction vehicle impacts on the East Loon road; and

**d)** Prior stakeholder input to Nextbridge.

**a) Environmental Impacts**

**11.** The impact of construction and of the subsequent vegetation control, including the impact of pesticide use on the fragile ecosystems (flora and fauna) of this area are the centre of those concerns.

**12.** As a beekeeper, I have seen dramatically the impact of pesticides on our bee colonies.

**13.** Loon Lake is primarily fed by aquifers and underground streams. Two creeks flow into Loon Lake, both run across the proposed EWT line in the Hydro One TOR.

**14.** Loon Lake and its adjacent watershed is the home of many sloughs and lakes for migrating birds which funnel up Black Bay. The Dorion Canyon Bird Festival, which draws birders to the area over the May long weekend, is based on that unique bird flow. That Festival just celebrated its 10th anniversary, see: http://www.dorionbirdfest.ca/.

**15.** Bats frequent the Loon Lake area. Bats are sensitive to construction, noise and disturbance of landscape. The near-by Cavern Lake Provincial Park is the home to caves with 4 species of bats. The caves are the largest known Precambrian caves in Ontario and possibly in Canada. See: https://www.ontarioparks.com/park/cavernlake

**16.** I have not seen any studies by Hydro One into the environmental impacts of the construction in the Section One area of the EWT Line.

**17.** Please email me a copy of Hydro One's environmental studies for the Loon Lake area of Section One, including the adjacent lands in the Municipality of Shuniah and Dorion Township, for:

**a)** Birds;
**b)** Animals;
**c)** Bats;
**d)** Fish; and
**e)** Stream and aquifers.

**18.** What is the:

**a)** proposed area of the parallel Transmission Lines near Loon Lake, including the right of way and the cleared right of way?; and

**b)** the vegetation control plan for those right of ways?

**b) Viewscape impacts**

**19.** Transmission lines create a scar on the landscape.

**20.** This negatively impacts the tourist and recreational use of the adjacent area.

**21.** My understanding is that the Hydro One TOR proposes a transmission line which can be seen from the shores and waters of Loon Lake.

**22.** That will significantly reduce the tourist and recreational value for the area residents and recreational users.

**23.** Please email me a copy of the Hydro One Viewscape studies of the proposed transmission line from the shores and waters of Loon Lake.

**c) Noise and Construction Impacts on the East Loon road**

**24.** The East Loon road is a quiet dead-end service road for the camp owners and residents.

**25.** The road is frequented by children, and has a 30km zone near the ELLCA Park facilities.

**26.** Please send me a copy of Hydro One's plans for using construction vehicles on the East Loon Road.

**27.** What is the location for Hydro One's construction headquarters for Section One and in particular for the Loon Lake area?

**d) Prior Stakeholder Input to NextBridge**

**28.** On July 31, 2017, NextBridge filed its Application for leave to construct the EWT line. That application followed months of public consultation and stakeholder input. Following extensive public input from area residents and other stakeholders, Nextbridge moved the EWT line to the next valley north of Loon Lake primarily so that:

**a)** The clear-cut and tower lines of the EWT line would not be visible from the shores and waters of Loon Lake; and

**b)** The environmental impacts on the Loon Lake watershed would be minimized.

**29.** In contrast, the Hydro One TOR gives very little time for stakeholder input.

**30.** With respect to the Loon Lake area, the Hydro One TOR is contrary to the Nextbridge decision following stakeholder input.

**31.** Hydro One must follow the same construction path north of Loon Lake, which Nextbridge chose to follow, after extensive stakeholder input.

**32.** To do otherwise is unseemly and unfair – fairness is at the heart of any administrative law process, including where to build the EWT line after receiving extensive public input.

**33.** The public interest demands that the EWT line be moved to the same location north of Loon Lake, as in the NextBridge application.

**34.** I will seek intervenor status at the hearing.

Yours truly,

BERNARD LLP

Per:

Thomas F. Beasley

C: East Loon Lake Campers Association, Attn.: William Goodman, President and Zoie Yurick, Secretary (by email)
NextBridge, Attn. Jennifer Tidmarsh, Project Director (by email)

noma
Northwestern Ontario Municipal Association

Representing the Districts of Kenora, Rainy River and Thunder Bay
P.O. Box 10308, Thunder Bay, ON P7B 6T8
www.noma.on.ca

p. 807.683.6662 e. admin@noma.on.ca

September 17, 2018

The Honourable Greg Rickford
Minister of Energy, Northern Development and Mines and Indigenous Relations
5th Floor - Whitney Block, 99 Wellesley Street West
Toronto, Ontario M7A 1W1

Dear Minister Rickford,

As you know, the Northwestern Ontario Municipal Association (NOMA) represents municipalities throughout the region from Kenora to Dubeuilville, Fort Frances to Greenstone and virtually all municipalities in-between. In keeping with the objectives of our Association, we are taking a strong and united stand on our support for the Nextbridge East-West Tie Project.

We are especially concerned that having been awarded the project in 2013 by the Ontario Energy Board in an open, fair and transparent process, a challenge to Nextbridge is soon to be considered by the same Board in response to a request from Ontario Hydro.

Nextbridge has spent the last 5-years and a considerable amount of capital developing this project to the point that they are only waiting on a long delayed Leave To Construct approval from the same board.

This project is poised to bring many benefits to the region in terms of economic activity, procurement, Indigenous involvement coupled with the fact that it will bring 650 MW of reliable electricity to the region that will be depending upon it for economic growth founded upon clean energy.

The Ring of Fire showed much promise but got mired in regulatory issues and remains idle. The same cannot be allowed to happen to the Nextbridge project. We cannot continue to treat the private sector in that manner and expect to claim Ontario is a great place to invest.

We urge you to take whatever measures you may have at your disposal to make this project a reality and allow Nextbridge to do what it does best, build a project that will benefit the northwest many times over. Let the fall construction begin.

Sincerely,

David Canfield
Past President

cc Rosemary LeClair, Ontario Energy Board

THUNDER BAY CEDC
COMMUNITY ECONOMIC DEVELOPMENT COMMISSION

P.O. Box 800
Suite 201, 34 Cumberland St. N.
Thunder Bay, ON Canada
P7C 5K4

Phone: 807.625.3960
Toll Free: 1.800.668.9360
Fax: 807.623.3962
develop@thunderbay.ca

September 17, 2018

The Honourable Greg Rickford
Minister of Energy, Northern Development and Mines and Indigenous Relations
5th Floor - Whitney Block
99 Wellesley Street West
Toronto, Ontario
M7A 1W1

Dear Minister Rickford:

The Thunder Bay Economic Development Commission has long been a champion of the East-West Tie Transmission project in Northwestern Ontario.

Our city and region needs access to reliable sources of electricity to attract business and in particular, those in the mining sector who require large amounts to power their operations.

Nextbridge, the project developer, has quite simply done a first rate job in reaching out to the Indigenous Community extending job opportunity and job training programs, to local businesses advising on procurement and supply chain opportunity, and to communities and their respective economic development commissions from Wawa to Thunder Bay on the issues and opportunities associated with this vital energy infrastructure.

As you know, Nextbridge's project is well advanced and has long been awaiting its final Leave to Construct approval from the OEB. Nextbridge and its Indigenous Partners have, for a very long period of time, been more than ready to start construction.

Our economic development commission is very concerned about any further delays and also of the Ontario Energy Board's highly unusual decision to now entertain a competing proposal that was rejected more than 5-years ago. Private sector investments must have a clear regulatory path to 'yes.' More red tape and deliberation is not what this project needs.

We strongly urge you and your government to use whatever means you have available to fast track the Nextbridge proposal. Jobs, investment and credibility of our regulatory processes are at stake.

Thank you for your attention to this matter.

Sincerely,

T. Douglas Murray, P.Eng.
CEO, Thunder Bay CEDC

cc Aaron Silver, Director of Policy
Nina Chiarelli, (A) Chief of Staff
Rosemary Leclair, Ontario Energy Board

Thunder Bay Chamber of Commerce

**stronger business together**

September 19, 2018

The Honourable Greg Rickford
Minister of Energy, Northern Development and Mines and Indigenous Relations
5th Floor - Whitney Block
99 Wellesley Street West
Toronto, ON M7A 1W1
Via email: greg.rickford@pc.ola.org

Dear Minister Rickford:

On behalf of the Thunder Bay Chamber of Commerce, I am writing again to express our strong support for the Nextbridge East-West Tie Project.

The project is shovel ready with a well-trained labour force that includes a significant and welcomed Indigenous Community presence. Local businesses in Thunder Bay also welcome the project and are eager to participate in its supply chain activities, thanks to a proactive outreach program initiated by Nextbridge.

Long in the making, and at a very mature stage of approval, the EWT Project has all of the elements of success: reliable and dependable source of power to the region; widespread benefits within Thunder Bay and the region; support and participation of the Indigenous Communities; and, new investment and jobs in a part of Ontario that could use both. Furthermore, Nextbridge has already invested over $60 million to ensure that the project is ready to meet the 2020 in-service date.

What the project desperately needs now is immediate action. The never-ending review before the Ontario Energy Board cannot continue. As you know, the project has been long awaiting a decision on its Notice To Proceed; another hearing that goes back to the starting line in order to review who the project should be assigned to is simply not acceptable.

Please take any and all necessary steps at your disposal to allow the Nextbridge project to proceed. It is shovel ready and, by virtue of the wide spread support, is region-ready as well. The negative impacts on investor confidence in the regulatory process are too great to consider otherwise.

Thank you for your attention to this matter.

Sincerely,

Charla Robinson
President

c. Aaron Silver, Director of Policy, aaron.silver@ontario.ca
Nina Chiarelli, (A) Chief of Staff, nina.chiarelli@ontario.ca
Rosemary Leclair, Chair, Ontario Energy Board

CITY OF Thunder Bay
Superior by Nature

500 Donald Street East
Thunder Bay, ON P7E 5V3
www.thunderbay.ca

OFFICE OF THE MAYOR

Tel: (807) 625-3600
Fax (807) 623-1164

September 21, 2018

The Honourable Greg Rickford
Minister of Energy, Northern Development and Mines/ Minister of Indigenous Relations
5th Floor - Whitney Block
99 Wellesley Street West
Toronto, Ontario
M7A 1W1

Dear Minister Rickford:

The City of Thunder Bay (the City) would like to express its strong and positive support for the Nextbridge East-West Tie Project.

The Nextbridge project is shovel ready, enjoys widespread support throughout the region and in particular from Indigenous communities and local businesses, who both stand to gain significantly during the construction and operation of the infrastructure, let alone the 650 MW of power that would be delivered to a region that requires reliable energy to meet its current and future growth and economic needs.

This update and overview is worthy of repeating as we are deeply troubled over a regulatory process that in 2013 awards Nextbridge the project and then 5-years and over $60 million later, the same regulatory in 2018 decides to let Hydro One to come in and renew their failed 2013 bid for the project.

This is not an efficient, fair or appropriate process to follow.

In 2016, the Ontario Government deemed the project to be a 'priority' by way of an Order In Council (OIC). It has been well over one year since Nextbridge filed, in July 2017 for the final approval - Leave To Construct, a process that is to take no longer than 210 days.

As such, the City is recommending that the clarity of an OIC be used to ensure the project does proceed as originally planned and approved, and thus allow Nextbridge to start construction later this year.

Thank you for your attention towards this urgent matter.

Sincerely,

Keith P. Hobbs, Mayor
City of Thunder Bay

Joe Virdiramo, Chair
Inter-governmental Affairs Committee

.cc
Nina Chiarelli, (A) Chief of Staff, Ministry of Energy, Northern Development and Mines
Aaron Silver, Director, Policy, Ministry of Northern Development and Mines
Rosemary Leclair, Chair & Chief Executive Officer, Ontario Energy Board
Norm Gale, City Manager, City of Thunder Bay
Doug Murray, CEO, Thunder Bay Community Economic Development Commission
Iain Angus, Co-Chair, Common Voice Northwest Energy Task Force
Inter-governmental Affairs Committee, City of Thunder Bay

**Common Voice Northwest**
672 Churchill Place, Thunder Bay, ON P7C 5Y8
**Ph:** 1-(807) 474-0926 **Fax:** (807) 474-0881
**Email: iainangus@tbaytel.net**
**Chair:** Wendy Landry **Executive Director:** Iain Angus
**Energy Task Force**

September 23, 2018

The Honourable Greg Rickford
Minister of Energy, Northern Development and Mines and Indigenous Relations
5th Floor - Whitney Block
99 Wellesley Street West
Toronto, Ontario
M7A 1W1

Dear Minister Rickford:

Common Voice Northwest's mission is to coordinate and support the efforts of organizational and community leaders in addressing the common issues impacting Northwestern Ontario. Our vision is to have vibrant communities with growing opportunities and sustainable services for all people at all phases of life in Northwestern Ontario.

Given the importance of energy to the livelihood of the region much of our work is devoted to this subject.

It was and now more than ever, continues to be our conviction that the East-West Tie Project is vital for the future of Northwestern Ontario.

Given the advanced and mature state of approval, our request to you and your Government is to ensure the Nextbridge Project proceeds as planned and that you grant their Leave-To-Construct, by Order In Council if necessary, so that the project can proceed with construction activities this fall.

An OIC is in keeping with what was issued on March 2, 2016 declaring that the East-West Tie Project is a 'priority project' and would provide the clarity this project now needs.

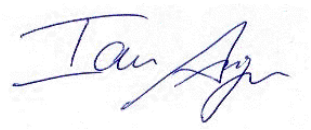
Rare is the time when a project enjoys such strong, positive and widespread support as does the Nextbridge project. Northwestern Ontario needs the energy to meet our needs and as a confidence builder for future economic development in the region. We see nothing but damage emerging from yet another round of regulatory review that questions the very premise of the awarding of the project to Nextbridge. We were all waiting for the long-delayed Leave To Construct to be issued, not to have the re-set button pushed and go back to basic project participants as that has long since been

settled. We must ensure our regulatory processes have clear paths to 'yes' — otherwise this process may never end.

We urge you to issue an Order In Council as soon as is possible to permit the Nextbridge Project to proceed with construction activity this fall.

Thank you in advance for considering our strong recommendation.

Sincerely



Iain Angus, Co-Chair
Energy Task Force

Larry Hebert, Co-Chair
Energy Task Force

cc Aaron Silver, Director of Policy, Office of the Honourable Greg Rickford
Nina Chiarelli, (A) Chief of Staff, Office of the Honourable Greg Rickford
Ms. Rosemarie Leclair, Chair, Ontario Energy Board

Attached: Copy of the remarks made to the Ontario Cabinet during the NOMA Briefing at AMO

**The following is the narrative that includes the key points raised with Cabinet by the City of Thunder Bay and NOMA at AMO**

In the City of Thunder Bay's presentation to the Parliamentary Assistant to the Minister of Energy, Northern Development and Mines and Indigenous Affairs and in NOMA's presentation to the full Ontario Cabinet, which included Minister Greg Rickford, it was noted that The Northwest is ready to boom! We have 23 mining projects underway (only 3 in the Ring of Fire) and that 12 are to be operational by 2020 (within the term of this government).

The Ontario Government was advised that the economic impact during the term of their government will be at a minimum $540 million in exploration investment, $2.2 Billion in construction costs and $2.7 Billion in operating revenue. It was also noted that the exploration and operating costs for the 5 remaining non-gold mines is unknown but will be significant. The GDP impact will range from $7 Billion to $10 Billion.

As a result of this economic activity, the Ontario Government will receive revenue between $740 million and $1 Billion over the next 5 years, not including the 5 non-gold mines and not including payments to Hydro One and OPG for massive amounts of electricity.

In order to ensure that this economic activity occurs the Northwest needs an assured supply of electricity. Key to this the construction of the East West Tie Line that will double the capacity of the Transmission facilities that bring power from North Eastern Ontario. The completion of that line by its approved and required in-service date of 2020 ensures that during drought conditions sufficient power is available in the Northwest.

Documents previously provided to the Ontario Government included a detailed description of why the east-west tie and other elements of the electrical system are required for the future.

*In the Thunder Bay and NOMA presentations to Cabinet during the week of August 20 the specific ask was to "**Issue an Order in Council by August 31, 2018 awarding the contract for the construction of the expanded East West Tie to Nextbridge,** the only company capable of getting the bulk transmission line in service by 2020 as required by the IESO"*

DORION TOWNSHIP
Canfocountry

170 Dorion Loop Road
Dorion, ON P0T 1K0

E – office @doriontownship.ca
P – 807-857-2289
F – 807-857-2203

October 30, 2017

Ontario Energy Board
2300 Yonge Street
Toronto,ON M4P 1E4

Re: Dorion Township Application to OEB Requesting an Oral Hearing and Intervenor Status

EB-2017-0182/EB-2017-0194

Dorion Township is a small community of 338 residents in Northwestern Ontario.
The Township is located about 80 kilometers east of Thunder Bay on Trans Canada Highway 11/17. It occupies about 212 square kilometres and has 154 households.

Presently, there are two (2) railways, one (1) natural gas pipeline, and four (4) high voltage electricity transmission lines traversing the Township.
The proposed East-West Tie Line Project would add a 5th major electricity transmission line through the Township.

The proposed route is through private property and is expected to involve lease agreements between the proponent, Upper Canada Transmission Inc, and the affected landowners.
The proposed development has involved substantial consultation with our residents, landowners, community representatives and Nextbridge Infrastructure Inc, the predecessor to UCTI.

*The railways, CNR and CPR, make annual payments in lieu of taxes to Dorion Township based upon their occupation of lands in the Township.*
*The Natural Gas Pipeline pays taxes to the Township for the lands occupied by their pipeline.*
*There is no payment from the Ontario or Canadian Governments for lands occupied by the TC Highway.*
*There are no payments from the owners of the electricity transmission lines and tower infrastructures occupying lands within the Township.*

Dorion Township landowners who have lease agreements with the previous owners (Ontario Hydro) of the four (4) current electricity transmission lines and towers received nominal one-time payments from Ontario Hydro.
Ontario Hydro and its successor Hydro One Networks Inc have not made any payment for construction, occupation and ongoing operation of existing electricity transmission lines and tower infrastructures.

...../2

*The East-West Tie Line Project proponent – Upper Canada Transmission Inc – is a private sector business corporation which proposes to plan, construct and operate the EWTL as a business venture for the profit of its' shareholders.*

Dorion Township expects to receive annual payments commensurate with the value of the capital cost infrastructure to be constructed and operated within Township boundaries comparable to the railway lines located in the Township.

Presently, there is no planned provision by UCTI to provide any payments to Dorion Township.

Dorion Township hereby petitions the OEB to require UCTI to plan for and provide annual financial payment for the location, construction, and operation of their business infrastructure to be located in Dorion Township.

Yours truly,

Ed Chambers, Reeve
Township of Dorion
R.R. #1,Dorion, ON **POT 1KO**

c.c. Hon. Glenn Thibeault, Ontario Minister of Energy

THE CORPORATION OF THE
MUNICIPALITY OF WAWA

**NextBridge Infrastructure**
**390 Bay Street, Suite 1720**
**Toronto, ON**
**M5H 2Y2**

**Via Email – info@nextbridge**

**November 15, 2017**

**Dear Sir / Madam:**

**Re: Leave to Construct – EB-2017-01 & EB-2017-0194**

We have received your letter dated October 18, 2017 regarding the above noted matters.

While we appreciate the receipt of this letter, we refer to previous correspondence from our Municipality that states among other things; the volume of material, short timeline and lack of staff capacity & expertise prevents us from participating to any meaningful level. In effect, we have been disenfranchised from our ability to partake in the process.

We had given some thought to participating as an intervenor, but unfortunately, recent decisions by the Ontario Energy Board on the awarding of costs have now prevented us from participating in this fashion.

While we continue to see in some ways, the ability of this project to benefit communities in Northern Ontario, it is also our opinion that the "spirt and intent" of many of the guiding principles in the Growth Plan for Northern Ontario are not supported by the actions associated with the proposed project.

Recently, we received an invitation to a session hosted by Supercom Industries that appears to promote training and employment for communities (assumably) along the East-West Corridor. It is worth noting that the session is occurring at the western section of the corridor (Nipigon) and as of the writing of this letter so such session is planned for the eastern section of the corridor – the drive from Wawa to Nipigon is five (5) hours.

2...

While it has been some time since we have heard from representatives of NextBridge, we do look forward to future discussions where we can more fully understand the dynamics of this project.

If you have any questions, please call.

**Best Regards,**

**Chris Wray, AMCT**
**CAO / Clerk-Treasurer**

Cc: Mayor and Council (email)
EDC of Wawa (email)
Ontario Energy Board (email)
Ministry of the Environment and Climate Change (email)
Ontario Growth Secretariat (email)

# FINANCIAL INFORMATION

1. NextBridge, as a newly formed partnership constructing its first transmission asset and revenue requirement proceeding has no regulatory financial results to reconcile with audited financial statements. However, included in this Exhibit as Attachments 3, 4, and 5 are the 2019 Annual Reports of NextEra Energy, Inc., Enbridge, and OMERS Administration Corporation. Also included are the following Historical Transmission Financial Statements from NextBridge:

   - Attachment 1: 2018 and 2019 Audited Financial Statements
   - Attachment 2: 2017 and 2018 Audited Financial Statements

2. The permanent financing for NextBridge is planned as a private placement which will require NextBridge to obtain a credit rating on a standalone basis. NextBridge will file the credit rating with the OEB upon receipt. The expected timing of the receipt of the credit rating is near the expected in-service date of March 31, 2022 for the East-West Tie line. Similarly, there are no prospectuses or information circulars related to debt financing, as the materials will be developed closer to the financing which is scheduled to occur until 2023.

**YEARS 2018-2019**

**YEARS 2017-2018**

# NEXTERA ENERGY INC., 2019 ANNUAL REPORT

NEXTera® ENERGY

ANNUAL REPORT **2019**

# UNITED STATES SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 10-K

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2019**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

| Commission File Number | Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number | IRS Employer Identification Number |
|---|---|---|
| 1-8841 | **NEXTERA ENERGY, INC.** | 59-2449419 |
| 2-27612 | **FLORIDA POWER & LIGHT COMPANY** | 59-0247775 |

700 Universe Boulevard
Juno Beach, Florida 33408
(561) 694-4000

**State or other jurisdiction of incorporation or organization**: Florida

**Securities registered pursuant to Section 12(b) of the Act**:

| Registrants | Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|---|
| **NextEra Energy, Inc.** | Common Stock, $0.01 Par Value | NEE | New York Stock Exchange |
| | 4.872% Corporate Units | NEE.PRO | New York Stock Exchange |
| **Florida Power & Light Company** | None | | |

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act of 1933.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

NextEra Energy, Inc. Yes ☐ No ☑ Florida Power & Light Company Yes ☐ No ☑

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark whether the registrants are a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company.

NextEra Energy, Inc. Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐
Florida Power & Light Company Large Accelerated Filer ☐ Accelerated Filer ☐ Non-Accelerated Filer ☑ Smaller Reporting Company ☐ Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Securities Exchange Act of 1934. ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity of NextEra Energy, Inc. held by non-affiliates at June 28, 2019 (based on the closing market price on the Composite Tape on June 28, 2019) was $97,905,404,884.

There was no voting or non-voting common equity of Florida Power & Light Company held by non-affiliates at June 28, 2019.

Number of shares of NextEra Energy, Inc. common stock, $0.01 par value, outstanding at January 31, 2020: 488,965,893

Number of shares of Florida Power & Light Company common stock, without par value, outstanding at January 31, 2020, all of which were held, beneficially and of record, by NextEra Energy, Inc.: 1,000

## DOCUMENTS INCORPORATED BY REFERENCE

Portions of NextEra Energy, Inc.'s Proxy Statement for the 2020 Annual Meeting of Shareholders are incorporated by reference in Part III hereof.

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This combined Form 10-K represents separate filings by NextEra Energy, Inc. and Florida Power & Light Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Florida Power & Light Company makes no representations as to the information relating to NextEra Energy, Inc.'s other operations.

Florida Power & Light Company meets the conditions set forth in General Instruction I.(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

## DEFINITIONS

Acronyms and defined terms used in the text include the following:

| Term | Meaning |
|---|---|
| AFUDC - equity | equity component of allowance for funds used during construction |
| AOCI | accumulated other comprehensive income |
| Bcf | billion cubic feet |
| CAISO | California Independent System Operator |
| capacity clause | capacity cost recovery clause, as established by the FPSC |
| DOE | U.S. Department of Energy |
| Duane Arnold | Duane Arnold Energy Center |
| environmental clause | environmental cost recovery clause |
| EPA | U.S. Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |
| FERC | U.S. Federal Energy Regulatory Commission |
| Florida Southeast Connection | Florida Southeast Connection, LLC, a wholly owned NextEra Energy Resources subsidiary |
| FPL | Florida Power & Light Company |
| FPSC | Florida Public Service Commission |
| fuel clause | fuel and purchased power cost recovery clause, as established by the FPSC |
| GAAP | generally accepted accounting principles in the U.S. |
| GHG | greenhouse gas(es) |
| Gulf Power | Gulf Power Company |
| ISO | independent system operator |
| ISO-NE | ISO New England Inc. |
| ITC | investment tax credit |
| kW | kilowatt |
| kWh | kilowatt-hour(s) |
| Management's Discussion | Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations |
| MISO | Midcontinent Independent System Operator |
| MMBtu | One million British thermal units |
| mortgage | mortgage and deed of trust dated as of January 1, 1944, from FPL to Deutsche Bank Trust Company Americas, as supplemented and amended |
| MW | megawatt(s) |
| MWh | megawatt-hour(s) |
| NEE | NextEra Energy, Inc. |
| NEECH | NextEra Energy Capital Holdings, Inc. |
| NEER | a segment comprised of NextEra Energy Resources and NEET |
| NEET | NextEra Energy Transmission, LLC |
| NEP | NextEra Energy Partners, LP |
| NEP OpCo | NextEra Energy Operating Partners, LP |
| NERC | North American Electric Reliability Corporation |
| net capacity | net ownership interest in pipeline(s) capacity |
| net generating capacity | net ownership interest in plant(s) capacity |
| net generation | net ownership interest in plant(s) generation |
| Note __ | Note __ to consolidated financial statements |
| NextEra Energy Resources | NextEra Energy Resources, LLC |
| NRC | U.S. Nuclear Regulatory Commission |
| NYISO | New York Independent System Operator |
| O&M expenses | other operations and maintenance expenses in the consolidated statements of income |
| OCI | other comprehensive income |
| OEB | Ontario Energy Board |
| OTC | over-the-counter |
| OTTI | other than temporary impairment |
| PJM | PJM Interconnection, L.L.C. |
| PMI | NextEra Energy Marketing, LLC |
| Point Beach | Point Beach Nuclear Power Plant |
| PTC | production tax credit |
| PUCT | Public Utility Commission of Texas |
| PV | photovoltaic |
| Recovery Act | The American Recovery and Reinvestment Act of 2009, as amended |
| regulatory ROE | return on common equity as determined for regulatory purposes |
| RPS | renewable portfolio standards |
| RTO | regional transmission organization |
| Sabal Trail | Sabal Trail Transmission, LLC, an entity in which a NextEra Energy Resources subsidiary has a 42.5% ownership interest |
| Seabrook | Seabrook Station |
| SEC | U.S. Securities and Exchange Commission |
| tax reform | Tax Cuts and Jobs Act |
| U.S. | United States of America |

NEE, FPL, NEECH, NextEra Energy Resources and NEET each has subsidiaries and affiliates with names that may include NextEra Energy, FPL, NextEra Energy Resources, NextEra Energy Transmission, NextEra, FPL Group, FPL Energy, FPLE, NEP and similar references. For convenience and simplicity, in this report the terms NEE, FPL, NEECH, NextEra Energy Resources, NEET and NEER are sometimes used as abbreviated references to specific subsidiaries, affiliates or groups of subsidiaries or affiliates. The precise meaning depends on the context.

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## FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, strategies, future events or performance (often, but not always, through the use of words or phrases such as may result, are expected to, will continue, is anticipated, believe, will, could, should, would, estimated, may, plan, potential, future, projection, goals, target, outlook, predict and intend or words of similar meaning) are not statements of historical facts and may be forward looking. Forward-looking statements involve estimates, assumptions and uncertainties. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, important factors included in Part I, Item 1A. Risk Factors (in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements) that could have a significant impact on NEE's and/or FPL's operations and financial results, and could cause NEE's and/or FPL's actual results to differ materially from those contained or implied in forward-looking statements made by or on behalf of NEE and/or FPL in this combined Form 10-K, in presentations, on their respective websites, in response to questions or otherwise.

Any forward-looking statement speaks only as of the date on which such statement is made, and NEE and FPL undertake no obligation to update any forward-looking statement to reflect events or circumstances, including, but not limited to, unanticipated events, after the date on which such statement is made, unless otherwise required by law. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained or implied in any forward-looking statement.

**PART I**

**Item 1. Business**

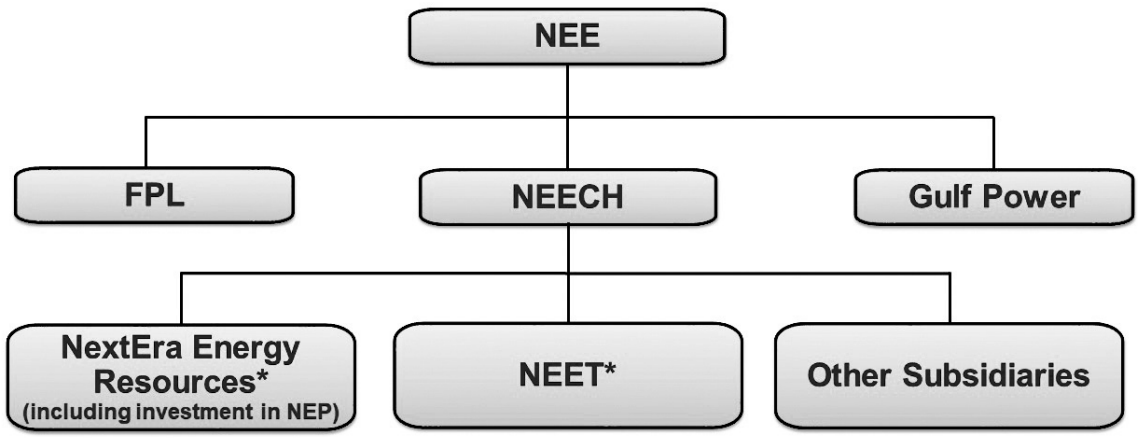
**OVERVIEW**

NEE is one of the largest electric power and energy infrastructure companies in North America and a leader in the renewable energy industry. NEE has two principal businesses, FPL and NEER. FPL is the largest electric utility in the state of Florida and one of the largest electric utilities in the U.S. FPL's strategic focus is centered on investing in generation, transmission and distribution facilities to continue to deliver on its value proposition of low bills, high reliability, outstanding customer service and clean energy solutions for the benefit of its more than five million customers. NEER is the world's largest generator of renewable energy from the wind and sun. NEER's strategic focus is centered on the development, construction and operation of long-term contracted assets throughout the U.S. and Canada, including renewable generation facilities, natural gas pipelines, electric transmission facilities and battery storage projects. In January 2019, NEE completed the acquisition of Gulf Power, a rate-regulated electric utility engaged in the generation, transmission, distribution and sale of electric energy in northwest Florida. See Gulf Power section below.

As described in more detail in the following sections, NEE seeks to create value in its two principal businesses by meeting its customers' needs more economically and more reliably than its competitors. NEE's strategy has resulted in profitable growth over sustained periods at both FPL and NEER. Management seeks to grow each business in a manner consistent with the varying opportunities available to it; however, management believes that the diversification and balance represented by FPL and NEER is a valuable characteristic of the enterprise and recognizes that each business contributes to NEE's financial strength in different ways. FPL and NEER share a common platform with the objective of lowering costs and creating efficiencies for their businesses. NEE and its subsidiaries continue to develop and implement enterprise-wide initiatives focused on improving productivity, process effectiveness and quality.

NEE, which employed approximately 14,800 people at December 31, 2019, was incorporated in 1984 under the laws of Florida. NEE's segments for financial reporting purposes are FPL, Gulf Power and NEER, which is comprised of two wholly owned subsidiaries of NEE that are combined for segment reporting purposes. NEECH, another wholly owned subsidiary of NEE, owns and provides funding for NEE's operating subsidiaries, other than FPL and its subsidiaries and Gulf Power. NEP, an affiliate of NextEra Energy Resources, was formed in 2014. NEP acquires, manages and owns contracted clean energy projects with stable, long-term cash flows. See NEER section below for further discussion of NEP, including changes to its governance structure, which resulted in the deconsolidation of NEP in January 2018.

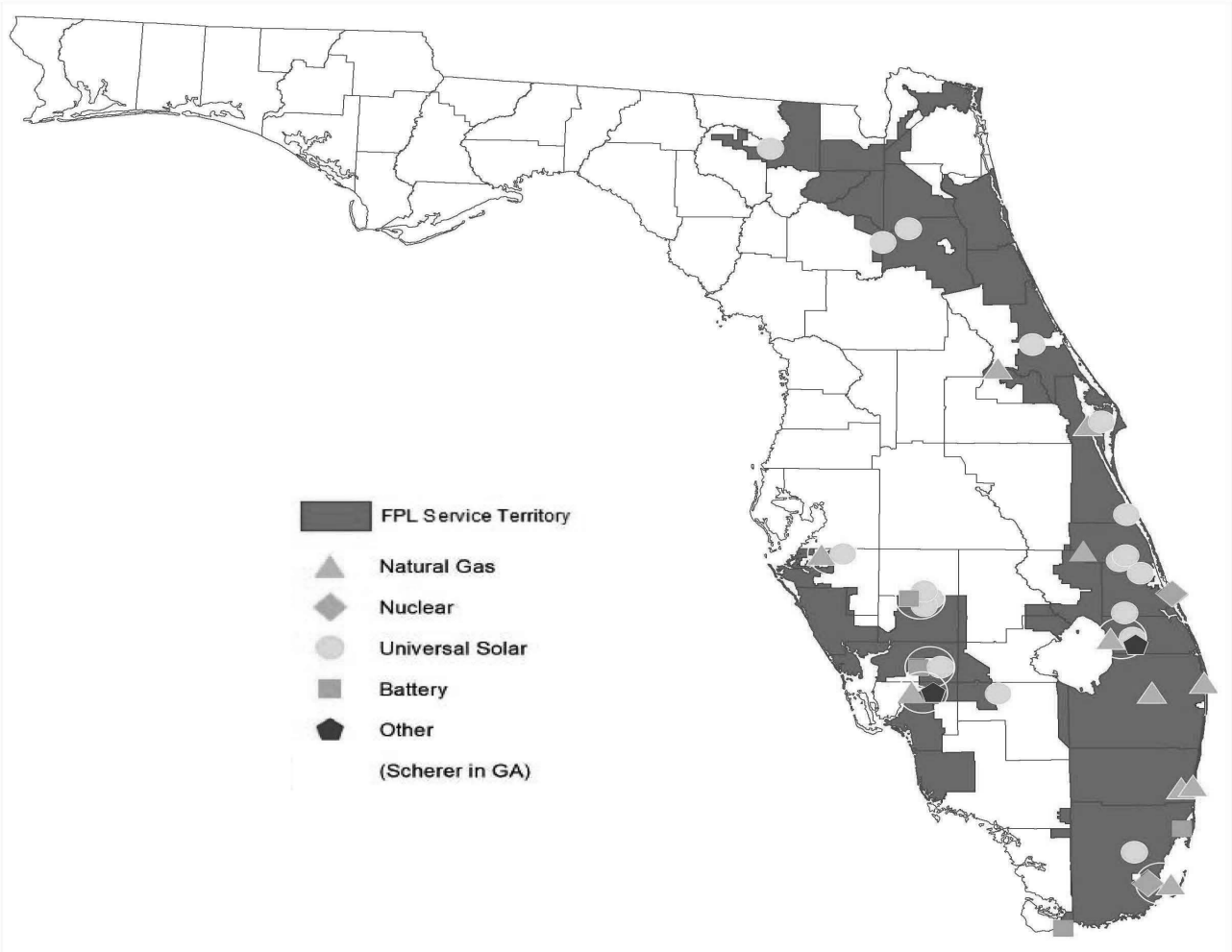
**NEE Organizational Chart**




* Comprises the NEER segment

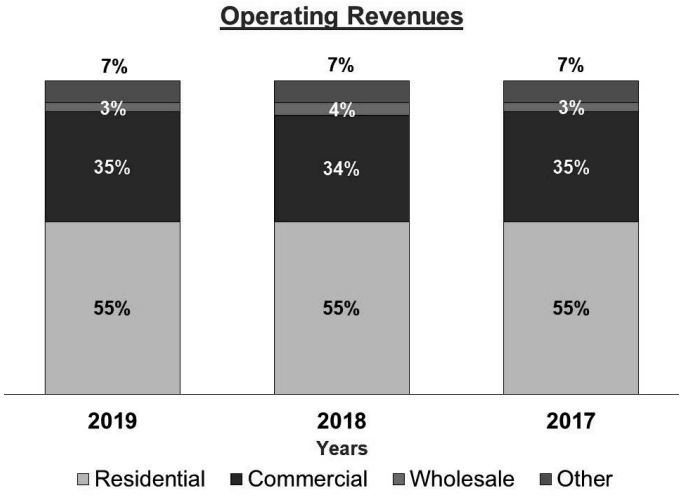
**FPL**

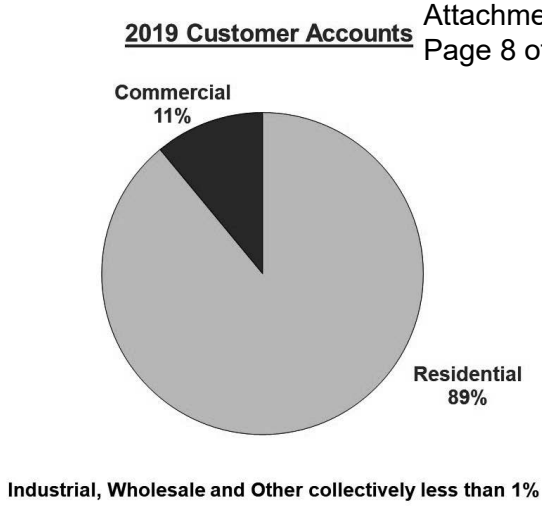
FPL was incorporated under the laws of Florida in 1925 and is a rate-regulated electric utility engaged primarily in the generation, transmission, distribution and sale of electric energy in Florida. In 2018, FPL acquired a retail gas business (see Note 8 - Other). FPL is the largest electric utility in the state of Florida and one of the largest electric utilities in the U.S. At December 31, 2019, FPL had approximately 27,400 MW of net generating capacity, approximately 75,400 circuit miles of transmission and distribution lines and 661 substations. FPL provides service to its electric customers through an integrated transmission and distribution system that links its generation facilities to its customers. At December 31, 2019, FPL served more than ten million people through more than five million customer accounts. FPL's service territory, which covers most of the east and lower west coasts of Florida, and plant locations at December 31, 2019 were as follows (see FPL Sources of Generation below):



## CUSTOMERS AND REVENUE

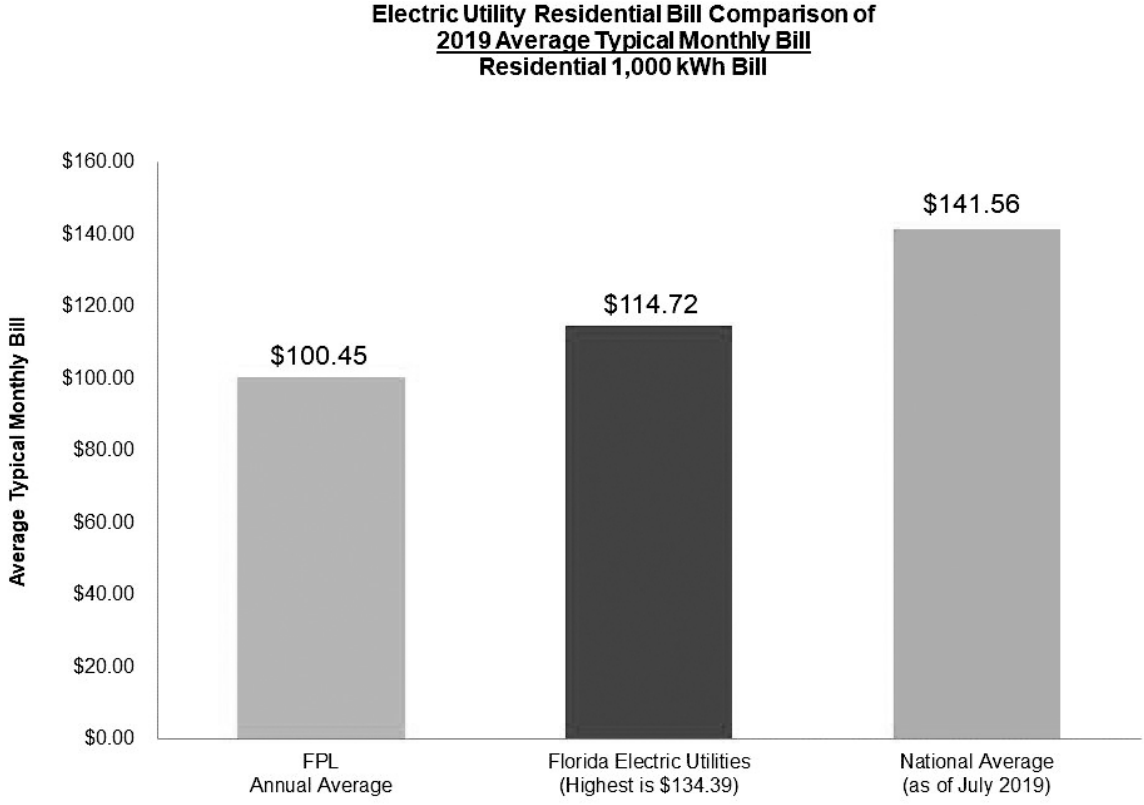
FPL's primary source of operating revenues is from its retail customer base; it also serves a limited number of wholesale customers within Florida. The percentage of FPL's operating revenues and customer accounts by customer class were as follows:




For both retail and wholesale customers, the prices (or rates) that FPL may charge are approved by regulatory bodies, by the FPSC in the case of retail customers and by the FERC in the case of wholesale customers. In general, under U.S. and Florida law, regulated rates are intended to cover the cost of providing service, including a reasonable rate of return on invested capital. Since the regulatory bodies have authority to determine the relevant cost of providing service and the appropriate rate of return on capital employed, there can be no guarantee that FPL will be able to earn any particular rate of return or recover all of its costs through regulated rates. See FPL Regulation below.

FPL seeks to maintain attractive rates for its customers. Since rates are largely cost-based, maintaining low rates requires a strategy focused on developing and maintaining a low-cost position, including the implementation of ideas generated from cost savings initiatives. A common benchmark used in the electric power industry for comparing rates across companies is the price of 1,000 kWh of consumption per month for a residential customer. FPL's 2019 average bill for 1,000 kWh of monthly residential usage was well below both the average of reporting electric utilities within Florida and the July 2019 national average (the latest date for which this data is available) as indicated below:



## FRANCHISE AGREEMENTS AND COMPETITION

FPL's service to its electric retail customers is provided primarily under franchise agreements negotiated with municipalities or counties. During the term of a franchise agreement, which is typically 30 years, the municipality or county agrees not to form its own utility, and FPL has the right to offer electric service to residents. FPL currently holds 184 franchise agreements with various municipalities and counties in Florida with varying expiration dates through 2049. These franchise agreements cover approximately 88% of FPL's retail customer base in Florida. FPL also provides service to customers in 11 other municipalities and to 22 unincorporated areas within its service area without franchise agreements pursuant to the general obligation to serve as a public utility. FPL relies upon Florida law for access to public rights of way.

Because any customer may elect to provide his/her own electric services, FPL effectively must compete for an individual customer's business. As a practical matter, few customers provide their own service at the present time since FPL's cost of service is lower than the cost of self-generation for the vast majority of customers. Changing technology, economic conditions and other factors could alter the favorable relative cost position that FPL currently enjoys; however, FPL seeks as a matter of strategy to ensure that it delivers superior value, in the form of low customer bills, high reliability and outstanding customer service.

In addition to self-generation by residential, commercial and industrial customers, FPL also faces competition from other suppliers of electrical energy to wholesale customers and from alternative energy sources. In each of 2019, 2018 and 2017, operating revenues from wholesale and industrial electric customers combined represented approximately five percent of FPL's total operating revenues.

For the building of new steam and solar generating capacity of 75 MW or greater, the FPSC requires investor-owned electric utilities, including FPL, to issue a request for proposal (RFP) except when the FPSC determines that an exception from the RFP process is in the public interest. The RFP process allows independent power producers and others to bid to supply the new generating capacity. If a bidder has the most cost-effective alternative, meets other criteria such as financial viability and demonstrates adequate expertise and experience in building and/or operating generating capacity of the type proposed, the investor-owned electric utility would seek to negotiate a purchased power agreement with the selected bidder and request that the FPSC approve the terms of the purchased power agreement and, if appropriate, provide the required authorization for the construction of the bidder's generating capacity.

## FPL SOURCES OF GENERATION

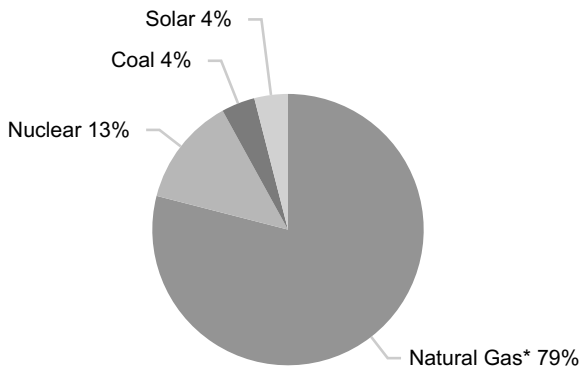
At December 31, 2019, FPL's resources for serving load consisted of approximately 27,554 MW, of which 27,440 MW were from FPL-owned facilities and 114 MW were available through purchased power agreements. FPL owned and operated 31 units that used fossil fuels, primarily natural gas, with generating capacity of 22,170 MW and had a joint ownership interest in 1 out-of-state coal unit, which it does not operate, with net generating capacity of 634 MW. In addition, FPL owned, or had undivided interests in, and operated, 4 nuclear units with net generating capacity totaling 3,479 MW (see Nuclear Operations below) and owned and operated 17 solar generation facilities with generating capacity totaling 1,157 MW (excluding 75 MW of non-incremental solar capability which is provided in conjunction with a natural gas generation facility). FPL customer usage and operating revenues are typically higher during the summer months, largely due to the prevalent use of air conditioning in FPL's service territory. Occasionally, unusually cold temperatures during the winter months result in significant increases in electricity usage for short periods of time.

FPL is in the process of modernizing two generating units at its Lauderdale facility to a high-efficiency, clean-burning natural gas unit (Dania Beach Clean Energy Center). The Dania Beach Clean Energy Center is expected to provide approximately 1,200 MW of generating capacity and to be in service in 2022.

Fuel Sources

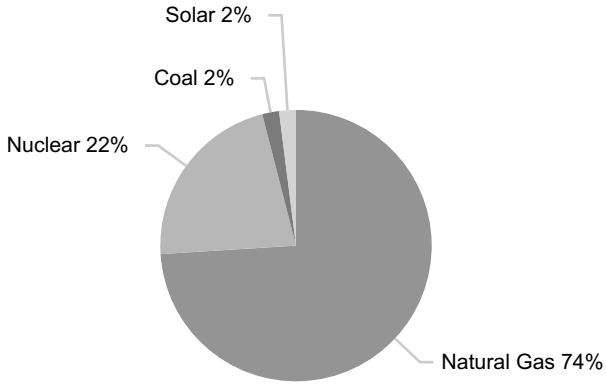
FPL relies upon a mix of fuel sources for its generation facilities, the ability of some of its generation facilities to operate on both natural gas and oil, and on purchased power to maintain the flexibility to achieve a more economical fuel mix in order to respond to market and industry developments.

**2019 Net Generating Capacity by Fuel Type**
**MW**




*approximately 71% has dual fuel capability

**2019 Net Generation by Fuel Type***
**MWh**




*Oil is less than 1%

*Significant Fuel and Transportation Contracts.* At December 31, 2019, FPL had the following significant fuel and transportation contracts in place:

- FPL has firm transportation contracts with seven different transportation suppliers for natural gas pipeline capacity for an aggregate maximum quantity of 2,769,000 MMBtu/day currently, of which 1,969,000 MMBtu/day have expiration dates ranging from 2020 to 2036. The remaining 800,000 MMBtu/day increases to 1,200,000 MMBtu/day starting in mid-2020 through 2042. See Note 15 - Contracts.
- FPL has several contracts for the supply of uranium and the conversion, enrichment and fabrication of nuclear fuel with expiration dates ranging from March 2020 through 2032.
- Additionally, FPL enters into short- and medium-term natural gas supply contracts to provide a portion of FPL's anticipated needs for natural gas. The remainder of FPL's natural gas requirements is purchased in the spot market.

Nuclear Operations

At December 31, 2019, FPL owned, or had undivided interests in, and operated the four nuclear units in Florida discussed below. FPL's nuclear units are periodically removed from service to accommodate planned refueling and maintenance outages, including inspections, repairs and certain other modifications. Scheduled nuclear refueling outages require the unit to be removed from service for variable lengths of time.

| Facility | FPL's Ownership (MW) | Beginning of Next Scheduled Refueling Outage | Operating License Expiration Date |
|---|---|---|---|
| St. Lucie Unit No. 1 | 981 | April 2021 | 2036 |
| St. Lucie Unit No. 2 | 840[(a)] | February 2020 | 2043 |
| Turkey Point Unit No. 3 | 837 | March 2020 | 2052 |
| Turkey Point Unit No. 4 | 821 | October 2020 | 2053 |

(a) Excludes 147 MW operated by FPL but owned by non-affiliates.

NRC regulations require FPL to submit a plan for decontamination and decommissioning five years before the projected end of plant operation. FPL's current plans, under the existing operating licenses, provide for St. Lucie Unit No. 1 to be shut down in 2036 with decommissioning activities to be integrated with the dismantlement of St. Lucie Unit No. 2 commencing in 2043. Current plans provide for the dismantlement of Turkey Point Units Nos. 3 and 4 with decommissioning activities commencing in 2052 and 2053, respectively.

Filed: 2020-11-04
FR-2020-0150
Exhibit A
Tab 5
Schedule 1
Attachment 3
Page 11 of 107

FPL's nuclear facilities use both on-site storage pools and dry storage casks to store spent nuclear fuel generated by these facilities, which are expected to provide sufficient storage of spent nuclear fuel that is generated at these facilities through license expiration.

## FPL ENERGY MARKETING AND TRADING

FPL's Energy Marketing & Trading division (EMT) buys and sells wholesale energy commodities, such as natural gas, oil and electricity. EMT procures natural gas and oil for FPL's use in power generation and sells excess natural gas, oil and electricity. EMT also uses derivative instruments (primarily swaps, options and forwards) to manage the physical and financial risks inherent in the purchase and sale of fuel and electricity. Substantially all of the results of EMT's activities are passed through to customers in the fuel or capacity clauses. See Management's Discussion - Energy Marketing and Trading and Market Risk Sensitivity and Note 4.

## FPL REGULATION

FPL's operations are subject to regulation by a number of federal, state and other organizations, including, but not limited to, the following:

- the FPSC, which has jurisdiction over retail rates, service territory, issuances of securities, planning, siting and construction of facilities, among other things;
- the FERC, which oversees the acquisition and disposition of generation, transmission and other facilities, transmission of electricity and natural gas in interstate commerce, proposals to build and operate interstate natural gas pipelines and storage facilities, and wholesale purchases and sales of electric energy, among other things;
- the NERC, which, through its regional entities, establishes and enforces mandatory reliability standards, subject to approval by the FERC, to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts;
- the NRC, which has jurisdiction over the operation of nuclear power plants through the issuance of operating licenses, rules, regulations and orders; and
- the EPA, which has the responsibility to maintain and enforce national standards under a variety of environmental laws, in some cases delegating authority to state agencies. The EPA also works with industries and all levels of government, including federal and state governments, in a wide variety of voluntary pollution prevention programs and energy conservation efforts.

### FPL Electric Rate Regulation

The FPSC sets rates at a level that is intended to allow FPL the opportunity to collect from retail customers total revenues (revenue requirements) equal to FPL's cost of providing service, including a reasonable rate of return on invested capital. To accomplish this, the FPSC uses various ratemaking mechanisms, including, among other things, base rates and cost recovery clauses.

*Base Rates.* In general, the basic costs of providing electric service, other than fuel and certain other costs, are recovered through base rates, which are designed to recover the costs of constructing, operating and maintaining the utility system. These basic costs include O&M expenses, depreciation and taxes, as well as a return on FPL's investment in assets used and useful in providing electric service (rate base). At the time base rates are established, the allowed rate of return on rate base approximates the FPSC's determination of FPL's estimated weighted-average cost of capital, which includes its costs for outstanding debt and an allowed return on common equity. The FPSC monitors FPL's actual regulatory ROE through a surveillance report that is filed monthly by FPL with the FPSC. The FPSC does not provide assurance that any regulatory ROE will be achieved. Base rates are determined in rate proceedings or through negotiated settlements of those proceedings. Proceedings can occur at the initiative of FPL or upon action by the FPSC. Existing base rates remain in effect until new base rates are approved by the FPSC.

*Base Rates Effective January 2017 through at least December 2020* - In December 2016, the FPSC issued a final order approving a stipulation and settlement between FPL and several intervenors in FPL's base rate proceeding (2016 rate agreement). Key elements of the 2016 rate agreement, which is effective from January 2017 through at least December 2020, include, among other things, the following:

- New retail base rates and charges were established resulting in the following increases in annualized retail base revenues:
    - $400 million beginning January 1, 2017;
    - $211 million beginning January 1, 2018; and
    - $200 million beginning April 1, 2019 for a new approximately 1,720 MW natural gas-fired combined-cycle unit in Okeechobee County, Florida (Okeechobee Clean Energy Center) that achieved commercial operation on March 31, 2019.
- In addition, FPL is eligible to receive base rate increases associated with the addition of up to 300 MW annually of new solar generation in each of 2017 through 2020 with an installed cost cap of $1,750 per kW. Approximately 900 MW of new solar generating capacity has become operational, 600 MW in the first quarter of 2018 and 300 MW in the first quarter of 2019. An additional 300 MW is expected to be operational in the second quarter of 2020.
- FPL's allowed regulatory ROE is 10.55%, with a range of 9.60% to 11.60%. If FPL's earned regulatory ROE falls below 9.60%, FPL may seek retail base rate relief. If the earned regulatory ROE rises above 11.60%, any party other than FPL may seek a review of FPL's retail base rates.

- Subject to certain conditions, FPL may amortize, over the term of the 2016 rate agreement, up to $1.0 billion of depreciation reserve surplus plus the reserve amount that remained under FPL's previous rate agreement (approximately $1.25 billion), provided that in any year of the 2016 rate agreement FPL must amortize at least enough reserve to maintain a 9.60% earned regulatory ROE but may not amortize any reserve that would result in an earned regulatory ROE in excess of 11.60%.
- Future storm restoration costs would be recoverable on an interim basis beginning 60 days from the filing of a cost recovery petition, but capped at an amount that could produce a surcharge of no more than $4 for every 1,000 kWh of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover amounts above $400 million. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery regarding several hurricanes that impacted FPL's service territory from 2016 - 2019.

*Cost Recovery Clauses*. Cost recovery clauses are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through various clauses. Cost recovery clause costs are recovered through levelized monthly charges per kWh or kW, depending on the customer's rate class. These cost recovery clause charges are calculated annually based on estimated costs and estimated customer usage for the following year, plus or minus true-up adjustments to reflect the estimated over or under recovery of costs for the current and prior periods. An adjustment to the levelized charges may be approved during the course of a year to reflect revised estimates. FPL recovers costs from customers through the following clauses:

- Fuel - primarily fuel costs, the most significant of the cost recovery clauses in terms of operating revenues (see Note 1 - Rate Regulation);
- Capacity - primarily certain costs associated with the acquisition of several electric generation facilities (see Note 1 - Rate Regulation);
- Energy Conservation - costs associated with implementing energy conservation programs; and
- Environmental - certain costs of complying with federal, state and local environmental regulations enacted after April 1993 and costs associated with three of FPL's solar facilities placed in service prior to 2016.

In June 2019, Florida's Governor signed legislation into law which directed the FPSC to propose new rules that would (i) require state investor-owned utilities to submit a 10-year transmission and distribution storm protection plan (SPP) to the FPSC for approval at least every three years and (ii) provide for annual clause recovery of storm protection plan costs not already recovered in base rates or through other clauses, including costs for hardening of overhead transmission and distribution lines, undergrounding of certain distribution lines and vegetation management. In October 2019, the FPSC issued its proposed SPP and SPP cost recovery clause rules. Final rules will become effective on February 18, 2020.

The FPSC has the authority to disallow recovery of costs that it considers excessive or imprudently incurred. These costs may include, among others, fuel and O&M expenses, the cost of replacing power lost when fossil and nuclear units are unavailable, storm restoration costs and costs associated with the construction or acquisition of new facilities.

## FERC

The Federal Power Act grants the FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity and natural gas in interstate commerce. Pursuant to the Federal Power Act, electric utilities must maintain tariffs and rate schedules on file with the FERC which govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. The Federal Power Act also gives the FERC authority to certify and oversee an electric reliability organization with authority to establish and independently enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. See NERC below. Electric utilities are subject to accounting, record-keeping and reporting requirements administered by the FERC. The FERC also places certain limitations on transactions between electric utilities and their affiliates.

## NERC

The NERC has been certified by the FERC as an electric reliability organization. The NERC's mandate is to ensure the reliability and security of the North American bulk-power system through the establishment and enforcement of reliability standards approved by FERC. The NERC's regional entities also enforce reliability standards approved by the FERC. FPL is subject to these reliability standards and incurs costs to ensure compliance with continually heightened requirements, and can incur significant penalties for failing to comply with them.

## FPL Environmental Regulation

FPL is subject to environmental laws and regulations as described in the NEE Environmental Matters section below. FPL expects to seek recovery through the environmental clause for compliance costs associated with any new environmental laws and regulations.

## FPL EMPLOYEES

FPL had approximately 8,900 employees at December 31, 2019, with approximately 32% of these employees represented by the International Brotherhood of Electrical Workers (IBEW), substantially all of which are under a collective bargaining agreement with FPL that expires October 31, 2020.

## NEER

NextEra Energy Resources was formed in 1998 to aggregate NEE's competitive energy businesses. During the fourth quarter of 2019, NEE began reporting NextEra Energy Resources and NEET, a rate-regulated transmission business, on a combined basis for segment reporting purposes, and the combined segment is referred to as NEER. NEET previously was reported in Corporate and Other. See Note 16. NEER is a diversified clean energy business with a strategy that emphasizes the development, construction and operation of long-term contracted assets with a focus on renewable projects. The NEER segment currently owns, develops, constructs, manages and operates electric generation facilities in wholesale energy markets primarily in the U.S. and Canada. NEER, with approximately 21,900 MW of total net generating capacity at December 31, 2019, is one of the largest wholesale generators of electric power in the U.S., including approximately 21,240 MW of net generating capacity across 37 states and 520 MW of net generating capacity in 4 Canadian provinces (see Note 1 - Disposal of Businesses/Assets). At December 31, 2019, NEER operates facilities with a total generating capacity of 24,700 MW. NEER produces the majority of its electricity from clean and renewable sources as described more fully below. NEER is the world's largest generator of renewable energy from the wind and sun based on 2019 MWh produced on a net generation basis. In addition, NEER develops and constructs battery storage projects, which when combined with its renewable projects, serve to enhance its ability to meet customer needs for a nearly firm generation source. NEER also owns and operates rate-regulated transmission facilities, primarily in Texas and California, and transmission lines that connect its electric generation facilities to the electric grid, which are comprised of approximately 190 substations and 1,865 circuit miles of transmission lines at December 31, 2019.

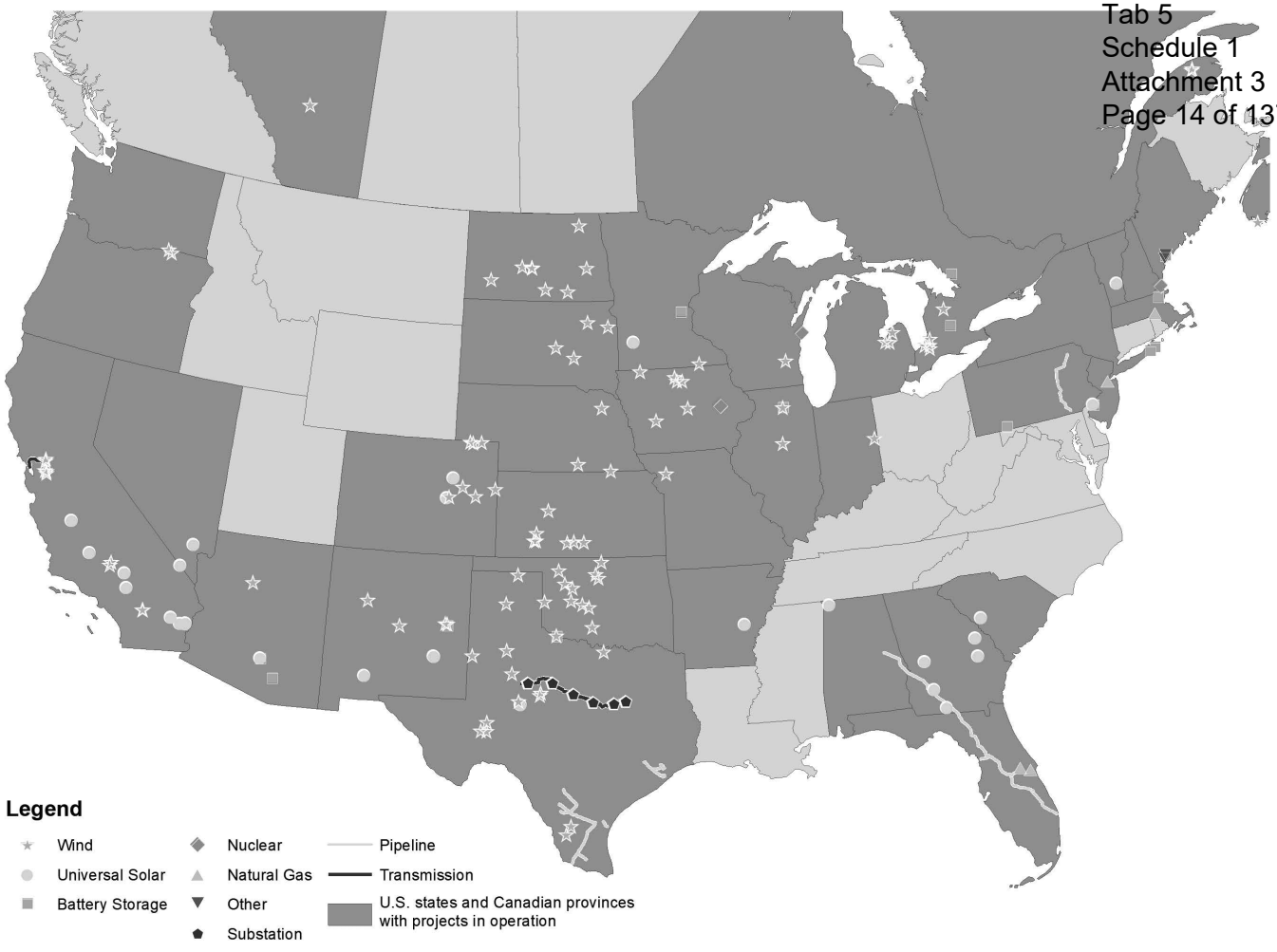
NEER also engages in energy-related commodity marketing and trading activities, including entering into financial and physical contracts, primarily to hedge the production from its generation assets that is not sold under long-term power supply agreements. These contracts primarily include power and gas commodities and their related products, as well as provide full energy and capacity requirements services primarily to distribution utilities in certain markets and offer customized power and gas and related risk management services to wholesale customers. In addition, NEER participates in natural gas, natural gas liquids and oil production through operating and non-operating ownership interests, and in pipeline infrastructure development, construction, management and operations, through either wholly owned subsidiaries or noncontrolling or joint venture interests, hereafter referred to as the gas infrastructure business. NEER also hedges the expected output from its gas infrastructure production assets to protect against price movements.

*NEP* - NEP was formed in 2014 to acquire, manage and own contracted clean energy projects with stable long-term cash flows through a limited partner interest in NEP OpCo. NEP's projects include energy projects contributed by NextEra Energy Resources to NEP OpCo in connection with NEP's initial public offering in July 2014 as well as additional energy projects acquired thereafter. NextEra Energy Resources' indirect limited partnership interest in NEP OpCo based on the number of outstanding NEP OpCo common units was approximately 60.8% at December 31, 2019. NEP was deconsolidated from NEE for financial reporting purposes in January 2018 as a result of changes made to NEP's governance structure that enhanced NEP unitholder governance rights. As a result, NextEra Energy Resources began reflecting its ownership interest in NEP as an equity method investment with its earnings/losses from NEP as equity in earnings (losses) of equity method investees and accounting for its asset sales to NEP as third-party sales in its consolidated financial statements. See Note 1 - NextEra Energy Partners, LP. Prior to the deconsolidation, NEE owned a controlling general partner interest in NEP and consolidated NEP. At December 31, 2019, NEP owned, or had an interest in, a portfolio of 36 wind and solar projects with generating capacity totaling approximately 5,331 MW and had membership interests in contracted natural gas pipelines, all located in the U.S. as further discussed in Generation and Other Operations. NextEra Energy Resources operates essentially all of the energy projects in NEP's portfolio and its ownership interest in the portfolio's generating capacity was approximately 3,240 MW at December 31, 2019.

## GENERATION AND OTHER OPERATIONS

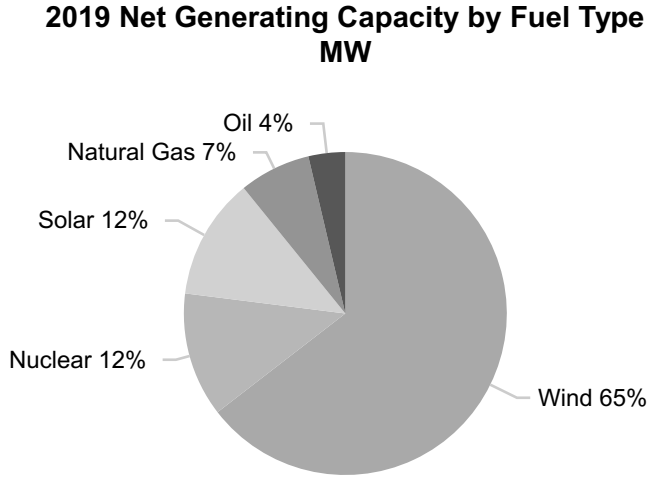
NEER sells products associated with its own generation facilities (energy, capacity, renewable energy credits (RECs) and ancillary services) in competitive markets in regions where those facilities are located. Customer transactions may be supplied from NEER generation facilities or from purchases in the wholesale markets, or from a combination thereof. See Markets and Competition below.

At December 31, 2019, NEER managed or participated in the management of essentially all of the following generation projects, natural gas pipelines and transmission facilities that it wholly owned or in which it had an ownership interest.




Locations with more than one facility are illustrated with a single symbol.
Map excludes small-scale solar.

## Generation Assets and Other Operations



*Generation Assets.*

NEER's portfolio of generation assets primarily consist of generation facilities with long-term power sales agreements for substantially all of their capacity and/or energy output. Information related to contracted generation assets at December 31, 2019 was as follows:

- represented approximately 19,796 MW of total net generating capacity;
- weighted-average remaining contract term of the power sales agreements and the remaining life of the PTCs associated with repowered wind facilities of approximately 16 years, based on forecasted contributions to earnings and forecasted amounts of electricity produced by the repowered wind facilities; and
- contracts for the supply of uranium and the conversion, enrichment and fabrication of nuclear fuel have expiration dates ranging from March 2020 through 2033 (see Note 15 - Contracts).

NEER's merchant generation assets primarily consist of a nuclear generation facility and oil-fired generation facilities that do not have long-term power sales agreements to sell their capacity and/or energy output and therefore require active marketing and hedging. Merchant generation assets at December 31, 2019 represented approximately 2,070 MW of total net generating capacity, including 1,102 MW from nuclear generation and 805 MW from oil-fired peak generation facilities, and are primarily located in the Northeast region of the U.S. NEER utilizes swaps, options, futures and forwards to lock in pricing and manage the commodity price risk inherent in power sales and fuel purchases.

*Other Operations.*

*Gas Infrastructure Business* - At December 31, 2019, NextEra Energy Resources had ownership interests in natural gas pipelines, the most significant of which are discussed below, and in oil and gas shale formations located primarily in the Midwest and South regions of the U.S.

| | Miles of Pipeline | Pipeline Location/Route | Ownership | | Total Net Capacity (per day) | Actual/Expected In-Service Dates |
|---|---|---|---|---|---|---|
| Operational: | | | | | | |
| Texas Pipelines[a] | 542 | South Texas | 58.8% | [b] | 2.32 Bcf | 1950 - 2014 |
| Sabal Trail[c] | 517 | Southwestern Alabama to Central Florida | 42.5% | | 0.35 Bcf - 0.46 Bcf | June 2017 - Mid-2021 |
| Florida Southeast Connection[c] | 169 | Central Florida to South Florida | 100% | | 0.64 Bcf | June 2017 |
| Central Penn Line[d] | 185 | Northeastern Pennsylvania to Southeastern Pennsylvania | 23.7% | [b] | 0.30 Bcf - 0.43 Bcf | October 2018 - Mid-2022 |
| Under Construction: | | | | | | |
| Mountain Valley Pipeline[e] | 303 | Northwestern West Virginia to Southern Virginia | 31% | | 0.62 Bcf | End of 2020 |

(a) A NEP portfolio of seven natural gas pipelines, of which a third party owns a 10% interest in a 120-mile pipeline with a daily capacity of approximately 2.3 Bcf. Approximately 1.82 Bcf per day of net capacity is contracted with firm ship-or-pay contracts that have expiration dates ranging from 2020 to 2035.
(b) Ownership percentage based on NextEra Energy Resources limited partnership interest in NEP OpCo common units.
(c) See Note 15 - Contracts for a discussion of transportation contracts with FPL.
(d) NEP has an indirect equity method investment in the Central Penn Line (CPL) which represents an approximately 39% aggregate ownership interest in the CPL.
(e) Completion of construction of the natural gas pipeline is subject to final permitting. Also, see Note 15 - Contracts for a discussion of a transportation contract with a NextEra Energy Resources subsidiary.

*Rate-Regulated Transmission* - At December 31, 2019, certain entities within the NEER segment had ownership interests in rate-regulated transmission facilities, the most significant of which are discussed below, which facilities are located primarily in ERCOT, CAISO and Independent Electricity System Operator (IESO) jurisdictions.

| | Miles | Substations | Kilovolt | Location | Rate Regulator | Ownership | Actual/Expected In-Service Dates |
|---|---|---|---|---|---|---|---|
| Operational: | | | | | | | |
| Lone Star | 330 | 6 | 345 | Central Texas | PUCT | 100% | 2013 |
| Trans Bay Cable | 53 | 2 | 200 DC[a] | Northern California | FERC | 100% | 2010 |
| Under Construction: | | | | | | | |
| NextBridge Infrastructure | 280 | - | 230 | Ontario, Canada | OEB | 50% | Fourth Quarter of 2021 |

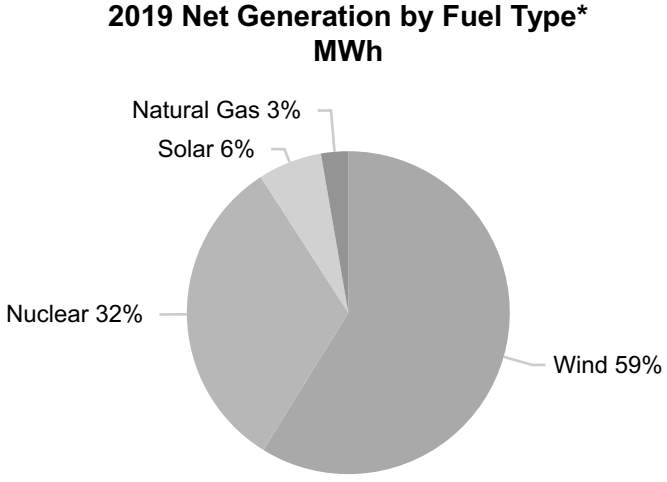
(a) Direct current

*Customer Supply and Proprietary Power and Gas Trading* - NEER provides commodities-related products to customers, engages in energy-related commodity marketing and trading activities and includes the operations of a retail electricity provider. Through NextEra Energy Resources subsidiary PMI, NEER:

- manages risk associated with fluctuating commodity prices and optimizes the value of NEER's power generation and gas infrastructure production assets through the use of swaps, options, futures and forwards;
- sells output from NEER's plants that is not sold under long-term contracts and procures fossil fuel for use by NEER's generation fleet;
- provides full energy and capacity requirements to customers; and
- markets and trades energy-related commodity products and provides a wide range of electricity and fuel commodity products as well as marketing and trading services to customers.

NEER Generation Assets Fuel/Technology Mix

NextEra Energy Resources utilized the following mix of fuel sources for generation facilities in which it has an ownership interest:




*Oil is less than 1%

*Wind Facilities*

- located in 19 states in the U.S. and 4 provinces in Canada;
- operated a total generating capacity of 15,955 MW at December 31, 2019;
- ownership interests in a total net generating capacity of 14,111 MW at December 31, 2019;
    - all MW are from contracted wind assets located primarily throughout Texas and the West and Midwest regions of the U.S. and Canada;
    - added approximately 1,125 MW of new generating capacity and repowered wind generating capacity totaling 1,091 MW in the U.S. in 2019 (see Note 1 - Disposal of Businesses/Assets for asset sales to NEP).

*Solar Facilities*

- located in 26 states in the U.S.;
- operated PV and solar thermal facilities with a total generating capacity of 2,684 MW at December 31, 2019;
- ownership interests in PV and solar thermal facilities with a total net generating capacity of 2,662 MW at December 31, 2019;
    - essentially all MW are from contracted solar facilities located primarily throughout the West and South regions of the U.S.;
    - added approximately 512 MW of generating capacity in the U.S. in 2019 (see Note 1 - Disposal of Businesses/Assets for asset sales to NEP).

*Fossil Facilities*

- operated natural gas generation facilities with a total generating capacity of 2,110 MW at December 31, 2019;
- ownership interests in natural gas generation facilities with a total net generating capacity of 1,565 MW at December 31, 2019;
  - approximately 1,407 MW are contracted and 158 MW are merchant;
  - located in 2 states in the Northeast region of the U.S. and in Florida; and
- operated oil-fired peak generation facilities with a total generating capacity of 878 MW with an ownership or undivided interests in total net generating capacity of 805 MW at December 31, 2019 primarily located in Maine.

*Nuclear Facilities*

At December 31, 2019, NextEra Energy Resources owned, or had undivided interests in, and operated the four nuclear units discussed below. NEER's nuclear units are periodically removed from service to accommodate planned refueling and maintenance outages, including inspections, repairs and certain other modifications. Scheduled nuclear refueling outages require the unit to be removed from service for variable lengths of time.

| Facility | Location | Ownership (MW) | Portfolio Category | Next Scheduled Refueling Outage | Operating License Expiration Date |
|---|---|---|---|---|---|
| Seabrook | New Hampshire | 1,102[(a)] | Merchant | April 2020 | 2050 |
| Duane Arnold | Iowa | 431[(b)] | Contracted[(c)] | None[(c)] | 2034[(c)] |
| Point Beach Unit No. 1 | Wisconsin | 595 | Contracted[(d)] | October 2020 | 2030 |
| Point Beach Unit No. 2 | Wisconsin | 595 | Contracted[(d)] | March 2020 | 2033 |

(a) Excludes 147 MW operated by NEER but owned by non-affiliates.
(b) Excludes 184 MW operated by NEER but owned by non-affiliates.
(c) NEER sells all of its share of the output of Duane Arnold under an amended long-term contract expiring in December 2020. Operations of Duane Arnold are expected to cease in late 2020. See Note 5 - Nonrecurring Fair Value Measurements.
(d) NEER sells all of the output of Point Beach Units Nos. 1 and 2 under long-term contracts through their current operating license expiration dates.

NEER is responsible for all nuclear unit operations and the ultimate decommissioning of the nuclear units, the cost of which is shared on a pro-rata basis by the joint owners for the jointly-owned units. NRC regulations require plant owners to submit a plan for decontamination and decommissioning five years before the projected end of plant operation. In the case of Duane Arnold, a plan for decontamination and decommissioning is required to be submitted to the NRC no later than 2 years following shutdown of the facility.

NEER's nuclear facilities use both on-site storage pools and dry storage casks to store spent nuclear fuel generated by these facilities, which are expected to provide sufficient storage of spent nuclear fuel that is generated at these facilities through license expiration or, in the case of Duane Arnold, through expected shutdown of the facility.

*Policy Incentives for Renewable Energy Projects*

U.S. federal, state and local governments have established various incentives to support the development of renewable energy projects. These incentives include accelerated tax depreciation, PTCs, ITCs, cash grants, tax abatements and RPS programs. Pursuant to the U.S. federal Modified Accelerated Cost Recovery System, wind and solar projects are fully depreciated for tax purposes over a five-year period even though the useful life of such projects is generally much longer than five years.

Owners of utility-scale wind facilities are eligible to claim an income tax credit (the PTC, or an ITC in lieu of the PTC) upon initially achieving commercial operation. The PTC is determined based on the amount of electricity produced by the wind facility during the first ten years of commercial operation. This incentive was created under the Energy Policy Act of 1992 and has been extended several times. Alternatively, an ITC equal to 30% of the cost of a wind facility may be claimed in lieu of the PTC. Owners of solar facilities are eligible to claim a 30% ITC for new solar facilities. Previously, owners of solar facilities could have elected to receive an equivalent cash payment from the U.S. Department of Treasury for the value of the 30% ITC (convertible ITC) for qualifying solar facilities where construction began before the end of 2011 and the facilities were placed in service before 2017. In order to qualify for the PTC (or an ITC in lieu of the PTC) for wind or ITC for solar, construction of a facility must begin before a specified date and the taxpayer must maintain a continuous program of construction or continuous efforts to advance the project to completion. The Internal Revenue Service (IRS) issued guidance stating that the safe harbor for continuous efforts and continuous construction requirements will generally be satisfied if the facility is placed in service no more than four years after the year in which construction of the facility began. The IRS also confirmed that retrofitted wind facilities may re-qualify for PTCs or ITCs pursuant to the 5% safe harbor for the begin construction requirement, as long as the cost basis of the new investment is at least 80% of the facility's total fair value. Tax credits for qualifying wind and solar projects are subject to the following schedule.

| | Year construction of project begins[a] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| PTC[b] | 100% | 100% | 80% | 60% | 40% | 60% | - | - |
| Wind ITC[c] | 30% | 30% | 24% | 18% | 12% | 18% | - | - |
| Solar ITC[d] | 30% | 30% | 30% | 30% | 30% | 26% | 10% | 10% |

(a) Project must be placed in service no more than four years after the year in which construction of the project began to qualify for the PTC or ITC.
(b) Percentage of the full PTC available for wind projects that begin construction during the applicable year.
(c) Percentage of eligible project costs that can be claimed as ITC by wind projects that begin construction during the applicable year.
(d) Percentage of eligible project costs that can be claimed as ITC by solar projects that begin construction during the applicable year. ITC is limited to 10% for solar projects not placed in service before January 1, 2024.

Other countries, including Canada, provide for incentives like feed-in-tariffs for renewable energy projects. The feed-in-tariffs promote renewable energy investments by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology.

## MARKETS AND COMPETITION

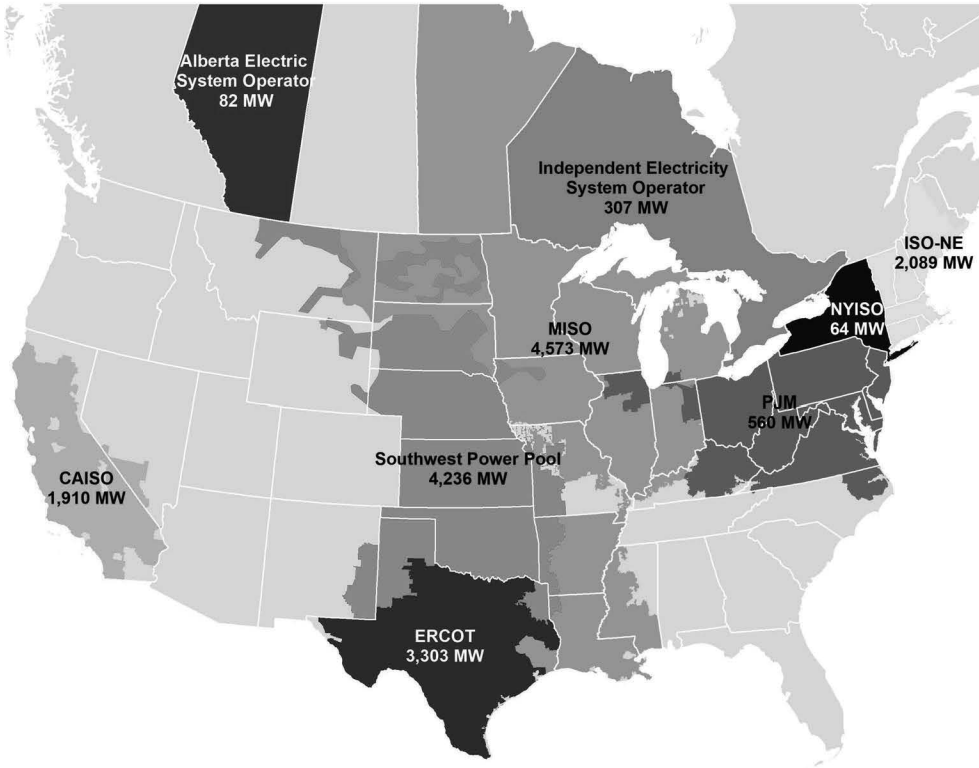
Electricity markets in the U.S. and Canada are regional and diverse in character. All are extensively regulated, and competition in these markets is shaped and constrained by regulation. The nature of the products offered varies based on the specifics of regulation in each region. Generally, in addition to the natural constraints on pricing freedom presented by competition, NEER may also face specific constraints in the form of price caps, or maximum allowed prices, for certain products. NEER's ability to sell the output of its generation facilities may also be constrained by available transmission capacity, which can vary from time to time and can have a significant impact on pricing.

The degree and nature of competition is different in wholesale markets than in retail markets. During 2019, 2018 and 2017, approximately 85% of NEER's revenue was derived from wholesale electricity markets.

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NEER primarily competes on the basis of price, but believes the green attributes of NEER's generation assets, its creditworthiness and its ability to offer and manage reliable customized risk solutions to wholesale customers are competitive advantages. Wholesale power generation is a regional business that is highly fragmented relative to many other commodity industries and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies NEER competes with depending on the market. In wholesale markets, customers' needs are met through a variety of means, including long-term bilateral contracts, standardized bilateral products such as full requirements service and customized supply and risk management services.

In general, U.S. and Canadian electricity markets encompass three classes of services: energy, capacity and ancillary services. Energy services relate to the physical delivery of power; capacity services relate to the availability of MW capacity of a power generation asset; and ancillary services are other services that relate to power generation assets, such as load regulation and spinning and non-spinning reserves. The exact nature of these classes of services is defined in part by regional tariffs. Not all regions have a capacity services class, and the specific definitions of ancillary services vary from region to region.

RTOs and ISOs exist throughout much of North America to coordinate generation and transmission across wide geographic areas and to run markets. NEER operates in all RTO and ISO jurisdictions. At December 31, 2019, NEER also had generation facilities with ownership interests in a total net generating capacity of approximately 4,642 MW that fall within reliability regions that are not under the jurisdiction of an established RTO or ISO, including 2,365 MW within the Western Electricity Coordinating Council and 1,252 MW within the Florida Reliability Coordinating Council. Although each RTO and ISO may have differing objectives and structures, some benefits of these entities include regional planning, managing transmission congestion, developing larger wholesale markets for energy and capacity, maintaining reliability and facilitating competition among wholesale electricity providers. NEER has operations that fall within the following RTOs and ISOs:




NEER competes in different regions to differing degrees, but in general it seeks to enter into long-term bilateral contracts for the full output of its generation facilities. At December 31, 2019, approximately 90% of NEER's net generating capacity was committed under long-term contracts. Where long-term contracts are not in effect, NEER sells the output of its facilities into daily spot markets. In such cases, NEER will frequently enter into shorter term bilateral contracts, typically of less than three years duration, to hedge the price risk associated with selling into a daily spot market. Such bilateral contracts, which may be hedges either for physical delivery or for financial (pricing) offset, serve to protect a portion of the revenue that NEER expects to derive from the associated generation facility. Contracts that serve the economic purpose of hedging some portion of the expected revenue of a generation facility but are not recorded as hedges under GAAP are referred to as “non-qualifying hedges” for adjusted earnings purposes. See Management's Discussion - Overview - Adjusted Earnings.

Certain facilities within the NEER wind and solar generation portfolio produce RECs and other environmental attributes which are typically sold along with the energy from the plants under long-term contracts, or may be sold separately for the wind and solar generation not sold under long-term contracts. The purchasing party is solely entitled to the reporting rights and ownership of the environmental attributes.

While the majority of NEER's revenue is derived from the output of its generation facilities, NEER is also an active competitor in several regions in the wholesale full requirements business and in providing structured and customized power and fuel products and services to a variety of customers. In the full requirements service, typically, the supplier agrees to meet the customer's needs for a full range of products for every hour of the day, at a fixed price, for a predetermined period of time, thereby assuming the risk of fluctuations in the customer's volume requirements.

Expanded competition in a frequently changing regulatory environment presents both opportunities and risks for NEER. Opportunities exist for the selective acquisition of generation assets and for the construction and operation of efficient facilities that can sell power in competitive markets. NEER seeks to reduce its market risk by having a diversified portfolio by fuel type and location, as well as by contracting for the future sale of a significant amount of the electricity output of its facilities.

## NEER REGULATION

The energy markets in which NEER operates are subject to domestic and foreign regulation, as the case may be, including local, state and federal regulation, and other specific rules.

At December 31, 2019, essentially all of NEER's operating independent power projects located in the U.S. have received exempt wholesale generator status as defined under the Public Utility Holding Company Act of 2005. Exempt wholesale generators own

or operate a facility exclusively to sell electricity to wholesale customers. They are barred from selling electricity directly to retail customers. While projects with exempt wholesale generator status are exempt from various restrictions, each project must still comply with other federal, state and local laws, including, but not limited to, those regarding siting, construction, operation, licensing, pollution abatement and other environmental laws.

Additionally, most of the NEER facilities located in the U.S. are subject to FERC regulations and market rules and the NERC's mandatory reliability standards, all of its facilities are subject to environmental laws and the EPA's environmental regulations and its nuclear facilities are also subject to the jurisdiction of the NRC. See FPL - FPL Regulation for additional discussion of FERC, NERC, NRC and EPA regulations. Rates of NEER's rate-regulated transmission businesses are set by regulatory bodies as noted in Generation and Other Operations - Generation Assets and Other Operations - Other Operations - Rate-Regulated Transmission. With the exception of facilities located in ERCOT, the FERC has jurisdiction over various aspects of NEER's business in the U.S., including the oversight and investigation of competitive wholesale energy markets, regulation of the transmission and sale of natural gas, and oversight of environmental matters related to natural gas projects and major electricity policy initiatives. The PUCT has jurisdiction, including the regulation of rates and services, oversight of competitive markets, and enforcement of statutes and rules, over NEER facilities located in ERCOT.

Certain entities within the NEER segment and their affiliates are also subject to federal and provincial or regional regulations in Canada related to energy operations, energy markets and environmental standards. In Canada, activities related to owning and operating wind and solar projects and participating in wholesale and retail energy markets are regulated at the provincial level. In Ontario, for example, electricity generation facilities must be licensed by the OEB and may also be required to complete registrations and maintain market participant status with the IESO, in which case they must agree to be bound by and comply with the provisions of the market rules for the Ontario electricity market as well as the mandatory reliability standards of the NERC.

In addition, NEER is subject to environmental laws and regulations as described in the NEE Environmental Matters section below. In order to better anticipate potential regulatory changes, NEER continues to actively evaluate and participate in regional market redesigns of existing operating rules for the integration of renewable energy resources and for the purchase and sale of energy commodities.

### NEER EMPLOYEES

NEER had approximately 5,000 employees at December 31, 2019. NEER has collective bargaining agreements with the IBEW, the Utility Workers Union of America, and the Security Police and Fire Professionals of America, which collectively represent approximately 15% of NEER's employees. The collective bargaining agreements have two- to five-year terms and expire between March 2021 and September 2022.

## GULF POWER

On January 1, 2019, NEE completed the acquisition of all of the outstanding common shares of Gulf Power under a stock purchase agreement with The Southern Company dated May 20, 2018, as amended, for approximately $4.44 billion in cash consideration and the assumption of approximately $1.3 billion of Gulf Power debt. Gulf Power was incorporated under the laws of Maine in 1925 and became a Florida corporation after being domesticated under the laws of Florida in 2005. Gulf Power, a rate-regulated electric utility under the jurisdiction of the FPSC, is engaged in the generation, transmission, distribution and sale of electric energy in northwest Florida. Gulf Power is subject to regulations similar to FPL (see FPL - FPL Regulation above). Gulf Power operates under a base rate settlement agreement, which took effect July 1, 2017, that provides for an allowed regulatory ROE of 10.25%, with a range of 9.25% to 11.25%. As of December 31, 2019, Gulf Power served approximately 470,000 customers in eight counties throughout northwest Florida and had approximately 2,300 MW of fossil-fueled electric net generating capacity and 9,500 miles of transmission and distribution lines located primarily in Florida. See Note 8 - Gulf Power Company for further discussion.

## NEE ENVIRONMENTAL MATTERS

NEE and its subsidiaries, including FPL, are subject to environmental laws and regulations, including extensive federal, state and local environmental statutes, rules and regulations, for the siting, construction and ongoing operations of their facilities. The U.S. government and certain states and regions, as well as the Government of Canada and its provinces, have taken and continue to take certain actions, such as proposing and finalizing regulations or setting targets or goals, regarding the regulation and reduction of GHG emissions and the increase of renewable energy generation. Numerous environmental regulations also affecting FPL, NEER, Gulf Power, and certain other subsidiaries relate to threatened and endangered species and/or their habitats, as well as other avian and bat species. The environmental laws in the U.S., including, among others, the Endangered Species Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act, provide for the protection of numerous species, including endangered species of birds and bats and/or their habitats, migratory birds and eagles. The environmental laws in Canada, including, among others, the Species at Risk Act, provide for the recovery of wildlife species that are endangered or threatened and the management of species of special concern. Complying with these environmental laws and regulations could result in, among other things, changes in the design and operation of existing facilities and changes or delays in the location, design, construction and operation of new facilities. Failure to comply could result in fines, penalties, criminal sanctions or injunctions. The impact of complying with current environmental laws and regulations has not had, and, along with compliance with proposed regulations as currently written, is not expected to have, a material adverse effect on the financial statements of NEE and FPL. NEE's rate-regulated subsidiaries expect to seek recovery for compliance costs associated with any new environmental laws and regulations, which recovery for FPL and Gulf Power would be through their respective environmental clause.

## WEBSITE ACCESS TO SEC FILINGS

NEE and FPL make their SEC filings, including the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on NEE's internet website, www.nexteraenergy.com, as soon as reasonably practicable after those documents are electronically filed with or furnished to the SEC. The information and materials available on NEE's website (or any of its subsidiaries' or affiliates' websites) are not incorporated by reference into this combined Form 10-K.

Filed: 2020-11-04
EB-2020-0150
Exhibit A
Tab 3
Schedule 1
Attachment 3
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## INFORMATION ABOUT OUR EXECUTIVE OFFICERS[(a)]

| Name | Age | Position | Effective Date |
|---|---|---|---|
| Miguel Arechabala | 58 | Executive Vice President, Power Generation Division of NEE<br>Executive Vice President, Power Generation Division of FPL | January 1, 2014 |
| Deborah H. Caplan | 57 | Executive Vice President, Human Resources and Corporate Services of NEE<br>Executive Vice President, Human Resources and Corporate Services of FPL | April 15, 2019 |
| Paul I. Cutler | 60 | Treasurer of NEE<br>Treasurer of FPL<br>Assistant Secretary of NEE | February 19, 2003<br>February 18, 2003<br>December 10, 1997 |
| Joseph T. Kelliher | 59 | Executive Vice President, Federal Regulatory Affairs of NEE | May 18, 2009 |
| John W. Ketchum | 49 | President and Chief Executive Officer of NextEra Energy Resources | March 1, 2019 |
| Rebecca J. Kujawa | 44 | Executive Vice President, Finance and Chief Financial Officer of NEE<br>Executive Vice President, Finance and Chief Financial Officer of FPL | March 1, 2019 |
| James M. May | 43 | Vice President, Controller and Chief Accounting Officer of NEE | March 1, 2019 |
| Donald A. Moul | 54 | Executive Vice President, Nuclear Division and Chief Nuclear Officer of NEE<br>Vice President and Chief Nuclear Officer of FPL | January 1, 2020<br>May 17, 2019 |
| Ronald R. Reagan | 51 | Executive Vice President, Engineering, Construction and Integrated Supply Chain of NEE<br>Vice President, Engineering and Construction of FPL | January 1, 2020<br>March 1, 2019 |
| James L. Robo | 57 | Chairman, President and Chief Executive Officer of NEE<br>Chairman of FPL | December 13, 2013<br>May 2, 2012 |
| Charles E. Sieving | 47 | Executive Vice President & General Counsel of NEE<br>Executive Vice President of FPL | December 1, 2008<br>January 1, 2009 |
| Eric E. Silagy | 54 | President and Chief Executive Officer of FPL | May 30, 2014 |

(a) Information is as of February 14, 2020. Executive officers are elected annually by, and serve at the pleasure of, their respective boards of directors. Except as noted below, each officer has held his/her present position for five years or more and his/her employment history is continuous. Mr. Ketchum served as Executive Vice President, Finance and Chief Financial Officer of NEE and FPL from March 2016 to February 2019 and NEE's Senior Vice President, Finance from February 2015 to March 2016. Ms. Kujawa served as Vice President, Business Management of NextEra Energy Resources from March 2012 to February 2019. Mr. May served as Controller of NextEra Energy Resources from April 2015 to February 2019 and was Director of Accounting of NextEra Energy Resources from July 2013 to April 2015. Mr. Moul served as Vice President and Chief Nuclear Officer of NEE from May 2019 to December 2019. He previously held various roles at several subsidiaries of FirstEnergy Corp., which are energy suppliers involved in the generation, transmission and distribution of electricity. Mr. Moul was Executive on Special Assignment of FirstEnergy Solutions Corp. from March 2019 to May 2019, President and Chief Nuclear Officer of FirstEnergy Generation Companies from March 2018 to March 2019, President of FirstEnergy Generation LLC from April 2017 to March 2018, Senior Vice President, Fossil Operations and Environmental of FirstEnergy Solutions from August 2015 to April 2017, and Vice President, Commodity Operations of FirstEnergy Solutions from October 2012 to August 2015. Mr. Reagan served as Vice President, Engineering and Construction of NEE from November 2018 to December 2019 and Vice President, Integrated Supply Chain of NEE from October 2012 to November 2018.

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## Risks Relating to NEE's and FPL's Business

The business, financial condition, results of operations and prospects of NEE and FPL are subject to a variety of risks, many of which are beyond the control of NEE and FPL. These risks, as well as additional risks and uncertainties either not presently known or that are currently believed to not be material to the business, may materially adversely affect the business, financial condition, results of operations and prospects of NEE and FPL and may cause actual results of NEE and FPL to differ substantially from those that NEE or FPL currently expects or seeks. In that event, the market price for the securities of NEE or FPL could decline. Accordingly, the risks described below should be carefully considered together with the other information set forth in this report and in future reports that NEE and FPL file with the SEC.

### Regulatory, Legislative and Legal Risks

**NEE's and FPL's business, financial condition, results of operations and prospects may be materially adversely affected by the extensive regulation of their business.**

The operations of NEE and FPL are subject to complex and comprehensive federal, state and other regulation. This extensive regulatory framework, portions of which are more specifically identified in the following risk factors, regulates, among other things and to varying degrees, NEE's and FPL's industry, businesses, rates and cost structures, operation and licensing of nuclear power facilities, construction and operation of electricity generation, transmission and distribution facilities and natural gas and oil production, natural gas, oil and other fuel transportation, processing and storage facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, decommissioning costs and funding, service reliability, wholesale and retail competition, and commodities trading and derivatives transactions. In their business planning and in the management of their operations, NEE and FPL must address the effects of regulation on their business and any inability or failure to do so adequately could have a material adverse effect on their business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if they are unable to recover in a timely manner any significant amount of costs, a return on certain assets or a reasonable return on invested capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise.**

FPL operates as an electric utility and is subject to the jurisdiction of the FPSC over a wide range of business activities, including, among other items, the retail rates charged to its customers through base rates and cost recovery clauses, the terms and conditions of its services, procurement of electricity for its customers and fuel for its plant operations, issuances of securities, and aspects of the siting, construction and operation of its generation plants and transmission and distribution systems for the sale of electric energy. The FPSC has the authority to disallow recovery by FPL of costs that it considers excessive or imprudently incurred and to determine the level of return that FPL is permitted to earn on invested capital. The regulatory process, which may be adversely affected by the political, regulatory and economic environment in Florida and elsewhere, limits or could otherwise adversely impact FPL's earnings. The regulatory process also does not provide any assurance as to achievement of authorized or other earnings levels, or that FPL will be permitted to earn an acceptable return on capital investments it wishes to make. NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if any material amount of costs, a return on certain assets or a reasonable return on invested capital cannot be recovered through base rates, cost recovery clauses, other regulatory mechanisms or otherwise. Certain other subsidiaries of NEE are utilities subject to the jurisdiction of their regulators and are subject to similar risks.

**Regulatory decisions that are important to NEE and FPL may be materially adversely affected by political, regulatory and economic factors.**

The local and national political, regulatory and economic environment has had, and may in the future have, an adverse effect on FPSC decisions with negative consequences for FPL. These decisions may require, for example, FPL to cancel or delay planned development activities, to reduce or delay other planned capital expenditures or to pay for investments or otherwise incur costs that it may not be able to recover through rates, each of which could have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL. Certain other subsidiaries of NEE are subject to similar risks.

**FPL's use of derivative instruments could be subject to prudence challenges and, if found imprudent, could result in disallowances of cost recovery for such use by the FPSC.**

The FPSC engages in an annual prudence review of FPL's use of derivative instruments in its risk management fuel procurement program and should it find any such use to be imprudent, the FPSC could deny cost recovery for such use by FPL. Such an outcome could have a material adverse effect on FPL's business, financial condition, results of operations and prospects.

**Any reductions or modifications to, or the elimination of, governmental incentives or policies that support utility scale renewable energy, including, but not limited to, tax laws, policies and incentives, RPS or feed-in tariffs, or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for the development and/or financing of new renewable energy projects, NEER abandoning the development of**

**renewable energy projects, a loss of NEER's investments in renewable energy projects and reduced project returns, any of which could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.**

NEER depends heavily on government policies that support utility scale renewable energy and enhance the economic feasibility of developing and operating wind and solar energy projects in regions in which NEER operates or plans to develop and operate renewable energy facilities. The federal government, a majority of state governments in the U.S. and portions of Canada provide incentives, such as tax incentives, RPS or feed-in tariffs, that support or are designed to support the sale of energy from utility scale renewable energy facilities, such as wind and solar energy facilities. As a result of budgetary constraints, political factors or otherwise, governments from time to time may review their laws and policies that support renewable energy and consider actions that would make the laws and policies less conducive to the development and operation of renewable energy facilities. Any reductions or modifications to, or the elimination of, governmental incentives or policies that support renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for the development and/or financing of new renewable energy projects, NEER abandoning the development of renewable energy projects, a loss of NEER's investments in the projects and reduced project returns, any of which could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected as a result of new or revised laws, regulations, interpretations or ballot or regulatory initiatives.**

NEE's and FPL's business is influenced by various legislative and regulatory initiatives, including, but not limited to, new or revised laws, including international trade laws, regulations, interpretations or ballot or regulatory initiatives regarding deregulation or restructuring of the energy industry, regulation of the commodities trading and derivatives markets, and regulation of environmental matters, such as regulation of air emissions, regulation of water consumption and water discharges, and regulation of gas and oil infrastructure operations, as well as associated environmental permitting. Changes in the nature of the regulation of NEE's and FPL's business could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects. NEE and FPL are unable to predict future legislative or regulatory changes, initiatives or interpretations, although any such changes, initiatives or interpretations may increase costs and competitive pressures on NEE and FPL, which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

FPL has limited competition in the Florida market for retail electricity customers. Any changes in Florida law or regulation which introduce competition in the Florida retail electricity market, such as government incentives that facilitate the installation of solar generation facilities on residential or other rooftops at below cost or that are otherwise subsidized by non-participants, or would permit third-party sales of electricity, could have a material adverse effect on FPL's business, financial condition, results of operations and prospects. There can be no assurance that FPL will be able to respond adequately to such regulatory changes, which could have a material adverse effect on FPL's business, financial condition, results of operations and prospects.

NEER is subject to FERC rules related to transmission that are designed to facilitate competition in the wholesale market on practically a nationwide basis by providing greater certainty, flexibility and more choices to wholesale power customers. NEE cannot predict the impact of changing FERC rules or the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond NEE's control. There can be no assurance that NEER will be able to respond adequately or sufficiently quickly to such rules and developments, or to any changes that reverse or restrict the competitive restructuring of the energy industry in those jurisdictions in which such restructuring has occurred. Any of these events could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

NEE’s and FPL’s OTC financial derivatives are subject to rules implementing certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and similar international regulations. NEE and FPL cannot predict the impact any proposed or not fully implemented final rules will have on their ability to hedge their commodity and interest rate risks or on OTC derivatives markets as a whole, but such rules and regulations could have a material adverse effect on NEE's and FPL's risk exposure, as well as reduce market liquidity and further increase the cost of hedging activities.

**NEE and FPL are subject to numerous environmental laws, regulations and other standards that may result in capital expenditures, increased operating costs and various liabilities, and may require NEE and FPL to limit or eliminate certain operations.**

NEE and FPL are subject to domestic environmental laws, regulations and other standards, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, climate change, emissions of greenhouse gases, including, but not limited to, carbon dioxide, waste management, hazardous wastes, marine, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health (including, but not limited to, electric and magnetic fields from power lines and substations), safety and RPS, that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict or enjoin the output of some existing facilities, limit the availability and use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations. Certain subsidiaries of NEE are also subject to foreign environmental laws, regulations and other standards and, as such, are subject to similar risks.

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There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new requirements and/or more expansive application of existing environmental laws and regulations.

Violations of current or future laws, rules, regulations or other standards could expose NEE and FPL to regulatory and legal proceedings, disputes with, and legal challenges by, governmental entities and third parties, and potentially significant civil fines, criminal penalties and other sanctions. Proceedings could include, for example, litigation regarding property damage, personal injury, common law nuisance and enforcement by citizens or governmental authorities of environmental requirements.

**NEE's and FPL's business could be negatively affected by federal or state laws or regulations mandating new or additional limits on the production of greenhouse gas emissions.**

Federal or state laws or regulations may be adopted that would impose new or additional limits on the emissions of greenhouse gases, including, but not limited to, carbon dioxide and methane, from electric generation units using fossil fuels like coal and natural gas. The potential effects of greenhouse gas emission limits on NEE's and FPL's electric generation units are subject to significant uncertainties based on, among other things, the timing of the implementation of any new requirements, the required levels of emission reductions, the nature of any market-based or tax-based mechanisms adopted to facilitate reductions, the relative availability of greenhouse gas emission reduction offsets, the development of cost-effective, commercial-scale carbon capture and storage technology and supporting regulations and liability mitigation measures, and the range of available compliance alternatives.

While NEE's and FPL's electric generation units emit greenhouse gases at a lower rate of emissions than most of the U.S. electric generation sector, the results of operations of NEE and FPL could be materially adversely affected to the extent that new federal or state laws or regulations impose any new greenhouse gas emission limits. Any future limits on greenhouse gas emissions could:

- create substantial additional costs in the form of taxes or emission allowances;
- make some of NEE's and FPL's electric generation units uneconomical to operate in the long term;
- require significant capital investment in carbon capture and storage technology, fuel switching, or the replacement of high-emitting generation facilities with lower-emitting generation facilities; or
- affect the availability or cost of fossil fuels.

There can be no assurance that NEE or FPL would be able to completely recover any such costs or investments, which could have a material adverse effect on their business, financial condition, results of operations and prospects.

**Extensive federal regulation of the operations and businesses of NEE and FPL exposes NEE and FPL to significant and increasing compliance costs and may also expose them to substantial monetary penalties and other sanctions for compliance failures.**

NEE's and FPL's operations and businesses are subject to extensive federal regulation, which generally imposes significant and increasing compliance costs on their operations and businesses. Additionally, any actual or alleged compliance failures could result in significant costs and other potentially adverse effects of regulatory investigations, proceedings, settlements, decisions and claims, including, among other items, potentially significant monetary penalties. As an example, under the Energy Policy Act of 2005, NEE and FPL, as owners and operators of bulk-power transmission systems and/or electric generation facilities, are subject to mandatory reliability standards. Compliance with these mandatory reliability standards may subject NEE and FPL to higher operating costs and may result in increased capital expenditures. If FPL or NEE is found not to be in compliance with these standards, they may incur substantial monetary penalties and other sanctions. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**Changes in tax laws, guidance or policies, including but not limited to changes in corporate income tax rates, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.**

NEE's and FPL's provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, guidance or policies, including changes in corporate income tax rates, the financial condition and results of operations of NEE and FPL, and the resolution of audit issues raised by taxing authorities. These factors, including the ultimate resolution of income tax matters, may result in material adjustments to tax-related assets and liabilities, which could materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects may be materially adversely affected due to adverse results of litigation.**

NEE's and FPL's business, financial condition, results of operations and prospects may be materially affected by adverse results of litigation. Unfavorable resolution of legal proceedings in which NEE or FPL is involved or other future legal proceedings may have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL.

## Development and Operational Risks

**NEE's and FPL's business, financial condition, results of operations and prospects could suffer if NEE and FPL do not proceed with projects under development or are unable to complete the construction of, or capital improvements to, electric generation, transmission and distribution facilities, gas infrastructure facilities or other facilities on schedule or within budget.**

NEE's and FPL's ability to proceed with projects under development and to complete construction of, and capital improvement projects for, their electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities on schedule and within budget may be adversely affected by escalating costs for materials and labor and regulatory compliance, inability to obtain or renew necessary licenses, rights-of-way, permits or other approvals on acceptable terms or on schedule, disputes involving contractors, labor organizations, land owners, governmental entities, environmental groups, Native American and aboriginal groups, lessors, joint venture partners and other third parties, negative publicity, transmission interconnection issues and other factors. If any development project or construction or capital improvement project is not completed, is delayed or is subject to cost overruns, certain associated costs may not be approved for recovery or otherwise be recoverable through regulatory mechanisms that may be available, and NEE and FPL could become obligated to make delay or termination payments or become obligated for other damages under contracts, could experience the loss of tax credits or tax incentives, or delayed or diminished returns, and could be required to write off all or a portion of their investment in the project. Any of these events could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE and FPL face risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements that may impede their development and operating activities.**

NEE and FPL own, develop, construct, manage and operate electric-generation and transmission facilities and natural gas transmission facilities. A key component of NEE's and FPL's growth is their ability to construct and operate generation and transmission facilities to meet customer needs. As part of these operations, NEE and FPL must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. Should NEE or FPL be unsuccessful in obtaining necessary licenses or permits on acceptable terms or resolving third-party challenges to such licenses or permits, should there be a delay in obtaining or renewing necessary licenses or permits or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances on NEE or FPL, NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected. Any failure to negotiate successful project development agreements for new facilities with third parties could have similar results.

**The operation and maintenance of NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities, retail gas distribution system in Florida and other facilities are subject to many operational risks, the consequences of which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.**

NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities, retail gas distribution system in Florida and other facilities are subject to many operational risks. Operational risks could result in, among other things, lost revenues due to prolonged outages, increased expenses due to monetary penalties or fines for compliance failures or legal claims, liability to third parties for property and personal injury damage or loss of life, a failure to perform under applicable power sales agreements or other agreements and associated loss of revenues from terminated agreements or liability for liquidated damages under continuing agreements, and replacement equipment costs or an obligation to purchase or generate replacement power at higher prices.

Uncertainties and risks inherent in operating and maintaining NEE's and FPL's facilities include, but are not limited to:

- risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned;
- failures in the availability, acquisition or transportation of fuel or other necessary supplies;
- the impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, hurricanes, tornadoes, icing events, floods, earthquakes and droughts;
- performance below expected or contracted levels of output or efficiency;
- breakdown or failure, including, but not limited to, explosions, fires, leaks or other major events, of equipment, transmission or distribution systems or pipelines;
- availability of replacement equipment;
- risks of property damage, human injury or loss of life from energized equipment, hazardous substances or explosions, fires, leaks or other events, especially where facilities are located near populated areas;

- potential environmental impacts of gas infrastructure operations;
- availability of adequate water resources and ability to satisfy water intake and discharge requirements;
- inability to identify, manage properly or mitigate equipment defects in NEE's and FPL's facilities;
- use of new or unproven technology;
- risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation, and lack of available alternative fuel sources;
- increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes; and
- insufficient insurance, warranties or performance guarantees to cover any or all lost revenues or increased expenses from the foregoing.

**NEE's and FPL's business, financial condition, results of operations and prospects may be negatively affected by a lack of growth or slower growth in the number of customers or in customer usage.**

Growth in customer accounts and growth of customer usage each directly influence the demand for electricity and the need for additional power generation and power delivery facilities, as well as the need for energy-related commodities such as natural gas. Customer growth and customer usage are affected by a number of factors outside the control of NEE and FPL, such as mandated energy efficiency measures, demand side management requirements, and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. A lack of growth, or a decline, in the number of customers or in customer demand for electricity or natural gas and other fuels may cause NEE and FPL to fail to fully realize the anticipated benefits from significant investments and expenditures and could have a material adverse effect on NEE's and FPL's growth, business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects can be materially adversely affected by weather conditions, including, but not limited to, the impact of severe weather.**

Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. In addition, severe weather and natural disasters, such as hurricanes, floods, tornadoes, icing events and earthquakes, can be destructive and cause power outages and property damage, reduce revenue, affect the availability of fuel and water, and require NEE and FPL to incur additional costs, for example, to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources. Furthermore, NEE's and FPL's physical plants could be placed at greater risk of damage should changes in the global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation and, particularly relevant to FPL, a change in sea level. FPL operates in the east and lower west coasts of Florida and Gulf Power operates in northwest Florida, areas that historically have been prone to severe weather events, such as hurricanes. A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent NEE and FPL from operating their business in the normal course and could result in any of the adverse consequences described above. Any of the foregoing could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

At FPL and other businesses of NEE where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

Changes in weather can also affect the production of electricity at power generation facilities, including, but not limited to, NEER's wind and solar facilities. For example, the level of wind resource affects the revenue produced by wind generation facilities. Because the levels of wind and solar resources are variable and difficult to predict, NEER's results of operations for individual wind and solar facilities specifically, and NEE's results of operations generally, may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected.

**Threats of terrorism and catastrophic events that could result from terrorism, cyberattacks, or individuals and/or groups attempting to disrupt NEE's and FPL's business, or the businesses of third parties, may materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.**

NEE and FPL are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyberattacks and other disruptive activities of individuals or groups. There have been cyberattacks within the energy industry on energy infrastructure such as substations, gas pipelines and related assets in the past and there may be such attacks in the future. NEE's and FPL's generation, transmission and distribution facilities, fuel storage facilities, information technology systems and other infrastructure facilities and systems could be direct targets of, or otherwise be materially adversely affected by, such activities.

Terrorist acts, cyberattacks or other similar events affecting NEE's and FPL's systems and facilities, or those of third parties on which NEE and FPL rely, could harm NEE's and FPL's business, for example, by limiting their ability to generate, purchase or transmit power, natural gas or other energy-related commodities, by limiting their ability to bill customers and collect and process payments, and by delaying their development and construction of new generation, distribution or transmission facilities or capital

improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues, significant additional costs (for example, to repair assets, implement additional security requirements, obtain or acquire insurance), significant fines and penalties, and reputational damage, could materially adversely affect NEE's and FPL's operations (for example, by contributing to disruption of supplies and markets for natural gas, oil and other fuels), and could impair NEE's and FPL's ability to raise capital (for example, by contributing to financial instability and lower economic activity). In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs. Such events or actions may materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

**The ability of NEE and FPL to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. NEE's and FPL's insurance coverage does not provide protection against all significant losses.**

Insurance coverage may not continue to be available or may not be available at rates or on terms similar to those presently available to NEE and FPL. The ability of NEE and FPL to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. If insurance coverage is not available or obtainable on acceptable terms, NEE or FPL may be required to pay costs associated with adverse future events. NEE and FPL generally are not fully insured against all significant losses. For example, FPL is not fully insured against hurricane-related losses, but could instead seek recovery of such uninsured losses from customers subject to approval by the FPSC, to the extent losses exceed restricted funds set aside to cover the cost of storm damage. A loss for which NEE or FPL is not fully insured could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE invests in gas and oil producing and transmission assets through NEER’s gas infrastructure business. The gas infrastructure business is exposed to fluctuating market prices of natural gas, natural gas liquids, oil and other energy commodities. A prolonged period of low gas and oil prices could impact NEER’s gas infrastructure business and cause NEER to delay or cancel certain gas infrastructure projects and could result in certain projects becoming impaired, which could materially adversely affect NEE's results of operations.**

Natural gas and oil prices are affected by supply and demand, both globally and regionally. Factors that influence supply and demand include operational issues, natural disasters, weather, political instability, conflicts, new discoveries, technological advances, economic conditions and actions by major oil-producing countries. There can be significant volatility in market prices for gas and oil, and price fluctuations could have a material effect on the financial performance of gas and oil producing and transmission assets. For example, in a low gas and oil price environment, NEER would generate less revenue from its gas infrastructure investments in gas and oil producing properties, and as a result certain investments might become less profitable or incur losses. Prolonged periods of low oil and gas prices could also result in the delay or cancellation of oil and gas production and transmission projects, could cause projects to experience lower returns, and could result in certain projects becoming impaired, which could materially adversely affect NEE's results of operations.

**If supply costs necessary to provide NEER's full energy and capacity requirement services are not favorable, operating costs could increase and materially adversely affect NEE's business, financial condition, results of operations and prospects.**

NEER provides full energy and capacity requirements services primarily to distribution utilities, which include load-following services and various ancillary services, to satisfy all or a portion of such utilities' power supply obligations to their customers. The supply costs for these transactions may be affected by a number of factors, including, but not limited to, events that may occur after such utilities have committed to supply power, such as weather conditions, fluctuating prices for energy and ancillary services, and the ability of the distribution utilities' customers to elect to receive service from competing suppliers. NEER may not be able to recover all of its increased supply costs, which could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

**Due to the potential for significant volatility in market prices for fuel, electricity and renewable and other energy commodities, NEER's inability or failure to manage properly or hedge effectively the commodity risks within its portfolios could materially adversely affect NEE's business, financial condition, results of operations and prospects.**

There can be significant volatility in market prices for fuel, electricity and renewable and other energy commodities. NEE's inability or failure to manage properly or hedge effectively its assets or positions against changes in commodity prices, volumes, interest rates, counterparty credit risk or other risk measures, based on factors that are either within, or wholly or partially outside of, NEE's control, may materially adversely affect NEE's business, financial condition, results of operations and prospects.

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**Reductions in the liquidity of energy markets may restrict the ability of NEE to manage its operational risks, which, in turn, could negatively affect NEE's results of operations.**

NEE is an active participant in energy markets. The liquidity of regional energy markets is an important factor in NEE's ability to manage risks in these operations. Market liquidity is driven in part by the number of active market participants. Liquidity in the energy markets can be adversely affected by price volatility, restrictions on the availability of credit and other factors, and any reduction in the liquidity of energy markets could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

**NEE's and FPL's hedging and trading procedures and associated risk management tools may not protect against significant losses.**

NEE and FPL have hedging and trading procedures and associated risk management tools, such as separate but complementary financial, credit, operational, compliance and legal reporting systems, internal controls, management review processes and other mechanisms. NEE and FPL are unable to assure that such procedures and tools will be effective against all potential risks, including, without limitation, employee misconduct. If such procedures and tools are not effective, this could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

**If price movements significantly or persistently deviate from historical behavior, NEE's and FPL's risk management tools associated with their hedging and trading procedures may not protect against significant losses.**

NEE's and FPL's risk management tools and metrics associated with their hedging and trading procedures, such as daily value at risk, earnings at risk, stop loss limits and liquidity guidelines, are based on historical price movements. Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing behavior, NEE and FPL are unable to assure that their risk management tools and metrics will be effective to protect against material adverse effects on their business, financial condition, results of operations and prospects.

**If power transmission or natural gas, nuclear fuel or other commodity transportation facilities are unavailable or disrupted, the ability for subsidiaries of NEE, including FPL, to sell and deliver power or natural gas may be limited.**

Subsidiaries of NEE, including FPL, depend upon power transmission and natural gas, nuclear fuel and other commodity transportation facilities, many of which they do not own. Occurrences affecting the operation of these facilities that may or may not be beyond the control of subsidiaries of NEE, including FPL, (such as severe weather or a generation or transmission facility outage, pipeline rupture, or sudden and significant increase or decrease in wind generation) may limit or halt their ability to sell and deliver power and natural gas, or to purchase necessary fuels and other commodities, which could materially adversely impact NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE and FPL are subject to credit and performance risk from customers, hedging counterparties and vendors.**

NEE and FPL are exposed to risks associated with the creditworthiness and performance of their customers, hedging counterparties and vendors under contracts for the supply of equipment, materials, fuel and other goods and services required for their business operations and for the construction and operation of, and for capital improvements to, their facilities. Adverse conditions in the energy industry or the general economy, as well as circumstances of individual customers, hedging counterparties and vendors, may adversely affect the ability of some customers, hedging counterparties and vendors to perform as required under their contracts with NEE and FPL.

If any hedging, vending or other counterparty fails to fulfill its contractual obligations, NEE and FPL may need to make arrangements with other counterparties or vendors, which could result in material financial losses, higher costs, untimely completion of power generation facilities and other projects, and/or a disruption of their operations. If a defaulting counterparty is in poor financial condition, NEE and FPL may not be able to recover damages for any contract breach.

**NEE and FPL could recognize financial losses or a reduction in operating cash flows if a counterparty fails to perform or make payments in accordance with the terms of derivative contracts or if NEE or FPL is required to post margin cash collateral under derivative contracts.**

NEE and FPL use derivative instruments, such as swaps, options, futures and forwards, some of which are traded in the OTC markets or on exchanges, to manage their commodity and financial market risks, and for NEE to engage in trading and marketing activities. Any failures by their counterparties to perform or make payments in accordance with the terms of those transactions could have a material adverse effect on NEE's or FPL's business, financial condition, results of operations and prospects. Similarly, any requirement for FPL or NEE to post margin cash collateral under its derivative contracts could have a material adverse effect on its business, financial condition, results of operations and prospects. These risks may be increased during periods of adverse market or economic conditions affecting the industry in which NEE and FPL participate.

**NEE and FPL are highly dependent on sensitive and complex information technology systems, and any failure or breach of those systems could have a material adverse effect on their business, financial condition, results of operations and prospects.**

NEE and FPL operate in a highly regulated industry that requires the continuous functioning of sophisticated information technology systems and network infrastructure. Despite NEE's and FPL's implementation of security measures, all of their technology systems are vulnerable to disability, failures or unauthorized access due to such activities. If NEE's or FPL's information technology systems were to fail or be breached, sensitive confidential and other data could be compromised and NEE and FPL could be unable to fulfill critical business functions.

NEE's and FPL's business is highly dependent on their ability to process and monitor, on a daily basis, a very large number of transactions, many of which are highly complex and cross numerous and diverse markets. Due to the size, scope, complexity and geographical reach of NEE's and FPL's business, the development and maintenance of information technology systems to keep track of and process information is critical and challenging. NEE's and FPL's operating systems and facilities may fail to operate properly or become disabled as a result of events that are either within, or wholly or partially outside of, their control, such as operator error, severe weather, terrorist activities or cyber incidents. Any such failure or disabling event could materially adversely affect NEE's and FPL's ability to process transactions and provide services, and their business, financial condition, results of operations and prospects.

NEE and FPL add, modify and replace information systems on a regular basis. Modifying existing information systems or implementing new or replacement information systems is costly and involves risks, including, but not limited to, integrating the modified, new or replacement system with existing systems and processes, implementing associated changes in accounting procedures and controls, and ensuring that data conversion is accurate and consistent. Any disruptions or deficiencies in existing information systems, or disruptions, delays or deficiencies in the modification or implementation of new information systems, could result in increased costs, the inability to track or collect revenues and the diversion of management's and employees' attention and resources, and could negatively impact the effectiveness of the companies' control environment, and/or the companies' ability to timely file required regulatory reports.

NEE and FPL also face the risks of operational failure or capacity constraints of third parties, including, but not limited to, those who provide power transmission and natural gas transportation services.

**NEE's and FPL's retail businesses are subject to the risk that sensitive customer data may be compromised, which could result in a material adverse impact to their reputation and/or have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL.**

NEE's and FPL's retail businesses require access to sensitive customer data in the ordinary course of business. NEE's and FPL's retail businesses may also need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center services, to the retail businesses. If a significant breach occurred, the reputation of NEE and FPL could be materially adversely affected, customer confidence could be diminished, or customer information could be subject to identity theft. NEE and FPL would be subject to costs associated with the breach and/or NEE and FPL could be subject to fines and legal claims, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL.

**NEE and FPL could recognize financial losses as a result of volatility in the market values of derivative instruments and limited liquidity in OTC markets.**

NEE and FPL execute transactions in derivative instruments on either recognized exchanges or via the OTC markets, depending on management's assessment of the most favorable credit and market execution factors. Transactions executed in OTC markets have the potential for greater volatility and less liquidity than transactions on recognized exchanges. As a result, NEE and FPL may not be able to execute desired OTC transactions due to such heightened volatility and limited liquidity.

In the absence of actively quoted market prices and pricing information from external sources, the valuation of derivative instruments involves management's judgment and use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these derivative instruments and have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE and FPL may be materially adversely affected by negative publicity.**

From time to time, political and public sentiment may result in a significant amount of adverse press coverage and other adverse public statements affecting NEE and FPL. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceeding, can divert the time and effort of senior management from NEE's and FPL's business.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputations of NEE and FPL, on the morale and performance of their employees and on their relationships with regulators. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects may be adversely affected if they are unable to maintain, negotiate or renegotiate franchise agreements on acceptable terms with municipalities and counties in Florida.**

Subsidiaries of NEE, including FPL, may negotiate franchise agreements with municipalities and counties in Florida to provide electric services within such municipalities and counties, and electricity sales generated pursuant to these agreements represent a very substantial portion of the subsidiary's revenues. If they are unable to maintain, negotiate or renegotiate such franchise agreements on acceptable terms, it could contribute to lower earnings and they may not fully realize the anticipated benefits from significant investments and expenditures, which could adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected by work strikes or stoppages and increasing personnel costs.**

Employee strikes or work stoppages could disrupt operations and lead to a loss of revenue and customers. Personnel costs may also increase due to inflationary or competitive pressures on payroll and benefits costs and revised terms of collective bargaining agreements with union employees. These consequences could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

**NEE's ability to successfully identify, complete and integrate acquisitions is subject to significant risks, including, but not limited to, the effect of increased competition for acquisitions resulting from the consolidation of the energy industry.**

NEE is likely to encounter significant competition for acquisition opportunities that may become available as a result of the consolidation of the energy industry in general. In addition, NEE may be unable to identify attractive acquisition opportunities at favorable prices and to complete and integrate them successfully and in a timely manner.

### Nuclear Generation Risks

**The operation and maintenance of NEE's and FPL's nuclear generation facilities involve environmental, health and financial risks that could result in fines or the closure of the facilities and in increased costs and capital expenditures.**

NEE's and FPL's nuclear generation facilities are subject to environmental, health and financial risks, including, but not limited to, those relating to site storage of spent nuclear fuel, the disposition of spent nuclear fuel, leakage and emissions of tritium and other radioactive elements in the event of a nuclear accident or otherwise, the threat of a terrorist attack or cyber incident and other potential liabilities arising out of the ownership or operation of the facilities. NEE and FPL maintain decommissioning funds and external insurance coverage which are intended to reduce the financial exposure to some of these risks; however, the cost of decommissioning nuclear generation facilities could exceed the amount available in NEE's and FPL's decommissioning funds, and the exposure to liability and property damages could exceed the amount of insurance coverage. If NEE or FPL is unable to recover the additional costs incurred through insurance or, in the case of FPL, through regulatory mechanisms, their business, financial condition, results of operations and prospects could be materially adversely affected.

**In the event of an incident at any nuclear generation facility in the U.S. or at certain nuclear generation facilities in Europe, NEE and FPL could be assessed significant retrospective assessments and/or retrospective insurance premiums as a result of their participation in a secondary financial protection system and nuclear insurance mutual companies.**

Liability for accidents at nuclear power plants is governed by the Price-Anderson Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both private sources and an industry retrospective payment plan. In accordance with this Act, NEE maintains the maximum amount of private liability insurance obtainable, and participates in a secondary financial protection system, which provides liability insurance coverage for an incident at any nuclear reactor in the U.S. Under the secondary financial protection system, NEE is subject to retrospective assessments and/or retrospective insurance premiums, plus any applicable taxes, for an incident at any nuclear reactor in the U.S. or at certain nuclear generation facilities in Europe, regardless of fault or proximity to the incident. Such assessments, if levied, could materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

**NRC orders or new regulations related to increased security measures and any future safety requirements promulgated by the NRC could require NEE and FPL to incur substantial operating and capital expenditures at their nuclear generation facilities and/or result in reduced revenues.**

The NRC has broad authority to impose licensing and safety-related requirements for the operation and maintenance of nuclear generation facilities, the addition of capacity at existing nuclear generation facilities and the construction of new nuclear generation facilities, and these requirements are subject to change. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a nuclear generation facility, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. Any of the foregoing events could require NEE and FPL to incur increased costs and capital expenditures, and could reduce revenues.

Any serious nuclear incident occurring at a NEE or FPL plant could result in substantial remediation costs and other expenses. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear generation facility. An incident at a nuclear facility anywhere in the world also could cause the NRC to impose additional conditions or other requirements on the industry, or on certain types of nuclear generation units, which could increase costs, reduce revenues and result in additional capital expenditures.

**The inability to operate any of NEE's or FPL's nuclear generation units through the end of their respective operating licenses, or in the case of Duane Arnold through expected shutdown, could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.**

If any of NEE's or FPL's nuclear generation facilities are not operated for any reason through the life of their respective operating licenses, or in the case of Duane Arnold through expected shutdown, NEE or FPL may be required to increase depreciation rates, incur impairment charges and accelerate future decommissioning expenditures, any of which could materially adversely affect their business, financial condition, results of operations and prospects.

**NEE's and FPL's nuclear units are periodically removed from service to accommodate planned refueling and maintenance outages, and for other purposes. If planned outages last longer than anticipated or if there are unplanned outages, NEE's and FPL's results of operations and financial condition could be materially adversely affected.**

NEE's and FPL's nuclear units are periodically removed from service to accommodate planned refueling and maintenance outages, including, but not limited to, inspections, repairs and certain other modifications as well as to replace equipment. In the event that a scheduled outage lasts longer than anticipated or in the event of an unplanned outage due to, for example, equipment failure, such outages could materially adversely affect NEE's or FPL's business, financial condition, results of operations and prospects.

### Liquidity, Capital Requirements and Common Stock Risks

**Disruptions, uncertainty or volatility in the credit and capital markets, among other factors, may negatively affect NEE's and FPL's ability to fund their liquidity and capital needs and to meet their growth objectives, and can also materially adversely affect the results of operations and financial condition of NEE and FPL.**

NEE and FPL rely on access to capital and credit markets as significant sources of liquidity for capital requirements and other operations requirements that are not satisfied by operating cash flows. Disruptions, uncertainty or volatility in those capital and credit markets could increase NEE's and FPL's cost of capital and affect their ability to fund their liquidity and capital needs and to meet their growth objectives. If NEE or FPL is unable to access regularly the capital and credit markets on terms that are reasonable, it may have to delay raising capital, issue shorter-term securities and incur an unfavorable cost of capital, which, in turn, could adversely affect its ability to grow its business, could contribute to lower earnings and reduced financial flexibility, and could have a material adverse effect on its business, financial condition, results of operations and prospects.

Although NEE's competitive energy and certain other subsidiaries have used non-recourse or limited-recourse, project-specific or other financing in the past, market conditions and other factors could adversely affect the future availability of such financing. The inability of NEE's subsidiaries, including, without limitation, NEECH and its subsidiaries, to access the capital and credit markets to provide project-specific or other financing for electric generation or other facilities or acquisitions on favorable terms, whether because of disruptions or volatility in those markets or otherwise, could necessitate additional capital raising or borrowings by NEE and/or NEECH in the future.

The inability of subsidiaries that have existing project-specific or other financing arrangements to meet the requirements of various agreements relating to those financings, as well as actions by third parties or lenders, could give rise to a project-specific financing default which, if not cured or waived, might result in the specific project, and potentially in some limited instances its parent companies, being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral. Such an occurrence also could result in NEE expending additional funds or incurring additional obligations over the shorter term to ensure continuing compliance with project-specific financing arrangements based upon the expectation of improvement in the project's performance or financial returns over the longer term. Any of these actions could materially adversely affect NEE's business, financial condition, results of operations and prospects, as well as the availability or terms of future financings for NEE or its subsidiaries.

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**NEE's, NEECH's and FPL's inability to maintain their current credit ratings may materially adversely affect NEE's and FPL's liquidity and results of operations, limit the ability of NEE and FPL to grow their business, and increase interest costs.**

The inability of NEE, NEECH and FPL to maintain their current credit ratings could materially adversely affect their ability to raise capital or obtain credit on favorable terms, which, in turn, could impact NEE's and FPL's ability to grow their business and service indebtedness and repay borrowings, and would likely increase their interest costs. In addition, certain agreements and guarantee arrangements would require posting of additional collateral in the event of a ratings downgrade. Some of the factors that can affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, NEE's overall business mix and political, legislative and regulatory actions. There can be no assurance that one or more of the ratings of NEE, NEECH and FPL will not be lowered or withdrawn entirely by a rating agency.

**NEE's and FPL's liquidity may be impaired if their credit providers are unable to fund their credit commitments to the companies or to maintain their current credit ratings.**

The inability of NEE's, NEECH's and FPL's credit providers to fund their credit commitments or to maintain their current credit ratings could require NEE, NEECH or FPL, among other things, to renegotiate requirements in agreements, find an alternative credit provider with acceptable credit ratings to meet funding requirements, or post cash collateral and could have a material adverse effect on NEE's and FPL's liquidity.

**Poor market performance and other economic factors could affect NEE's defined benefit pension plan's funded status, which may materially adversely affect NEE's and FPL's business, financial condition, liquidity and results of operations and prospects.**

NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. A decline in the market value of the assets held in the defined benefit pension plan due to poor investment performance or other factors may increase the funding requirements for this obligation.

NEE's defined benefit pension plan is sensitive to changes in interest rates, since as interest rates decrease, the funding liabilities increase, potentially increasing benefits costs and funding requirements. Any increase in benefits costs or funding requirements may have a material adverse effect on NEE's and FPL's business, financial condition, liquidity, results of operations and prospects.

**Poor market performance and other economic factors could adversely affect the asset values of NEE's and FPL's nuclear decommissioning funds, which may materially adversely affect NEE's and FPL's liquidity, financial condition and results of operations.**

NEE and FPL are required to maintain decommissioning funds to satisfy their future obligations to decommission their nuclear power plants. A decline in the market value of the assets held in the decommissioning funds due to poor investment performance or other factors may increase the funding requirements for these obligations. Any increase in funding requirements may have a material adverse effect on NEE's and FPL's liquidity, financial condition and results of operations.

**Certain of NEE's investments are subject to changes in market value and other risks, which may materially adversely affect NEE's liquidity, financial condition and results of operations.**

NEE holds certain investments where changes in the fair value affect NEE's financial results. In some cases there may be no observable market values for these investments, requiring fair value estimates to be based on other valuation techniques. This type of analysis requires significant judgment and the actual values realized in a sale of these investments could differ materially from those estimated. A sale of an investment below previously estimated value, or other decline in the fair value of an investment, could result in losses or the write-off of such investment, and may have a material adverse effect on NEE's liquidity, financial condition and results of operations.

**NEE may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to NEE.**

NEE is a holding company and, as such, has no material operations of its own. Substantially all of NEE's consolidated assets are held by its subsidiaries. NEE's ability to meet its financial obligations, including, but not limited to, its guarantees, and to pay dividends on its common stock is primarily dependent on its subsidiaries' net income and cash flows, which are subject to the risks of their respective businesses, and their ability to pay upstream dividends or to repay funds to NEE.

NEE's subsidiaries are separate legal entities and have no independent obligation to provide NEE with funds for its payment obligations. The subsidiaries have financial obligations, including, but not limited to, payment of debt service, which they must satisfy before they can provide NEE with funds. In addition, in the event of a subsidiary's liquidation or reorganization, NEE's right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors.

The dividend-paying ability of some of the subsidiaries is limited by contractual restrictions which are contained in outstanding financing agreements and which may be included in future financing agreements. The future enactment of laws or regulations also may prohibit or restrict the ability of NEE's subsidiaries to pay upstream dividends or to repay funds.

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**NEE may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if NEE is required to perform under guarantees of obligations of its subsidiaries.**

NEE guarantees many of the obligations of its consolidated subsidiaries, other than FPL, through guarantee agreements with NEECH. These guarantees may require NEE to provide substantial funds to its subsidiaries or their creditors or counterparties at a time when NEE is in need of liquidity to meet its own financial obligations. Funding such guarantees may materially adversely affect NEE's ability to meet its financial obligations or to pay dividends.

**NEP may not be able to access sources of capital on commercially reasonable terms, which would have a material adverse effect on its ability to consummate future acquisitions and on the value of NEE's limited partner interest in NEP OpCo.**

Through an indirect wholly owned subsidiary, NEE owns a limited partner interest in NEP OpCo. NEP's inability to access capital on commercially reasonable terms and effectively consummate future acquisitions could have a material adverse effect on NEP's ability to grow its cash distributions to its common unitholders, including NEE, and on the value of NEE's limited partnership interest in NEP OpCo. In addition, NEP's issuance of additional common units, securities convertible into NEP common units or other securities in connection with acquisitions could cause significant common unitholder dilution and reduce cash distributions to its common unitholders, including NEE, if the acquisitions are not sufficiently accretive.

**Disruptions, uncertainty or volatility in the credit and capital markets may exert downward pressure on the market price of NEE's common stock.**

The market price and trading volume of NEE's common stock are subject to fluctuations as a result of, among other factors, general credit and capital market conditions and changes in market sentiment regarding the operations, business and financing strategies of NEE and its subsidiaries. As a result, disruptions, uncertainty or volatility in the credit and capital markets may, for example, have a material adverse effect on the market price of NEE's common stock.

## Item 1B. Unresolved Staff Comments

None

## Item 2. Properties

See Item 1. Business - FPL and Item 1. Business - NEER for a description of principal properties.

### Character of Ownership

Substantially all of FPL's properties are subject to the lien of FPL's mortgage, which secures most debt securities issued by FPL. The majority of FPL's real property is held in fee and is free from other encumbrances, subject to minor exceptions which are not of a nature as to substantially impair the usefulness to FPL of such properties. Some of FPL's electric lines are located on parcels of land which are not owned in fee by FPL but are covered by necessary consents of governmental authorities or rights obtained from owners of private property. Subsidiaries within the NEER segment have ownership interests in entities that own generation facilities, pipeline facilities and transmission assets and a number of those facilities and assets are encumbered by liens securing various financings. Additionally, the majority of NEER's generation facilities, pipeline facilities and transmission lines are located on land under easement or leased from owners of private property. See Note 1 - Electric Plant, Depreciation and Amortization.

## Item 3. Legal Proceedings

None

## Item 4. Mine Safety Disclosures

Not applicable

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## Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

**Common Stock Data.** All of FPL's common stock is owned by NEE. NEE's common stock is traded on the New York Stock Exchange under the symbol "NEE." As of the close of business on January 31, 2020, there were 16,776 holders of record of NEE's common stock. The amount and timing of dividends payable on NEE's common stock are within the sole discretion of NEE's Board of Directors. The Board of Directors reviews the dividend rate at least annually (generally in February) to determine its appropriateness in light of NEE's financial position and results of operations, legislative and regulatory developments affecting the electric utility industry in general and FPL in particular, competitive conditions, change in business mix and any other factors the Board of Directors deems relevant. In February 2020, NEE announced that it would increase its quarterly dividend on its common stock from $1.25 per share to $1.40 per share.

**Issuer Purchases of Equity Securities.** Information regarding purchases made by NEE of its common stock during the three months ended December 31, 2019 is as follows:

| Period | Total Number of Shares Purchased[(a)] | Average Price Paid Per Share | Total Number of Shares Purchased as Part of a Publicly Announced Program | Maximum Number of Shares that May Yet be Purchased Under the Program[(b)] |
|---|---|---|---|---|
| 10/1/19 - 10/31/19 | — | — | — | 45,000,000 |
| 11/1/19 - 11/30/19 | 990 | $ 231.42 | — | 45,000,000 |
| 12/1/19 - 12/31/19 | 387 | $ 238.22 | — | 45,000,000 |
| Total | 1,377 | $ 233.33 | — | |

(a) Includes: (1) in November 2019, shares of common stock withheld from employees to pay certain withholding taxes upon the vesting of stock awards granted to such employees under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan; and (2) in December 2019, shares of common stock purchased as a reinvestment of dividends by the trustee of a grantor trust in connection with NEE's obligation under a February 2006 grant under the NextEra Energy, Inc. Amended and Restated Long-Term Incentive Plan (former LTIP) to an executive officer of deferred retirement share awards.

(b) In May 2017, NEE's Board of Directors authorized repurchases of up to 45 million shares of common stock over an unspecified period.

## Item 6. Selected Financial Data

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | 2016 | 2015 |
| | (millions, except per share amounts) | | | | |
| SELECTED DATA OF NEE[(a)]: | | | | | |
| Operating revenues | **$ 19,204** | $ 16,727 | $ 17,173 | $ 16,138 | $ 17,486 |
| Net income[(b)] | **$ 3,388** | $ 5,776 | $ 5,323 | $ 2,999 | $ 2,762 |
| Net income attributable to NEE[(b)(c)] | **$ 3,769** | $ 6,638 | $ 5,380 | $ 2,906 | $ 2,752 |
| Earnings per share attributable to NEE - basic[(b)(c)] | **$ 7.82** | $ 14.03 | $ 11.48 | $ 6.27 | $ 6.11 |
| Earnings per share attributable to NEE - assuming dilution[(b)(c)] | **$ 7.76** | $ 13.88 | $ 11.39 | $ 6.24 | $ 6.06 |
| Dividends paid per share of common stock | **$ 5.00** | $ 4.44 | $ 3.93 | $ 3.48 | $ 3.08 |
| Total assets[(d)] | **$ 117,691** | $ 103,702 | $ 97,963 | $ 90,474 | $ 82,479 |
| Long-term debt, excluding current portion | **$ 37,543** | $ 26,782 | $ 31,410 | $ 27,765 | $ 26,681 |
| Capital expenditures, independent power and other investments and nuclear fuel purchases: | | | | | |
| FPL | **$ 5,755** | $ 5,135 | $ 5,291 | $ 3,934 | $ 3,633 |
| Gulf Power | **729** | — | — | — | — |
| NEER[(e)] | **6,505** | 7,189 | 5,415 | 5,607 | 4,691 |
| Corporate and Other[(e)] | **4,473** | 680 | 34 | 95 | 53 |
| Total | **$ 17,462** | $ 13,004 | $ 10,740 | $ 9,636 | $ 8,377 |

(a) See Note 8 for a discussion of 2019 acquisitions and Note 1 - NextEra Energy Partners, LP for a discussion of the deconsolidation of NEP in January 2018.
(b) 2018 includes an after-tax gain of approximately $3.0 billion related to the deconsolidation of NEP (see Note 1 - NextEra Energy Partners, LP). 2017 includes approximately $1.8 billion ($1.9 billion attributable to NEE) of net favorable tax reform impacts (see Note 6). 2017 and 2016 include after-tax gains on the sale of the fiber-optic telecommunications business of $685 million (see Note 1 - Disposal of Businesses/Assets) and natural gas generation facilities of $219 million. Also, on an after-tax basis, 2017 includes an impairment charge of $258 million related to Duane Arnold (see Note 5 - Nonrecurring Fair Value Measurements).
(c) 2018 reflects approximately $497 million relating to a reduction of differential membership interests as a result of a change in the federal corporate income tax rate effective January 1, 2018 (see Note 1 - Sales of Differential Membership Interests).
(d) Includes assets held for sale of approximately $440 million in 2019 related to two solar generation facilities and $452 million in 2016 related to a fiber-optic telecommunications business (see Note 1 - Disposal of Businesses/Assets) and $1,009 million in 2015 related to merchant natural gas generation facilities.
(e) Prior year amounts have been adjusted as discussed in Note 16.

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

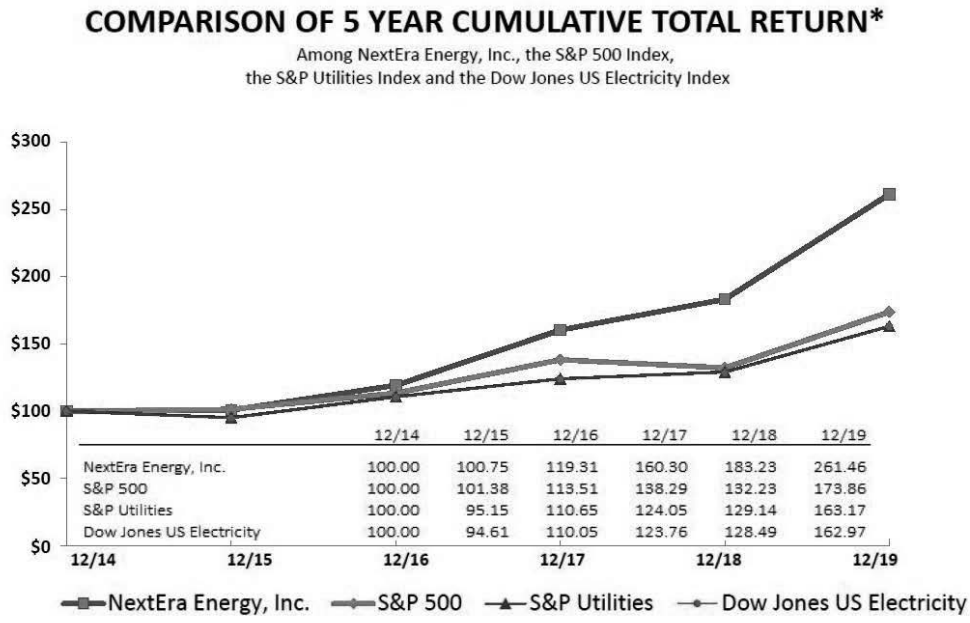
### OVERVIEW

NEE's operating performance is driven primarily by the operations of its two principal businesses, FPL, which serves more than five million customer accounts in Florida and is one of the largest electric utilities in the U.S., and NEER, which together with affiliated entities is the world's largest generator of renewable energy from the wind and sun based on 2019 MWh produced on a net generation basis. The table below presents net income (loss) attributable to NEE and earnings (loss) per share attributable to NEE, assuming dilution, by reportable segment, FPL and NEER, as well as Gulf Power, acquired in January 2019 (see Note 8 - Gulf Power Company) and Corporate and Other, which is primarily comprised of the operating results of other business activities, as well as other income and expense items, including interest expense, and eliminating entries. See Note 16 for additional segment information, including a discussion of a change in segment reporting. The following discussion should be read in conjunction with the Notes to Consolidated Financial Statements contained herein and all comparisons are with the corresponding items in the prior year. Certain 2018 and 2017 segment amounts have been retrospectively adjusted as discussed in Note 16.

| | Net Income (Loss) Attributable to NEE | | | Earnings (Loss) Per Share Attributable to NEE, Assuming Dilution | | |
|---|---|---|---|---|---|---|
| | Years Ended December 31, | | | Years Ended December 31, | | |
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| | (millions) | | | | | |
| FPL | **$ 2,334** | $ 2,171 | $ 1,880 | **$ 4.81** | $ 4.55 | $ 3.98 |
| Gulf Power[a] | **180** | — | — | **0.37** | — | — |
| NEER[b][c][d] | **1,807** | 4,704 | 2,997 | **3.72** | 9.82 | 6.34 |
| Corporate and Other[d] | **(552)** | (237) | 503 | **(1.14)** | (0.49) | 1.07 |
| NEE[c] | **$ 3,769** | $ 6,638 | $ 5,380 | **$ 7.76** | $ 13.88 | $ 11.39 |

(a) Gulf Power was acquired in January 2019. See Note 8 - Gulf Power Company.
(b) NEER's results reflect an allocation of interest expense from NEECH based on a deemed capital structure of 70% debt and differential membership interests sold by NextEra Energy Resources' subsidiaries.
(c) NEP was deconsolidated from NEER in January 2018. See Note 1 - NextEra Energy Partners, LP.
(d) NEER's and Corporate and Other's results for 2018 and 2017 were retrospectively adjusted to reflect a segment change. See Note 16.

For the five years ended December 31, 2019, NEE delivered a total shareholder return of approximately 161.5%, above the S&P 500's 73.9% return, the S&P 500 Utilities' 63.2% return and the Dow Jones U.S. Electricity's 63.0% return. The historical stock performance of NEE's common stock shown in the performance graph below is not necessarily indicative of future stock price performance.




*$100 invested on 12/31/14 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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## Adjusted Earnings

NEE prepares its financial statements under GAAP. However, management uses earnings adjusted for certain items (adjusted earnings), a non-GAAP financial measure, internally for financial planning, analysis of performance, reporting of results to the Board of Directors and as an input in determining performance-based compensation under NEE's employee incentive compensation plans. NEE also uses adjusted earnings when communicating its financial results and earnings outlook to analysts and investors. NEE's management believes that adjusted earnings provide a more meaningful representation of NEE's fundamental earnings power. Although these amounts are properly included in the determination of net income under GAAP, management believes that the amount and/or nature of such items make period to period comparisons of operations difficult and potentially confusing. Adjusted earnings do not represent a substitute for net income, as prepared under GAAP.

The following table provides details of the after-tax adjustments to net income considered in computing NEE's adjusted earnings discussed above.

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| | | (millions) | |
| Net losses associated with non-qualifying hedge activity[(a)] | **$ (404)** | $ (186) | $ (37) |
| Tax reform-related, including the impact of tax rate change on differential membership interests[(b)] | **$ (89)** | $ 436 | $ 1,881 |
| NEP investment gains, net[(c)] | **$ 96** | $ 2,863 | $ — |
| Change in unrealized gains (losses) on NEER's nuclear decommissioning funds and OTTI, net[(d)] | **$ 176** | $ (125) | $ 2 |
| Acquisition-related[(e)] | **$ (70)** | $ (14) | $ (63) |
| Operating results of solar projects in Spain - NEER | **$ (2)** | $ (9) | $ 5 |
| Gain on sale of the fiber-optic telecommunications business - Corporate and Other[(f)] | **$ —** | $ — | $ 685 |
| Duane Arnold impairment charge[(g)] | **$ —** | $ — | $ (258) |

(a) For 2019, 2018 and 2017, approximately $63 million of losses, $41 million of gains, and $46 million of gains, respectively, are included in NEER's net income; the balance is included in Corporate and Other. The change in non-qualifying hedge activity is primarily attributable to changes in forward power and natural gas prices, interest rates and foreign currency exchange rates, as well as the reversal of previously recognized unrealized mark-to-market gains or losses as the underlying transactions were realized. In 2017, net losses associated with non-qualifying hedge activity were partly offset by approximately $95 million of tax reform impacts.

(b) For 2019, approximately $89 million related to the impact of tax rate change on differential membership interests relates to NEER. For 2018, approximately $421 million of favorable tax reform-related impacts, including the impact of tax rate change on differential membership interests, relates to NEER and the balance relates to Corporate and Other. For 2017, approximately $1,929 million of net favorable tax reform impacts and $50 million of net unfavorable tax reform impacts relate to NEER and FPL, respectively; the balance relates to Corporate and Other. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery and - Sales of Differential Membership Interests and Note 6.

(c) For 2019 and 2018, approximately $96 million and $2,885 million, respectively, relates to NEER; the 2018 balance relates to Corporate and Other. See Note 1 - NextEra Energy Partners, LP and - Disposal of Businesses/Assets.

(d) For 2019, 2018 and 2017, approximately $176 million of gains, $127 million of losses, and $2 million of gains, respectively, are included in NEER's net income; the balance for 2018 is included in Corporate and Other.

(e) For 2019, approximately $44 million, $20 million and $6 million of costs are included in Corporate and Other's, Gulf Power's and NEER's net income, respectively. For 2018, $9 million of costs are included in Corporate and Other's net income; the balance is included in NEER. For 2017, the costs relate to Corporate and Other. See Note 1 - Acquisition-Related.

(f) See Note 1 - Disposal of Businesses/Assets for a discussion of the sale of the fiber-optic telecommunications business.

(g) Approximately $246 million of the impairment charge is included in NEER's net income; the balance is included in Corporate and Other. See Note 5 - Nonrecurring Fair Value Measurements.

NEE segregates into two categories unrealized mark-to-market gains and losses and timing impacts related to derivative transactions. The first category, referred to as non-qualifying hedges, represents certain energy derivative, interest rate derivative and foreign currency transactions entered into as economic hedges, which do not meet the requirements for hedge accounting, or for which hedge accounting treatment is not elected or has been discontinued. Changes in the fair value of those transactions are marked to market and reported in the consolidated statements of income, resulting in earnings volatility because the economic offset to certain of the positions are generally not marked to market. As a consequence, NEE's net income reflects only the movement in one part of economically-linked transactions. For example, a gain (loss) in the non-qualifying hedge category for certain energy derivatives is offset by decreases (increases) in the fair value of related physical asset positions in the portfolio or contracts, which are not marked to market under GAAP. For this reason, NEE's management views results expressed excluding the impact of the non-qualifying hedges as a meaningful measure of current period performance. The second category, referred to as trading activities, which is included in adjusted earnings, represents the net unrealized effect of actively traded positions entered into to take advantage of expected market price movements and all other commodity hedging activities. At FPL, substantially all changes in the fair value of energy derivative transactions are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel clause. See Note 4.

**2019 Summary**

Net income attributable to NEE for 2019 was lower than 2018 by $2,869 million, or $6.12 per share, assuming dilution, due to lower results at NEER and Corporate and Other, partly offset by higher results at FPL and the addition of results from Gulf Power.

FPL's increase in net income in 2019 was primarily driven by continued investments in plant in service and other property.

NEER's results decreased in 2019 primarily reflecting the absence of the 2018 NEP investment gains upon deconsolidation and the favorable adjustment to differential membership interests recognized in 2018 related to the decrease in federal corporate income tax rate effective January 1, 2018. These decreases were partly offset by 2019 net unrealized gains on equity securities held in NEER's nuclear decommissioning funds compared to net unrealized losses in 2018 and higher contributions from new investments. In 2019, NEER added approximately 1,125 MW of new wind generating capacity, 1,091 MW of wind repowering generating capacity and 512 MW of solar generating capacity in the U.S. and increased its backlog of contracted renewable development projects.

During 2019, Gulf Power contributed $180 million of net income attributable to NEE.

Corporate and Other's results in 2019 decreased primarily due to higher interest costs, unfavorable non-qualifying hedge activity, as well as acquisition and integration costs incurred in 2019.

NEE and its subsidiaries require funds to support and grow their businesses. These funds are primarily provided by cash flows from operations, borrowings or issuances of short- and long-term debt, proceeds from differential membership investors, sales of assets to NEP or third parties and, from time to time, issuances of equity securities. See Liquidity and Capital Resources - Liquidity.

## RESULTS OF OPERATIONS

Net income attributable to NEE for 2019 was $3.77 billion compared to $6.64 billion in 2018. In 2019, net income attributable to NEE declined primarily due to lower results at NEER and Corporate and Other, partly offset by higher results at FPL and the addition of results from Gulf Power. The comparison of the results of operations for the years ended December 31, 2018 and 2017 are included in Management's Discussion in NEE's and FPL's Annual Report on Form 10-K for the year ended December 31, 2018.

In June 2019, subsidiaries within the NEER segment sold ownership interests in three wind generation facilities and three solar generation facilities with a total net generating capacity of approximately 611 MW to a subsidiary of NEP. See Note 1 - Disposal of Businesses/Assets.

In July 2019, a wholly owned subsidiary of NEET acquired the outstanding membership interests of an entity that indirectly owns Trans Bay, which owns and operates a 53-mile, high-voltage direct current underwater transmission cable system in California. See Note 8 - Trans Bay Cable, LLC.

NEE's effective income tax rates for the years ended December 31, 2019 and 2018 were approximately 12% and 21%, respectively. The decrease in the rate primarily reflects the amortization of deferred regulatory credits, primarily at FPL, the impact of higher tax credits, an adjustment related to differential membership interests and lower pre-tax income. See Note 6.

### FPL: Results of Operations

FPL obtains its operating revenues primarily from the sale of electricity to retail customers at rates established by the FPSC through base rates and cost recovery clause mechanisms. FPL’s net income for 2019 and 2018 was $2,334 million and $2,171 million, respectively, representing an increase of $163 million. The increase was primarily driven by higher earnings from investments in plant in service and other property. Such investments grew FPL's average retail rate base by approximately $3.3 billion in 2019 and reflect, among other things, solar generation additions, ongoing transmission and distribution additions and investments in FPL's generation infrastructure, including the Okeechobee Clean Energy Center, which achieved commercial operation during the first quarter of 2019.

In September 2017, Hurricane Irma passed through Florida causing damage throughout much of FPL's service territory. In December 2017, following the enactment of tax reform, FPL used available reserve amortization to offset nearly all of the storm restoration costs that were expensed, and FPL is partially restoring the reserve amortization through tax savings generated during the term of the 2016 rate agreement. In September 2019, FPL’s service territory was impacted by Hurricane Dorian. In December 2019, FPL determined that it would not seek recovery of the costs incurred as a result of Hurricane Dorian through a storm surcharge from customers and instead recorded such costs as storm restoration costs in NEE’s and FPL’s consolidated statements of income. All of the Hurricane Dorian storm restoration costs were offset by utilization of available reserve amortization resulting from operational efficiencies generated at the business. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery.

The use of reserve amortization is permitted by the 2016 rate agreement. See Item 1. Business - FPL - FPL Regulation - FPL Electric Rate Regulation - Base Rates for additional information on the 2016 rate agreement. In order to earn a targeted regulatory ROE, subject to limitations associated with the 2016 rate agreement, reserve amortization is calculated using a trailing thirteen-month average of retail rate base and capital structure in conjunction with the trailing twelve months regulatory retail base net

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operating income, which primarily includes the retail base portion of base and other revenues, net of O&M, depreciation and amortization, interest and tax expenses. In general, the net impact of these income statement line items must be offset, in part, by reserve amortization to earn the targeted regulatory ROE. In certain periods, reserve amortization is reversed so as not to exceed the targeted regulatory ROE. The drivers of FPL's net income not reflected in the reserve amortization calculation typically include wholesale and transmission service revenues and expenses, cost recovery clause revenues and expenses, AFUDC - equity and revenue and costs not recoverable from retail customers by the FPSC. In 2019 and 2018, FPL recorded the reversal of reserve amortization of approximately $357 million and $541 million, respectively. FPL's regulatory ROE for both 2019 and 2018 was approximately 11.60%.

During 2019, FPL's operating revenues increased $330 million primarily related to higher retail base revenues of $323 million, higher revenues of $60 million as a result of the acquisition of the entity that operates Florida City Gas in July 2018 and other increases associated with various cost recovery clause revenues, partly offset by $78 million in lower storm-related revenues.

Retail Base

FPL's retail base revenues for 2019 and 2018 reflect the 2016 rate agreement. In December 2016, the FPSC issued a final order approving the 2016 rate agreement which became effective January 2017 and will remain in effect until at least December 2020, establishes FPL's allowed regulatory ROE at 10.55%, with a range of 9.60% to 11.60%, and allowed for retail rate base increases in 2017, 2018, and upon commencement of commercial operations at the Okeechobee Clean Energy Center and certain solar projects. See Item 1. Business - FPL - FPL Regulation - FPL Electric Rate Regulation - Base Rates for additional information on the 2016 rate agreement.

The increase in retail base revenues in 2019 primarily reflects additional revenues of approximately $210 million related to retail base rate increases associated with the Okeechobee Clean Energy Center and the 2019 addition of new solar generation. In 2019, retail base revenues were also impacted by a decrease of 0.3% in the average usage per retail customer and an increase of 2.0% in the average number of customer accounts. Although the weather in 2019 was favorable when compared to 2018, usage per retail customer decreased slightly. See Note 1 - Rate Regulation.

Cost Recovery Clauses

Revenues from fuel and other cost recovery clauses and pass-through costs, such as franchise fees, revenue taxes and storm-related surcharges, are largely a pass-through of costs. Such revenues also include a return on investment allowed to be recovered through the cost recovery clauses on certain assets, primarily related to certain solar and environmental projects and the unamortized balance of the regulatory asset associated with FPL's acquisition of certain generation facilities. See Item 1. Business - FPL - FPL Regulation - FPL Electric Rate Regulation - Cost Recovery Clauses. Underrecovery or overrecovery of cost recovery clause and other pass-through costs (deferred clause and franchise expenses and revenues) can significantly affect NEE's and FPL's operating cash flows. The 2019 net overrecovery impacting NEE and FPL's operating cash flows was approximately $188 million.

Storm-related revenues decreased in 2019 primarily as a result of the conclusion of the storm-recovery bond surcharge in the third quarter of 2019. See Note 9 - FPL.

In 2019 and 2018, cost recovery clauses contributed approximately $117 million and $113 million, respectively, to FPL's net income.

Other Items Impacting FPL's Consolidated Statements of Income

*Storm Restoration Costs*
In December 2019, FPL determined that it would not seek recovery of Hurricane Dorian storm restoration costs through a surcharge from customers and instead recorded such costs as storm restoration costs in NEE's and FPL's consolidated statements of income. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery.

*Depreciation and Amortization Expense*
The major components of FPL's depreciation and amortization expense are as follows:

| | Years Ended December 31, | |
|---|---|---|
| | **2019** | 2018 |
| | (millions) | |
| Reserve reversal recorded under the 2016 rate agreement | **$ 357** | $ 541 |
| Other depreciation and amortization recovered under base rates (excluding reserve amortization) and other | **1,876** | 1,739 |
| Depreciation and amortization primarily recovered under cost recovery clauses and securitized storm-recovery cost amortization | **291** | 353 |
| Total | **$ 2,524** | $ 2,633 |

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Depreciation expense decreased $109 million during 2019 primarily reflecting a lower reversal of reserve amortization in 2019 compared to 2018 and lower storm-recovery cost amortization primarily as a result of the final payment of the storm-recovery bonds in the third quarter 2019 (see Note 9 - FPL). Reserve amortization, or reversal of such amortization, reflects adjustments to accrued asset removal costs provided under the 2016 rate agreement in order to achieve the targeted regulatory ROE. Reserve amortization is recorded as a reduction to (or when reversed as an increase to) accrued asset removal costs which is reflected in noncurrent regulatory liabilities on the consolidated balance sheets. At December 31, 2019, approximately $893 million remains in accrued asset removal costs related to reserve amortization. The decreases in depreciation and amortization expense were driven by partly offset by increased depreciation related to higher plant in service balances.

## NEER: Results of Operations

NEER owns, develops, constructs, manages and operates electric generation facilities in wholesale energy markets primarily in the U.S., as well as in Canada. NEER also provides full energy and capacity requirements services, engages in power and gas marketing and trading activities, owns and operates rate-regulated transmission facilities and transmission lines and invests in natural gas, natural gas liquids and oil production and pipeline infrastructure assets. NEER's net income less net loss attributable to noncontrolling interests for 2019 and 2018 was $1,807 million and $4,704 million, respectively, resulting in a decrease in 2019 of $2,897 million. The primary drivers, on an after-tax basis, of the change are in the following table.

| | Increase (Decrease) From Prior Period |
|---|---|
| | Year Ended December 31, 2019 |
| | (millions) |
| New investments[(a)] | **$ 260** |
| Existing assets[(a)] | **(17)** |
| Gas infrastructure[(a)] | **61** |
| Customer supply and proprietary power and gas trading[(b)] | **24** |
| NEET[(b)] | **20** |
| Asset sales/abandonment | **(83)** |
| Interest and other general and administrative expenses[(c)] | **(172)** |
| Other, including other investment income and income taxes | **104** |
| Change in non-qualifying hedge activity[(d)] | **(104)** |
| Change in unrealized gains/losses on equity securities held in nuclear decommissioning funds and OTTI, net[(d)] | **303** |
| Tax reform-related, including the impact of tax rate change on differential membership interests[(d)] | **(510)** |
| NEP investment gains, net[(d)] | **(2,789)** |
| Operating results of the solar projects in Spain[(d)] | **7** |
| Acquisition-related[(d)] | **(1)** |
| Decrease in net income less net loss attributable to noncontrolling interests | **$ (2,897)** |

(a) Reflects after-tax project contributions, including the net effect of deferred income taxes and other benefits associated with PTCs and ITCs for wind and solar projects, as applicable (see Note 1 - Income Taxes and - Sales of Differential Membership Interests and Note 6), but excludes allocation of interest expense or corporate general and administrative expenses. Results from projects and pipelines are included in new investments during the first twelve months of operation or ownership. Project results are included in existing assets and pipeline results are included in gas infrastructure beginning with the thirteenth month of operation or ownership.
(b) Excludes allocation of interest expense and corporate general and administrative expenses.
(c) Includes differential membership interest costs. Excludes unrealized mark-to-market gains and losses related to interest rate derivative contracts, which are included in change in non-qualifying hedge activity.
(d) See Overview - Adjusted Earnings for additional information.

### New Investments

In 2019, results from new investments increased primarily due to higher earnings, including the net effect of deferred income taxes and other benefits associated with PTCs and ITCs, related to the addition of wind and solar generating projects during or after 2018.

### Other Factors

Supplemental to the primary drivers of the changes in NEER's net income less net loss attributable to noncontrolling interests discussed above, the discussion below describes changes in certain line items set forth in NEE's consolidated statements of income as they relate to NEER.

*Operating Revenues*
Operating revenues for 2019 increased $655 million primarily due to:
- favorable unrealized mark-to-market activity of $295 million from non-qualifying hedges,
- revenues from new investments of $232 million,
- higher revenues of $198 million from the customer supply and proprietary power and gas trading business, and
- higher revenues of $122 million from the gas infrastructure business,

partly offset by,

- lower revenues from existing assets of $226 million primarily related to the absence of revenues of certain wind and solar facilities sold to NEP in December 2018 and June 2019 and lower wind resource as compared to 2018.

*Operating Expenses - net*

Operating expenses - net for 2019 increased $19 million primarily due to:

- higher fuel and depreciation expense of $150 million primarily related to the customer supply and proprietary power and gas trading and gas infrastructure businesses,
- higher operating expenses associated with new investments of approximately $137 million, and
- an impairment charge of approximately $72 million in 2019 related to the decision to no longer move forward with the construction of a wind facility (see Note 1 - Construction Activity),

partly offset by,

- higher net gains on the disposal of businesses/assets of $320 million, primarily related to the gain recognized on the sale of ownership interests in wind and solar projects to NEP (see Note 1 - Disposal of Businesses/Assets).

*Interest Expense*

NEER's interest expense for 2019 increased $278 million primarily reflecting unfavorable impacts of approximately $251 million related to changes in the fair value of interest rate derivative instruments and higher borrowing costs to support growth in the business.

*Equity in Earnings of Equity Method Investees*

Lower earnings from equity method investees in 2019 primarily reflects equity in losses of NEP primarily related to unfavorable impacts related to changes in the fair value of interest rate derivative instruments and the absence of approximately $150 million related to a 2018 favorable adjustment at NEP to the differential membership interests due to the decrease in the federal corporate income tax rate. The decrease was partly offset by increased equity in earnings of other equity method investees.

*Gain on NEP Deconsolidation*

The NEP deconsolidation resulted in a gain of approximately $3.9 billion ($3.0 billion after tax) in NEE's consolidated statements of income during 2018. See Note 1 - NextEra Energy Partners, LP.

*Change in Unrealized Gains (Losses) on Equity Securities Held in NEER's Nuclear Decommissioning Funds - net*

Changes in the fair value of equity securities in NEER's nuclear decommissioning funds, primarily equity securities in NEER's special use funds, relate to favorable market conditions in 2019 compared to 2018.

*Tax Credits, Benefits and Expenses*

PTCs from wind projects and ITCs from solar and certain wind projects are reflected in NEER's earnings. PTCs are recognized as wind energy is generated and sold based on a per kWh rate prescribed in applicable federal and state statutes, and were approximately $75 million and $88 million in 2019 and 2018, respectively. ITCs totaled approximately $199 million and $131 million in 2019 and 2018, respectively. A portion of the PTCs and ITCs have been allocated to investors in connection with sales of differential membership interests. PTCs and ITCs can significantly affect the effective income tax rate depending on the amount of pretax income. The amount of PTCs recognized can be significantly affected by wind generation and by PTC roll off. See Note 6.

*Net Loss Attributable to Noncontrolling Interests*

Net loss attributable to noncontrolling interests primarily represents the activity related to the sales of differential membership interests. The decrease for 2019 primarily reflects the absence of a 2018 adjustment of approximately $497 million ($373 million after-tax) related to the decrease in federal corporate income tax rate effective January 1, 2018.

## Gulf Power: Results of Operations

Following its acquisition in January 2019, Gulf Power contributed approximately $180 million of net income attributable to NEE for 2019. Gulf Power's operating revenues were approximately $1,487 million and operating expenses totaled $1,216 million for 2019.

## Corporate and Other: Results of Operations

Corporate and Other is primarily comprised of the operating results of other business activities, as well as corporate interest income and expenses. Corporate and Other allocates a portion of NEECH's corporate interest expense to NEER. Interest expense is allocated based on a deemed capital structure of 70% debt and differential membership interests sold by NextEra Energy Resources' subsidiaries.

Corporate and Other's results decreased $315 million during 2019 primarily reflecting higher interest costs associated with higher debt balances primarily related to the Gulf Power acquisition financing, higher after-tax losses of approximately $114 million related to non-qualifying hedge activity, as well as higher acquisition and integration costs incurred in 2019.

## LIQUIDITY AND CAPITAL RESOURCES

NEE and its subsidiaries require funds to support and grow their businesses. These funds are used for, among other things, working capital, capital expenditures, investments in or acquisitions of assets and businesses, payment of maturing debt obligations and, from time to time, redemption or repurchase of outstanding debt or equity securities. It is anticipated that these requirements will be satisfied through a combination of cash flows from operations, short- and long-term borrowings, the issuance of short- and long-term debt and, from time to time, equity securities, proceeds from differential membership investors and sales of assets to NEP or third parties, consistent with NEE's and FPL's objective of maintaining, on a long-term basis, a capital structure that will support a strong investment grade credit rating. NEE, FPL and NEECH rely on access to credit and capital markets as significant sources of liquidity for capital requirements and other operations that are not satisfied by operating cash flows. The inability of NEE, FPL and NEECH to maintain their current credit ratings could affect their ability to raise short- and long-term capital, their cost of capital and the execution of their respective financing strategies, and could require the posting of additional collateral under certain agreements.

In October 2015, NEE authorized a program to purchase, from time to time, up to $150 million of common units representing limited partner interests in NEP. Under the program, purchases may be made in amounts, at prices and at such times as NEE or its subsidiaries deem appropriate, all subject to market conditions and other considerations. The purchases may be made in the open market or in privately negotiated transactions. Any purchases will be made in such quantities, at such prices, in such manner and on such terms and conditions as determined by NEE or its subsidiaries in their discretion, based on factors such as market and business conditions, applicable legal requirements and other factors. The common unit purchase program does not require NEE to acquire any specific number of common units and may be modified or terminated by NEE at any time. The purpose of the program is not to cause NEP's common units to be delisted from the New York Stock Exchange or to cause the common units to be deregistered with the SEC. As of December 31, 2019, NEE had purchased approximately $36 million of NEP common units under this program. At December 31, 2019, NEE owned a noncontrolling general partner interest in NEP and beneficially owned approximately 59.9% of NEP's voting power.

## Cash Flows

NEE's sources and uses of cash for 2019, 2018 and 2017 were as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| | | (millions) | |
| Sources of cash: | | | |
| Cash flows from operating activities | **$ 8,155** | $ 6,593 | $ 6,458 |
| Issuances of long-term debt | **13,919** | 4,399 | 8,354 |
| Proceeds from differential membership investors | **1,604** | 1,841 | 1,414 |
| Proceeds from sale of the fiber-optic telecommunications business | **—** | — | 1,454 |
| Sale of independent power and other investments of NEER | **1,163** | 1,617 | 178 |
| Issuances of common stock - net | **1,494** | 718 | 55 |
| Net increase in commercial paper and other short-term debt[(a)] | **—** | 6,272 | 1,867 |
| Proceeds from issuance of NEP convertible preferred units - net | **—** | — | 548 |
| Non-operating distributions from equity method investees | **—** | 637 | 7 |
| Other sources - net | **274** | 123 | 220 |
| Total sources of cash | **26,609** | 22,200 | 20,555 |
| Uses of cash: | | | |
| Capital expenditures, acquisitions, independent power and other investments and nuclear fuel purchases | **(17,462)** | (13,004) | (10,740) |
| Retirements of long-term debt | **(5,492)** | (3,102) | (6,780) |
| Net decrease in commercial paper and other short-term debt[(a)] | **(4,799)** | — | — |
| Payments to related parties under a cash sweep and credit support agreement – net | **(54)** | (21) | — |
| Dividends | **(2,408)** | (2,101) | (1,845) |
| Other uses - net | **(543)** | (695) | (762) |
| Total uses of cash | **(30,758)** | (18,923) | (20,127) |
| Effects of currency translation on cash, cash equivalents and restricted cash | **4** | (7) | 26 |
| Net increase (decrease) in cash, cash equivalents and restricted cash[(a)] | **$ (4,145)** | $ 3,270 | $ 454 |

(a) 2019 and 2018 amounts relate to the acquisition of Gulf Power. See Note 8 - Gulf Power Company.

NEE's primary capital requirements are for expanding and enhancing FPL's and Gulf Power's electric system and generation facilities to continue to provide reliable service to meet customer electricity demands and for funding NEER's investments in independent power and other projects. See Note 15 - Commitments for estimated capital expenditures in 2020 through 2024. The following table provides a summary of the major capital investments for 2019, 2018 and 2017.

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| | | (millions) | |
| FPL: | | | |
| Generation: | | | |
| New | **$ 1,242** | $ 976 | $ 1,198 |
| Existing | **1,215** | 1,142 | 1,285 |
| Transmission and distribution | **2,893** | 2,456 | 2,151 |
| Nuclear fuel | **195** | 123 | 117 |
| General and other | **550** | 334 | 431 |
| Other, primarily change in accrued property additions and exclusion of AFUDC - equity | **(340)** | 104 | 109 |
| Total | **5,755** | 5,135 | 5,291 |
| Gulf Power | **729** | — | — |
| NEER[(a)]: | | | |
| Wind | **1,974** | 4,093 | 2,824 |
| Solar | **1,741** | 698 | 759 |
| Nuclear, including nuclear fuel | **179** | 233 | 220 |
| Natural gas pipelines | **687** | 873 | 785 |
| Other gas infrastructure | **969** | 893 | 681 |
| Other (2019 primarily related to acquisitions, see Note 8) | **955** | 399 | 146 |
| Total | **6,505** | 7,189 | 5,415 |
| Corporate and Other (2019 primarily related to acquisitions, see Note 8)[(a)] | **4,473** | 680 | 34 |
| Total capital expenditures, independent power and other investments and nuclear fuel purchases | **$ 17,462** | $ 13,004 | $ 10,740 |

(a) Amounts for 2018 and 2017 were retrospectively adjusted to reflect a segment change. See Note 16.

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## Liquidity

At December 31, 2019, NEE's total net available liquidity was approximately $8.5 billion. The table below provides the components of FPL's, Gulf Power's and NEECH's net available liquidity at December 31, 2019.

| | FPL | Gulf Power | NEECH | Total | Maturity Date FPL | Maturity Date Gulf Power | Maturity Date NEECH |
|---|---|---|---|---|---|---|---|
| | (millions) | | | | | | |
| Syndicated revolving credit facilities[(a)] | $ 2,943 | $ 900 | $ 5,297 | $ 9,140 | 2020 - 2024 | 2024 | 2021 - 2024 |
| Issued letters of credit | (3) | — | (212) | (215) | | | |
| | 2,940 | 900 | 5,085 | 8,925 | | | |
| Bilateral revolving credit facilities | 680 | — | 1,075 | 1,755 | 2020 - 2022 | | 2020 - 2023 |
| Borrowings | — | — | — | — | | | |
| | 680 | — | 1,075 | 1,755 | | | |
| Letter of credit facilities[(b)] | — | — | 900 | 900 | | | 2020 - 2021 |
| Issued letters of credit | — | — | (793) | (793) | | | |
| | — | — | 107 | 107 | | | |
| Subtotal | 3,620 | 900 | 6,267 | 10,787 | | | |
| Cash and cash equivalents | 77 | 6 | 515 | 598 | | | |
| Commercial paper and other short-term borrowings outstanding | (1,482) | (392) | (1,042) | (2,916) | | | |
| Net available liquidity | $ 2,215 | $ 514 | $ 5,740 | $ 8,469 | | | |

(a) Provide for the funding of loans up to the amount of the credit facility and the issuance of letters of credit up to $2,525 million ($575 million for FPL, $75 million for Gulf Power and $1,875 million for NEECH). The entire amount of the credit facilities is available for general corporate purposes and to provide additional liquidity in the event of a loss to the companies' or their subsidiaries' operating facilities (including, in the case of FPL, a transmission and distribution property loss). FPL's syndicated revolving credit facilities are also available to support the purchase of $948 million of pollution control, solid waste disposal and industrial development revenue bonds (tax exempt bonds) in the event they are tendered by individual bondholders and not remarketed prior to maturity, as well as, the repayment of approximately $236 million of floating rate notes in the event an individual noteholder requires repayment prior to maturity. Gulf Power's syndicated revolving credit facilities are also available to support the purchase of approximately $269 million of its tax exempt bonds in the event they are tendered by individual bondholders and not remarketed prior to maturity. Approximately $2,314 million of FPL's and $4,109 million of NEECH's syndicated revolving credit facilities expire in 2024.

(b) Only available for the issuance of letters of credit.

At December 31, 2019, 73 banks participate in FPL's, Gulf Power's and NEECH's revolving credit facilities, with no one bank providing more than 6% of the combined revolving credit facilities. European banks provide approximately 25% of the combined revolving credit facilities. Pursuant to a 1998 guarantee agreement, NEE guarantees the payment of NEECH's debt obligations under its revolving credit facilities. In order for FPL, Gulf Power or NEECH to borrow or to have letters of credit issued under the terms of their respective revolving credit facilities and, also for NEECH, its letter of credit facilities, FPL, in the case of FPL, Gulf Power in the case of Gulf Power, and NEE, in the case of NEECH, are required, among other things, to maintain a ratio of funded debt to total capitalization that does not exceed a stated ratio. The FPL, Gulf Power and NEECH revolving credit facilities also contain default and related acceleration provisions relating to, among other things, failure of FPL, Gulf Power and NEE, as the case may be, to maintain the respective ratio of funded debt to total capitalization at or below the specified ratio. At December 31, 2019, each of NEE, Gulf Power and FPL was in compliance with its required ratio.

### Capital Support

*Guarantees, Letters of Credit, Surety Bonds and Indemnifications (Guarantee Arrangements)*

Certain subsidiaries of NEE issue guarantees and obtain letters of credit and surety bonds, as well as provide indemnities, to facilitate commercial transactions with third parties and financings. Substantially all of the guarantee arrangements are on behalf of NEE's consolidated subsidiaries, as discussed in more detail below. NEE is not required to recognize liabilities associated with guarantee arrangements issued on behalf of its consolidated subsidiaries unless it becomes probable that they will be required to perform. At December 31, 2019, NEE believes that there is no material exposure related to these guarantee arrangements.

NEE subsidiaries issue guarantees related to equity contribution agreements associated with the development, construction and financing of certain power generation facilities, engineering, procurement and construction agreements and equity contributions associated with natural gas pipeline projects under development and construction and a related natural gas transportation agreement. Commitments associated with these activities are included in the contracts table in Note 15.

In addition, at December 31, 2019, NEE subsidiaries had approximately $3.6 billion in guarantees related to obligations under purchased power agreements, nuclear-related activities, payment obligations related to PTCs, as well as other types of contractual obligations.

In some instances, subsidiaries of NEE elect to issue guarantees instead of posting other forms of collateral required under certain financing arrangements, as well as for other project-level cash management activities. At December 31, 2019, these guarantees totaled approximately $375 million and support, among other things, cash management activities, including those related to debt service and O&M service agreements, as well as other specific project financing requirements.

Subsidiaries of NEE also issue guarantees to support customer supply and proprietary power and gas trading activities, including the buying and selling of wholesale and retail energy commodities. At December 31, 2019, the estimated mark-to-market exposure (the total amount that these subsidiaries of NEE could be required to fund based on energy commodity market prices at December 31, 2019) plus contract settlement net payables, net of collateral posted for obligations under these guarantees totaled approximately $733 million.

At December 31, 2019, subsidiaries of NEE also had approximately $1.5 billion of standby letters of credit and approximately $562 million of surety bonds to support certain of the commercial activities discussed above. FPL's and NEECH's credit facilities are available to support the amount of the standby letters of credit.

In addition, as part of contract negotiations in the normal course of business, certain subsidiaries of NEE have agreed and in the future may agree to make payments to compensate or indemnify other parties, including those associated with asset divestitures, for possible unfavorable financial consequences resulting from specified events. The specified events may include, but are not limited to, an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretations of the tax law, or the triggering of cash grant recapture provisions under the Recovery Act. NEE is unable to estimate the maximum potential amount of future payments under some of these contracts because events that would obligate them to make payments have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence.

Certain guarantee arrangements described above contain requirements for NEECH and FPL to maintain a specified credit rating. For a discussion of credit rating downgrade triggers, see Credit Ratings below. NEE has guaranteed certain payment obligations of NEECH, including most of its debt and all of its debentures and commercial paper issuances, as well as most of its payment guarantees and indemnifications, and NEECH has guaranteed certain debt and other obligations of subsidiaries within the NEER segment.

*Shelf Registration*

In July 2018, NEE, NEECH and FPL filed a shelf registration statement with the SEC for an unspecified amount of securities, which became effective upon filing. The amount of securities issuable by the companies is established from time to time by their respective boards of directors. Securities that may be issued under the registration statement include, depending on the registrant, senior debt securities, subordinated debt securities, junior subordinated debentures, first mortgage bonds, common stock, preferred stock, stock purchase contracts, stock purchase units, warrants and guarantees related to certain of those securities.

## Contractual Obligations and Estimated Capital Expenditures

NEE's commitments at December 31, 2019 were as follows:

| | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| | | | | (millions) | | | |
| Long-term debt, including interest:[a] | | | | | | | |
| FPL[b] | $ 612 | $ 646 | $ 1,685 | $ 1,082 | $ 1,199 | $ 20,337 | $ 25,561 |
| Gulf Power[b] | 226 | 345 | 179 | 68 | 35 | 1,741 | 2,594 |
| NEER | 382 | 423 | 383 | 534 | 454 | 4,326 | 6,502 |
| Corporate and Other | 2,390 | 4,305 | 3,169 | 1,210 | 2,816 | 19,790 | 33,680 |
| Purchase obligations: | | | | | | | |
| FPL[c] | 7,320 | 7,310 | 7,105 | 7,020 | 7,310 | 11,625 | 47,690 |
| Gulf Power[c] | 800 | 770 | 645 | 650 | 680 | — | 3,545 |
| NEER[d] | 3,355 | 395 | 255 | 130 | 140 | 1,413 | 5,688 |
| Elimination of FPL's purchase obligations to NEER[d] | (108) | (105) | (102) | (99) | (97) | (1,314) | (1,825) |
| Asset retirement activities:[e] | | | | | | | |
| FPL[f] | 34 | 32 | 39 | 22 | 22 | 10,650 | 10,799 |
| Gulf Power | 5 | 15 | 1 | 1 | 1 | 98 | 121 |
| NEER[g] | 24 | 45 | 26 | 18 | 12 | 11,332 | 11,457 |
| Other commitments:[h] | | | | | | | |
| FPL | 13 | 12 | 12 | 8 | 5 | 42 | 92 |
| Gulf Power | 64 | 64 | 64 | 27 | — | — | 219 |
| NEER[i] | 36 | 46 | 41 | 38 | 41 | 704 | 906 |
| Total | $ 15,153 | $ 14,303 | $ 13,502 | $ 10,709 | $12,618 | $ 80,744 | $ 147,029 |

(a) Includes principal, interest, interest rate contracts and payments by NEE under stock purchase contracts. Variable rate interest was computed using December 31, 2019 rates. See Note 12.

(b) Includes tax exempt bonds at FPL of approximately $9 million in 2020, $46 million in 2021, $96 million in 2022, $15 million in 2023, $146 in 2024 and $636 million thereafter and at Gulf Power of approximately $41 million in 2022 and $228 million after 2024 that permit individual bondholders to tender the bonds for purchase at any time prior to maturity. In the event bonds are tendered for purchase, they would be remarketed by a designated remarketing agent in accordance with the related indenture. If the remarketing is unsuccessful, FPL and Gulf Power, as the case may be, would be required to purchase the tax exempt bonds. As of December 31, 2019, all of FPL's and Gulf Power's tax exempt bonds tendered for purchase had been successfully remarketed. Also includes at FPL floating rate notes of approximately $236 million maturing after 2024 that permit individual noteholders to require repayment prior to maturity. FPL's syndicated revolving credit facilities are available to support the purchase of tax exempt bonds and the repayment of floating rate notes. Gulf Power's syndicated revolving credit facilities are available to support the purchase of Gulf Power's tax exempt bonds.

(c) Represents projected capital expenditures through 2024, as well as, for FPL, required minimum payments primarily under long-term fuel transportation contracts (see Note 15 - Commitments and - Contracts).

(d) See Note 15 - Contracts.

(e) Represents expected cash payments adjusted for inflation for estimated costs to perform asset retirement activities.

(f) At December 31, 2019, FPL had approximately $4,697 million in restricted funds (included in NEE's and FPL's special use funds) for the payment of its portion of future expenditures to decommission the Turkey Point and St. Lucie nuclear units. See Note 13.

(g) At December 31, 2019, NEER had approximately $2,183 million in restricted funds (included in NEE's special use funds) for the payment of its portion of future expenditures to decommission Seabrook, Duane Arnold and Point Beach nuclear units. See Note 13.

(h) Includes lease payment obligations. See Note 14.

(i) Includes payments related to the acquisition of certain development rights.

## Credit Ratings

NEE's liquidity, ability to access credit and capital markets, cost of borrowings and collateral posting requirements under certain agreements is dependent on its and its subsidiaries credit ratings. At February 14, 2020, Moody's Investors Service, Inc. (Moody's), S&P Global Ratings (S&P) and Fitch Ratings, Inc. (Fitch) had assigned the following credit ratings to NEE, FPL and NEECH:

| | Moody's[a] | S&P[a] | Fitch[a] |
|---|---|---|---|
| NEE:[b] | | | |
| Corporate credit rating | Baa1 | A- | A- |
| FPL:[b] | | | |
| Corporate credit rating | A1 | A | A |
| First mortgage bonds | Aa2 | A+ | AA- |
| Senior unsecured notes | A1 | A | A+ |
| Pollution control, solid waste disposal and industrial development revenue bonds[c] | VMIG-1/P-1 | A-1 | F1 |
| Commercial paper | P-1 | A-1 | F1 |
| NEECH:[b] | | | |
| Corporate credit rating | Baa1 | A- | A- |
| Debentures | Baa1 | BBB+ | A- |
| Junior subordinated debentures | Baa2 | BBB | BBB |
| Commercial paper | P-2 | A-2 | F2 |

(a) A security rating is not a recommendation to buy, sell or hold securities and should be evaluated independently of any other rating. The rating is subject to revision or withdrawal at any time by the assigning rating organization.
(b) The outlook indicated by each of Moody's, S&P and Fitch is stable.
(c) Short-term ratings are presented as all bonds outstanding are currently paying a short-term interest rate. At FPL's election, a portion or all of the bonds may be adjusted to a long-term interest rate.

NEE and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt. A change in ratings is not an event of default under applicable debt instruments, and while there are conditions to drawing on the credit facilities noted above, the maintenance of a specific minimum credit rating is not a condition to drawing on these credit facilities.

Commitment fees and interest rates on loans under these credit facilities' agreements are tied to credit ratings. A ratings downgrade also could reduce the accessibility and increase the cost of commercial paper and other short-term debt issuances and borrowings and additional or replacement credit facilities. In addition, a ratings downgrade could result in, among other things, the requirement that NEE subsidiaries post collateral under certain agreements and guarantee arrangements, including, but not limited to, those related to fuel procurement, power sales and purchases, nuclear decommissioning funding, debt-related reserves and trading activities. FPL's, Gulf Power's and NEECH's credit facilities are available to support these potential requirements.

## Covenants

NEE's charter does not limit the dividends that may be paid on its common stock. As a practical matter, the ability of NEE to pay dividends on its common stock is dependent upon, among other things, dividends paid to it by its subsidiaries. For example, FPL pays dividends to NEE in a manner consistent with FPL's long-term targeted capital structure. However, the mortgage securing FPL's first mortgage bonds contains provisions which, under certain conditions, restrict the payment of dividends to NEE and the issuance of additional first mortgage bonds. Additionally, in some circumstances, the mortgage restricts the amount of retained earnings that FPL can use to pay cash dividends on its common stock. The restricted amount may change based on factors set out in the mortgage. Other than this restriction on the payment of common stock dividends, the mortgage does not restrict FPL's use of retained earnings. At December 31, 2019, no retained earnings were restricted by these provisions of the mortgage and, in light of FPL's current financial condition and level of earnings, management does not expect that planned financing activities or dividends would be affected by these limitations.

FPL may issue first mortgage bonds under its mortgage subject to its meeting an adjusted net earnings test set forth in the mortgage, which generally requires adjusted net earnings to be at least twice the annual interest requirements on, or at least 10% of the aggregate principal amount of, FPL's first mortgage bonds including those to be issued and any other non-junior FPL indebtedness. At December 31, 2019, coverage for the 12 months ended December 31, 2019 would have been approximately 8.2 times the annual interest requirements and approximately 3.7 times the aggregate principal requirements. New first mortgage bonds are also limited to an amount equal to the sum of 60% of unfunded property additions after adjustments to offset property retirements, the amount of retired first mortgage bonds or qualified lien bonds and the amount of cash on deposit with the mortgage trustee. At December 31, 2019, FPL could have issued in excess of $22 billion of additional first mortgage bonds based on the unfunded property additions and retired first mortgage bonds. At December 31, 2019, no cash was deposited with the mortgage trustee for these purposes.

In September 2006, NEE and NEECH executed a Replacement Capital Covenant (as amended, September 2006 RCC) in connection with NEECH's offering of $350 million principal amount of Series B Enhanced Junior Subordinated Debentures due 2066 (Series B junior subordinated debentures). The September 2006 RCC is for the benefit of persons that buy, hold or sell a specified series

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of long-term indebtedness (covered debt) of NEECH (other than the Series B junior subordinated debentures) or, in certain cases, of NEE. NEECH's 3.625% Debentures, Series due June 15, 2023 have been designated as the covered debt under the September 2006 RCC. The September 2006 RCC provides that NEECH may redeem, and NEE or NEECH may purchase, any Series B junior subordinated debentures on or before October 1, 2036, only to the extent that the redemption or purchase price does not exceed a specified amount of proceeds from the sale of qualifying securities, subject to certain limitations described in the September 2006 RCC. Qualifying securities are securities that have equity-like characteristics that are the same as, or more equity-like than, the Series B junior subordinated debentures at the time of redemption or purchase, which are sold within 365 days prior to the date of the redemption or repurchase of the Series B junior subordinated debentures.

In June 2007, NEE and NEECH executed a Replacement Capital Covenant (as amended, June 2007 RCC) in connection with NEECH's offering of $400 million principal amount of its Series C Junior Subordinated Debentures due 2067 (Series C junior subordinated debentures). The June 2007 RCC is for the benefit of persons that buy, hold or sell a specified series of covered debt of NEECH (other than the Series C junior subordinated debentures) or, in certain cases, of NEE. NEECH's 3.625% Debentures, Series due June 15, 2023 have been designated as the covered debt under the June 2007 RCC. The June 2007 RCC provides that NEECH may redeem or purchase, or satisfy, discharge or defease (collectively, defease), and NEE and any majority-owned subsidiary of NEE or NEECH may purchase, any Series C junior subordinated debentures on or before June 15, 2037, only to the extent that the principal amount defeased or the applicable redemption or purchase price does not exceed a specified amount raised from the issuance, during the 365 days prior to the date of that redemption, purchase or defeasance, of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Series C junior subordinated debentures at the time of redemption, purchase or defeasance, subject to certain limitations described in the June 2007 RCC.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

NEE's significant accounting policies are described in Note 1 to the consolidated financial statements, which were prepared under GAAP. Critical accounting policies are those that NEE believes are both most important to the portrayal of its financial condition and results of operations, and require complex, subjective judgments, often as a result of the need to make estimates and assumptions about the effect of matters that are inherently uncertain. Judgments and uncertainties affecting the application of those policies may result in materially different amounts being reported under different conditions or using different assumptions.

NEE considers the following policies to be the most critical in understanding the judgments that are involved in preparing its consolidated financial statements:

### Accounting for Derivatives and Hedging Activities

NEE uses derivative instruments (primarily swaps, options, futures and forwards) to manage the physical and financial risks inherent in the purchase and sale of fuel and electricity, as well as interest rate and foreign currency exchange rate risk associated primarily with outstanding and expected future debt issuances and borrowings. In addition, NEE, through NEER, uses derivatives to optimize the value of its power generation and gas infrastructure assets and engages in power and gas marketing and trading activities to take advantage of expected future favorable price movements.

#### Nature of Accounting Estimates

Accounting pronouncements require the use of fair value accounting if certain conditions are met, which may require significant judgment to measure the fair value of assets and liabilities. This applies not only to traditional financial derivative instruments, but to any contract having the accounting characteristics of a derivative. As a result, significant judgment must be used in applying derivatives accounting guidance to contracts. In the event changes in interpretation occur, it is possible that contracts that currently are excluded from derivatives accounting rules would have to be recorded on the balance sheet at fair value, with changes in the fair value recorded in the statement of income.

#### Assumptions and Accounting Approach

Derivative instruments, when required to be marked to market, are recorded on the balance sheet at fair value using a combination of market and income approaches. Fair values for some of the longer-term contracts where liquid markets are not available are derived through the use of industry-standard valuation techniques, such as internally developed models which estimate the fair value of a contract by calculating the present value of the difference between the contract price and the forward prices. Forward prices represent the price at which a buyer or seller could contract today to purchase or sell a commodity at a future date. The near-term forward market for electricity is generally liquid and therefore the prices in the early years of the forward curves reflect observable market quotes. However, in the later years, the market is much less liquid and forward price curves must be developed using factors including the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place, and a fundamental forecast of expected spot prices based on modeled supply and demand in the region. NEE estimates the fair value of interest rate and foreign currency derivatives using an income approach based on a discounted cash flows valuation technique utilizing the net

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amount of estimated future cash inflows and outflows related to the derivative agreements. The assumptions in these models are critical since any changes therein could have a significant impact on the fair value of the derivative.

At FPL, substantially all changes in the fair value of energy derivative transactions are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel clause. See Note 4.

In NEE's non-rate regulated operations, predominantly NextEra Energy Resources, essentially all changes in the derivatives' fair value for power purchases and sales, fuel sales and trading activities are recognized on a net basis in operating revenues; fuel purchases used in the production of electricity are recognized in fuel, purchased power and interchange expense; and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income.

For interest rate and foreign currency derivative instruments, essentially all changes in the derivatives' fair value are recognized in interest expense and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income. NEE estimates the fair value of these derivatives using an income approach based on a discounted cash flows valuation technique utilizing observable inputs.

Certain derivative transactions at NEER are entered into as economic hedges but the transactions do not meet the requirements for hedge accounting, hedge accounting treatment is not elected or hedge accounting has been discontinued. Changes in the fair value of those transactions are marked to market and reported in the consolidated statements of income, resulting in earnings volatility. These changes in fair value are reflected in the non-qualifying hedge category in computing adjusted earnings and could be significant to NEER's results because the economic offset to the positions are not marked to market. As a consequence, NEE's net income reflects only the movement in one part of economically-linked transactions. For example, a gain (loss) in the non-qualifying hedge category for certain energy derivatives is offset by decreases (increases) in the fair value of related physical asset positions in the portfolio or contracts, which are not marked to market under GAAP. For this reason, NEE's management views results expressed excluding the unrealized mark-to-market impact of the non-qualifying hedges as a meaningful measure of current period performance. For additional information regarding derivative instruments, see Note 4, Overview and Energy Marketing and Trading and Market Risk Sensitivity.

## Accounting for Pension Benefits

NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. Management believes that, based on actuarial assumptions and the well-funded status of the pension plan, NEE will not be required to make any cash contributions to the qualified pension plan in the near future. The qualified pension plan has a fully funded trust dedicated to providing benefits under the plan. NEE allocates net periodic income associated with the pension plan to its subsidiaries annually using specific criteria.

### Nature of Accounting Estimates

For the pension plan, the benefit obligation is the actuarial present value, as of the December 31 measurement date, of all benefits attributed by the pension benefit formula to employee service rendered to that date. The amount of benefit to be paid depends on a number of future events incorporated into the pension benefit formula, including an estimate of the average remaining life of employees/survivors as well as the average years of service rendered. The projected benefit obligation is measured based on assumptions concerning future interest rates and future employee compensation levels. NEE derives pension income from actuarial calculations based on the plan's provisions and various management assumptions including discount rate, rate of increase in compensation levels and expected long-term rate of return on plan assets.

### Assumptions and Accounting Approach

Accounting guidance requires recognition of the funded status of the pension plan in the balance sheet, with changes in the funded status recognized in other comprehensive income within shareholders' equity in the year in which the changes occur. Since NEE is the plan sponsor, and its subsidiaries do not have separate rights to the plan assets or direct obligations to their employees, this accounting guidance is reflected at NEE and not allocated to the subsidiaries. The portion of previously unrecognized actuarial gains and losses and prior service costs or credits that are estimated to be allocable to FPL as net periodic (income) cost in future periods and that otherwise would be recorded in AOCI are classified as regulatory assets and liabilities at NEE in accordance with regulatory treatment.

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Net periodic pension income is calculated using a number of actuarial assumptions. Those assumptions for the years ended December 31, 2019, 2018 and 2017 include:

| | 2019 | 2018 | 2017 |
|---|---|---|---|
| Discount rate | **4.26%** | 3.59% | 4.09% |
| Salary increase | **4.40%** | 4.10% | 4.10% |
| Expected long-term rate of return, net of investment management fees | **7.35%** | 7.35% | 7.35% |

In developing these assumptions, NEE evaluated input, including other qualitative and quantitative factors, from its actuaries and consultants, as well as information available in the marketplace. In addition, for the expected long-term rate of return on pension plan assets, NEE considered different models, capital market return assumptions and historical returns for a portfolio with an equity/bond asset mix similar to its pension fund, as well as its pension fund's historical compounded returns. NEE believes that 7.35% is a reasonable long-term rate of return, net of investment management fees, on its pension plan assets. NEE will continue to evaluate all of its actuarial assumptions, including its expected rate of return, at least annually, and will adjust them as appropriate.

NEE utilizes in its determination of pension income a market-related valuation of plan assets. This market-related valuation reduces year-to-year volatility and recognizes investment gains or losses over a five-year period following the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of plan assets and the actual return realized on those plan assets. Since the market-related value of plan assets recognizes gains or losses over a five-year period, the future value of plan assets will be affected as previously deferred gains or losses are recognized. Such gains and losses together with other differences between actual results and the estimates used in the actuarial valuations are deferred and recognized in determining pension income only to the extent they exceed 10% of the greater of projected benefit obligations or the market-related value of plan assets.

The following table illustrates the effect on net periodic pension income of changing the critical actuarial assumptions discussed above, while holding all other assumptions constant:

| | | Decrease in 2019 Net Periodic Pension Income | |
|---|---|---|---|
| | Change in Assumption | NEE | FPL |
| | | (millions) | |
| Expected long-term rate of return | (0.5)% | $ (22) | $ (14) |
| Discount rate | 0.5% | $ (2) | $ (1) |
| Salary increase | 0.5% | $ (2) | $ (1) |

NEE also utilizes actuarial assumptions about mortality to help estimate obligations of the pension plan. NEE has adopted the latest revised mortality tables and mortality improvement scales released by the Society of Actuaries, which did not have a material impact on the pension plan's obligation.

See Note 3.

## Carrying Value of Long-Lived Assets

NEE evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable.

Nature of Accounting Estimates

The amount of future net cash flows, the timing of the cash flows and the determination of an appropriate interest rate all involve estimates and judgments about future events. In particular, the aggregate amount of cash flows determines whether an impairment exists, and the timing of the cash flows is critical in determining fair value. Because each assessment is based on the facts and circumstances associated with each long-lived asset, the effects of changes in assumptions cannot be generalized.

Assumptions and Accounting Approach

An impairment loss is required to be recognized if the carrying value of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset’s fair value. In most instances, the fair value is determined by discounting estimated future cash flows using an appropriate interest rate. See Note 5 - Nonrecurring Fair Value Measurements.

**Decommissioning and Dismantlement**

NEE accounts for asset retirement obligations and conditional asset retirement obligations (collectively, AROs) under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as part of the carrying amount of the long-lived assets. NEE's AROs relate primarily to decommissioning obligations of FPL's and NEER's nuclear units and to obligations for the dismantlement of certain of NEER's wind and solar facilities.

Nature of Accounting Estimates

The calculation of the future cost of retiring long-lived assets, including nuclear decommissioning and plant dismantlement costs, involves estimating the amount and timing of future expenditures and making judgments concerning whether or not such costs are considered a legal obligation. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned and how costs will escalate with inflation. In addition, NEE also makes interest rate and rate of return projections on its investments in determining recommended funding requirements for nuclear decommissioning costs. Periodically, NEE is required to update these estimates and projections which can affect the annual expense amounts recognized, the liabilities recorded and the annual funding requirements for nuclear decommissioning costs. For example, an increase of 0.25% in the assumed escalation rates for nuclear decommissioning costs would increase NEE's AROs at December 31, 2019 by approximately $254 million.

Assumptions and Accounting Approach

*FPL* - For ratemaking purposes, FPL accrues and funds for nuclear plant decommissioning costs over the expected service life of each unit based on studies that are approved by the FPSC. The most recent studies, filed in 2015, reflect, among other things, the expiration dates of the operating licenses for FPL's nuclear units at the time of the studies. After giving effect to the recent license extensions for Turkey Point Units Nos. 3 and 4, FPL's portion of the future cost of decommissioning its four nuclear units, including spent fuel storage above what is expected to be refunded by the DOE under a spent fuel settlement agreement, is estimated to be approximately $9.7 billion, or $3.3 billion expressed in 2019 dollars. FPL intends to reflect the operating license extensions for Turkey Point Units Nos. 3 and 4 in its next nuclear decommissioning studies.

FPL accrues the cost of dismantling its fossil and solar plants over the expected service life of each unit based on studies filed with the FPSC. Unlike nuclear decommissioning, dismantlement costs are not funded. The most recent studies became effective January 1, 2017. At December 31, 2019, FPL's portion of the ultimate cost to dismantle its fossil and solar units is approximately $1.2 billion, or $510 million expressed in 2019 dollars. The majority of the dismantlement costs are not reported as AROs. FPL accrues for interim removal costs over the life of the related assets based on depreciation studies approved by the FPSC. Any differences between the amount of the ARO and the amount recorded for ratemaking purposes are reported as a regulatory liability in accordance with regulatory accounting.

The components of FPL's decommissioning of nuclear plants, dismantlement of plants and other accrued asset removal costs are as follows:

| | Nuclear Decommissioning | | Fossil/Solar Dismantlement | | Interim Removal Costs and Other | | Total | |
|---|---|---|---|---|---|---|---|---|
| | December 31, | | December 31, | | December 31, | | December 31, | |
| | **2019** | 2018 | **2019** | 2018 | **2019** | 2018 | **2019** | 2018 |
| | (millions) | | | | | | | |
| AROs | **$ 2,076** | $ 2,045 | **$ 186** | $ 97 | **$ 6** | $ 6 | **$ 2,268** | $ 2,148 |
| Less capitalized ARO asset net of accumulated depreciation | **225** | 316 | **48** | 33 | **1** | 1 | **274** | 350 |
| Accrued asset removal costs[(a)] | **368** | 319 | **144** | 164 | **645** | 489 | **1,157** | 972 |
| Asset retirement obligation regulatory expense difference[(a)] | **2,904** | 2,358 | **(72)** | (3) | **(4)** | (3) | **2,828** | 2,352 |
| Accrued decommissioning, dismantlement and other accrued asset removal costs[(b)] | **$ 5,123** | $ 4,406 | **$ 210** | $ 225 | **$ 646** | $ 491 | **$ 5,979** | $ 5,122 |

(a) Included in noncurrent regulatory liabilities on NEE's and FPL's consolidated balance sheets. See Note 1 - Rate Regulation.
(b) Represents total amount accrued for ratemaking purposes.

*NEER* - NEER records liabilities for the present value of its expected nuclear plant decommissioning costs which are determined using various internal and external data and applying a probability percentage to a variety of scenarios regarding the life of the plant and timing of decommissioning. The liabilities are being accreted using the interest method through the date decommissioning activities are expected to be complete. At December 31, 2019 and 2018, the AROs for decommissioning of NEER's nuclear plants approximated $623 million and $588 million, respectively. NEER's portion of the ultimate cost of decommissioning its nuclear plants, including costs associated with spent fuel storage above what is expected to be refunded by the DOE under a spent fuel settlement agreement, is estimated to be approximately $9.5 billion, or $2.0 billion expressed in 2019 dollars.

See Note 1 - Asset Retirement Obligations and - Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs and Note 13.

## Regulatory Accounting

Certain of NEE's businesses are subject to rate regulation which results in the recording of regulatory assets and liabilities. See Note 1 - Rate Regulation for a detail of NEE's regulatory assets and liabilities.

Nature of Accounting Estimates

Regulatory assets and liabilities represent probable future revenues that will be recovered from or refunded to customers through the ratemaking process. Regulatory assets and liabilities are included in rate base or otherwise earn (pay) a return on investment during the recovery period.

Assumptions and Accounting Approach

Accounting guidance allows regulators to create assets and impose liabilities that would not be recorded by non-rate regulated entities. If NEE's rate-regulated entities, primarily FPL, were no longer subject to cost-based rate regulation, the existing regulatory assets and liabilities would be written off unless regulators specify an alternative means of recovery or refund. In addition, the regulators, including the FPSC for FPL, have the authority to disallow recovery of costs that they consider excessive or imprudently incurred. Such costs may include, among others, fuel and O&M expenses, the cost of replacing power lost when fossil and nuclear units are unavailable, storm restoration costs and costs associated with the construction or acquisition of new facilities. The continued applicability of regulatory accounting is assessed at each reporting period.

## ENERGY MARKETING AND TRADING AND MARKET RISK SENSITIVITY

NEE and FPL are exposed to risks associated with adverse changes in commodity prices, interest rates and equity prices. Financial instruments and positions affecting the financial statements of NEE and FPL described below are held primarily for purposes other than trading. Market risk is measured as the potential loss in fair value resulting from hypothetical reasonably possible changes in commodity prices, interest rates or equity prices over the next year. Management has established risk management policies to monitor and manage such market risks, as well as credit risks.

## Commodity Price Risk

NEE and FPL use derivative instruments (primarily swaps, options, futures and forwards) to manage the physical and financial risks inherent in the purchase and sale of fuel and electricity. In addition, NEE, through NEER, uses derivatives to optimize the value of its power generation and gas infrastructure assets and engages in power and gas marketing and trading activities to take advantage of expected future favorable price movements. See Critical Accounting Policies and Estimates - Accounting for Derivatives and Hedging Activities and Note 4.

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During 2018 and 2019, the changes in the fair value of NEE's consolidated subsidiaries' energy contract derivative instruments were as follows:

| | Trading | Hedges on Owned Assets: Non-Qualifying | Hedges on Owned Assets: FPL Cost Recovery Clauses | Hedges on Owned Assets: Gulf Power Cost Recovery Clauses | NEE Total |
|---|---|---|---|---|---|
| | | | (millions) | | |
| Fair value of contracts outstanding at December 31, 2017 | $ 442 | $ 728 | $ — | $ — | $ 1,170 |
| Reclassification to realized at settlement of contracts | (159) | (28) | (6) | — | (193) |
| Value of contracts acquired | (3) | (2) | (15) | — | (20) |
| Net option premium purchases (issuances) | 47 | 9 | — | — | 56 |
| Impact of adoption of new revenue standard | 3 | (27) | — | — | (24) |
| Changes in fair value excluding reclassification to realized | 263 | 114 | (20) | — | 357 |
| Fair value of contracts outstanding at December 31, 2018 | 593 | 794 | (41) | — | 1,346 |
| Reclassification to realized at settlement of contracts | **(215)** | **(154)** | **30** | **7** | **(332)** |
| Value of contracts acquired | **28** | **9** | **—** | **(6)** | **31** |
| Net option premium purchases (issuances) | **43** | **5** | **—** | **—** | **48** |
| Changes in fair value excluding reclassification to realized | **202** | **555** | **1** | **(2)** | **756** |
| Fair value of contracts outstanding at December 31, 2019 | **651** | **1,209** | **(10)** | **(1)** | **1,849** |
| Net margin cash collateral paid (received) | | | | | **(75)** |
| Total mark-to-market energy contract net assets (liabilities) at December 31, 2019 | **$ 651** | **$ 1,209** | **$ (10)** | **$ (1)** | **$ 1,774** |

NEE's total mark-to-market energy contract net assets (liabilities) at December 31, 2019 shown above are included on the consolidated balance sheets as follows:

| | December 31, 2019 |
|---|---|
| | (millions) |
| Current derivative assets | **$ 742** |
| Noncurrent derivative assets | **1,608** |
| Current derivative liabilities | **(314)** |
| Noncurrent derivative liabilities | **(262)** |
| NEE's total mark-to-market energy contract net assets | **$ 1,774** |

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The sources of fair value estimates and maturity of energy contract derivative instruments at December 31, 2019 were as follows:

| | Maturity | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total |
| | (millions) | | | | | | |
| Trading: | | | | | | | |
| Quoted prices in active markets for identical assets | $ (191) | $ 1 | $ 29 | $ (2) | $ 4 | $ — | $ (159) |
| Significant other observable inputs | 17 | 8 | (32) | 1 | 4 | (65) | (67) |
| Significant unobservable inputs | 298 | 61 | 54 | 78 | 51 | 335 | 877 |
| Total | 124 | 70 | 51 | 77 | 59 | 270 | 651 |
| Owned Assets - Non-Qualifying: | | | | | | | |
| Quoted prices in active markets for identical assets | 9 | 8 | 6 | — | — | — | 23 |
| Significant other observable inputs | 185 | 113 | 97 | 72 | 39 | 200 | 706 |
| Significant unobservable inputs | 39 | 40 | 34 | 36 | 36 | 295 | 480 |
| Total | 233 | 161 | 137 | 108 | 75 | 495 | 1,209 |
| Owned Assets - FPL Cost Recovery Clauses: | | | | | | | |
| Quoted prices in active markets for identical assets | — | — | — | — | — | — | — |
| Significant other observable inputs | (2) | — | — | — | — | — | (2) |
| Significant unobservable inputs | (7) | (1) | — | — | — | — | (8) |
| Total | (9) | (1) | — | — | — | — | (10) |
| Owned Assets - Gulf Power Cost Recovery Clauses: | | | | | | | |
| Quoted prices in active markets for identical assets | — | — | — | — | — | — | — |
| Significant other observable inputs | (1) | — | — | — | — | — | (1) |
| Significant unobservable inputs | — | — | — | — | — | — | — |
| Total | (1) | — | — | — | — | — | (1) |
| Total sources of fair value | $ 347 | $ 230 | $ 188 | $ 185 | $ 134 | $ 765 | $ 1,849 |

With respect to commodities, NEE's Exposure Management Committee (EMC), which is comprised of certain members of senior management, and NEE's chief executive officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The EMC and NEE's chief executive officer receive periodic updates on market positions and related exposures, credit exposures and overall risk management activities.

NEE uses a value-at-risk (VaR) model to measure commodity price market risk in its trading and mark-to-market portfolios. The VaR is the estimated loss of market value based on a one-day holding period at a 95% confidence level using historical simulation methodology. The VaR figures are as follows:

| | Trading | | | Non-Qualifying Hedges and Hedges in FPL Cost Recovery Clauses[(a)] | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | FPL | NEER | NEE | FPL | NEER | NEE | FPL | NEER | NEE |
| | (millions) | | | | | | | | |
| December 31, 2018 | $ — | $ 5 | $ 5 | $ — | $ 45 | $ 46 | $ — | $ 46 | $ 46 |
| December 31, 2019 | **$ —** | **$ 2** | **$ 2** | **$ —** | **$ 25** | **$ 25** | **$ —** | **$ 26** | **$ 26** |
| Average for the year ended December 31, 2019 | **$ —** | **$ 3** | **$ 3** | **$ —** | **$ 34** | **$ 34** | **$ —** | **$ 34** | **$ 34** |

(a) Non-qualifying hedges are employed to reduce the market risk exposure to physical assets or contracts which are not marked to market. The VaR figures for the non-qualifying hedges and hedges in FPL cost recovery clauses category do not represent the economic exposure to commodity price movements.

## Interest Rate Risk

NEE's and FPL's financial results are exposed to risk resulting from changes in interest rates as a result of their respective outstanding and expected future issuances of debt, investments in special use funds and other investments. NEE and FPL manage their respective interest rate exposure by monitoring current interest rates, entering into interest rate contracts and using a combination of fixed rate and variable rate debt. Interest rate contracts are used to mitigate and adjust interest rate exposure when deemed appropriate based upon market conditions or when required by financing agreements.

The following are estimates of the fair value of NEE's and FPL's financial instruments that are exposed to interest rate risk:

| | December 31, 2019 | | December 31, 2018 | |
|---|---|---|---|---|
| | **Carrying Amount** | **Estimated Fair Value[a]** | Carrying Amount | Estimated Fair Value[a] |
| | (millions) | | | |
| NEE: | | | | |
| Fixed income securities: | | | | |
| Special use funds | **$ 2,099** | **$ 2,099** | $ 1,956 | $ 1,956 |
| Other investments, primarily debt securities | **$ 181** | **$ 181** | $ 180 | $ 180 |
| Long-term debt, including current portion | **$ 39,667** | **$ 42,928** | $ 29,498 | $ 30,043 |
| Interest rate contracts - net unrealized losses | **$ (716)** | **$ (716)** | $ (416) | $ (416) |
| FPL: | | | | |
| Fixed income securities - special use funds | **$ 1,574** | **$ 1,574** | $ 1,513 | $ 1,513 |
| Long-term debt, including current portion | **$ 14,161** | **$ 16,448** | $ 11,783 | $ 12,613 |

(a) See Note 5.

The special use funds of NEE and FPL consist of restricted funds set aside to cover the cost of storm damage for FPL and for the decommissioning of NEE's and FPL's nuclear power plants. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery. A portion of these funds is invested in fixed income debt securities primarily carried at estimated fair value. At FPL, changes in fair value, including any OTTI losses, result in a corresponding adjustment to the related regulatory asset or liability accounts based on current regulatory treatment. The changes in fair value of NEE's non-rate regulated operations result in a corresponding adjustment to OCI, except for impairments deemed to be other than temporary, including any credit losses, which are reported in current period earnings. Because the funds set aside by FPL for storm damage could be needed at any time, the related investments are generally more liquid and, therefore, are less sensitive to changes in interest rates. The nuclear decommissioning funds, in contrast, are generally invested in longer-term securities.

At December 31, 2019, NEE had interest rate contracts with a net notional amount of approximately $8.9 billion related to expected future and outstanding debt issuances and borrowings, of which $9.6 billion manages exposure to the variability of cash flows associated with expected future and outstanding debt issuances at NEECH and NEER. The offsetting $700 million of notional amount of interest rate contracts effectively convert fixed-rate debt to variable-rate debt instruments at NEECH. See Note 4.

Based upon a hypothetical 10% decrease in interest rates, which is a reasonable near-term market change, the fair value of NEE's net liabilities would increase by approximately $1,797 million ($611 million for FPL) at December 31, 2019.

## Equity Price Risk

NEE and FPL are exposed to risk resulting from changes in prices for equity securities. For example, NEE's nuclear decommissioning reserve funds include marketable equity securities carried at their market value of approximately $3,963 million and $3,046 million ($2,491 million and $1,850 million for FPL) at December 31, 2019 and 2018, respectively. NEE's and FPL's investment strategy for equity securities in their nuclear decommissioning reserve funds emphasizes marketable securities which are broadly diversified. At December 31, 2019, a hypothetical 10% decrease in the prices quoted on stock exchanges, which is a reasonable near-term market change, would result in a $370 million ($236 million for FPL) reduction in fair value. For FPL, a corresponding adjustment would be made to the related regulatory asset or liability accounts based on current regulatory treatment, and for NEE's non-rate regulated operations, a corresponding amount would be recorded in change in unrealized gains (losses) on equity securities held in NEER's nuclear decommissioning funds - net in NEE's consolidated statements of income.

## Credit Risk

NEE and its subsidiaries, including FPL, are also exposed to credit risk through their energy marketing and trading operations. Credit risk is the risk that a financial loss will be incurred if a counterparty to a transaction does not fulfill its financial obligation. NEE manages counterparty credit risk for its subsidiaries with energy marketing and trading operations through established policies, including counterparty credit limits, and in some cases credit enhancements, such as cash prepayments, letters of credit, cash and other collateral and guarantees.

Credit risk is also managed through the use of master netting agreements. NEE's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis. For all derivative and contractual transactions, NEE's energy marketing and trading operations, which include FPL's energy marketing and trading division, are exposed to losses in the event of nonperformance by counterparties to these transactions. Some relevant considerations when assessing NEE's energy marketing and trading operations' credit risk exposure include the following:

- Operations are primarily concentrated in the energy industry.

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- Trade receivables and other financial instruments are predominately with energy, utility and financial services related companies, as well as municipalities, cooperatives and other trading companies in the U.S.
- Overall credit risk is managed through established credit policies and is overseen by the EMC.
- Prospective and existing customers are reviewed for creditworthiness based upon established standards, with customers not meeting minimum standards providing various credit enhancements or secured payment terms, such as letters of credit or the posting of margin cash collateral.
- Master netting agreements are used to offset cash and noncash gains and losses arising from derivative instruments with the same counterparty. NEE's policy is to have master netting agreements in place with significant counterparties.

Based on NEE's policies and risk exposures related to credit, NEE and FPL do not anticipate a material adverse effect on their financial statements as a result of counterparty nonperformance. At December 31, 2019, approximately 87% of NEE's and 99% of FPL's energy marketing and trading counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

### Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Management's Discussion – Energy Marketing and Trading and Market Risk Sensitivity.

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## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NextEra Energy, Inc.'s (NEE) and Florida Power & Light Company's (FPL) management are responsible for establishing and maintaining adequate internal control over financial reporting as defined in the Securities Exchange Act of 1934 Rules 13a-15(f) and 15d-15(f). The consolidated financial statements, which in part are based on informed judgments and estimates made by management, have been prepared in conformity with generally accepted accounting principles applied on a consistent basis.

To aid in carrying out this responsibility, we, along with all other members of management, maintain a system of internal accounting control which is established after weighing the cost of such controls against the benefits derived. In the opinion of management, the overall system of internal accounting control provides reasonable assurance that the assets of NEE and FPL and their subsidiaries are safeguarded and that transactions are executed in accordance with management's authorization and are properly recorded for the preparation of financial statements. In addition, management believes the overall system of internal accounting control provides reasonable assurance that material errors or irregularities would be prevented or detected on a timely basis by employees in the normal course of their duties. Any system of internal accounting control, no matter how well designed, has inherent limitations, including the possibility that controls can be circumvented or overridden and misstatements due to error or fraud may occur and not be detected. Also, because of changes in conditions, internal control effectiveness may vary over time. Accordingly, even an effective system of internal control will provide only reasonable assurance with respect to financial statement preparation and reporting.

The system of internal accounting control is supported by written policies and guidelines, the selection and training of qualified employees, an organizational structure that provides an appropriate division of responsibility and a program of internal auditing. NEE's written policies include a Code of Business Conduct & Ethics that states management's policy on conflicts of interest and ethical conduct. Compliance with the Code of Business Conduct & Ethics is confirmed annually by key personnel.

The Board of Directors pursues its oversight responsibility for financial reporting and accounting through its Audit Committee. This Committee, which is comprised entirely of independent directors, meets regularly with management, the internal auditors and the independent auditors to make inquiries as to the manner in which the responsibilities of each are being discharged. The independent auditors and the internal audit staff have free access to the Committee without management's presence to discuss auditing, internal accounting control and financial reporting matters.

Management assessed the effectiveness of NEE's and FPL's internal control over financial reporting as of December 31, 2019, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the *Internal Control - Integrated Framework (2013)*. Based on this assessment, management believes that NEE's and FPL's internal control over financial reporting was effective as of December 31, 2019.

NEE's and FPL's independent registered public accounting firm, Deloitte & Touche LLP, is engaged to express an opinion on NEE's and FPL's consolidated financial statements and an opinion on NEE's and FPL's internal control over financial reporting. Their reports are based on procedures believed by them to provide a reasonable basis to support such opinions. These reports appear on the following pages.

**JAMES L. ROBO**

James L. Robo
Chairman, President and Chief Executive Officer of NEE and Chairman of FPL

**REBECCA J. KUJAWA**

Rebecca J. Kujawa
Executive Vice President, Finance and Chief Financial Officer of NEE and FPL

**JAMES M. MAY**

James M. May
Vice President, Controller and Chief Accounting Officer of NEE

**ERIC E. SILAGY**

Eric E. Silagy
President and Chief Executive Officer of FPL

**KEITH FERGUSON**

Keith Ferguson
Controller of FPL

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of
NextEra Energy, Inc. and Florida Power & Light Company

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of NextEra Energy, Inc. and subsidiaries (NEE) and Florida Power & Light Company and subsidiaries (FPL) as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, NEE and FPL maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019 of NEE and FPL and our report dated February 14, 2020, expressed unqualified opinions on those financial statements.

**Basis for Opinion**

NEE's and FPL's management are responsible for maintaining effective internal control over financial reporting and for their assessments of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on NEE's and FPL's internal control over financial reporting based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to NEE and FPL in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DELOITTE & TOUCHE LLP

Boca Raton, Florida
February 14, 2020

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the shareholders and the Board of Directors of
NextEra Energy, Inc. and Florida Power & Light Company

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of NextEra Energy, Inc. and subsidiaries (NEE) and the related separate consolidated balance sheets of Florida Power & Light Company and subsidiaries (FPL) as of December 31, 2019 and 2018, and NEE's and FPL's related consolidated statements of income and of cash flows, NEE's consolidated statements of comprehensive income and of equity, and FPL's consolidated statements of common shareholder's equity, for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of NEE and the consolidated financial position of FPL as of December 31, 2019 and 2018, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), NEE's and FPL's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2020, expressed unqualified opinions on NEE's and FPL's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of NEE's and FPL's management. Our responsibility is to express opinions on NEE's and FPL's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to NEE and FPL in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinions.

**Critical Audit Matter - NEE**

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements of NEE that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

***NEE - Operating Revenue - Unrealized Gains - Refer to Note 5 to the financial statements***

*Critical Audit Matter Description*

NEE enters into complex energy derivatives and transacts in certain markets that are thinly traded, which may result in subjective estimates of fair value that include unobservable inputs. Changes in the derivatives' fair value for power purchases and sales, fuel sales and trading activities are primarily recognized on a net basis in operating revenues. For the year ended December 31, 2019, unrealized gains associated with Level 3 transactions of $638 million are included in operating revenues in the consolidated statement of income of NEE.

Given management uses complex proprietary models and unobservable inputs to estimate the fair value of Level 3 derivative assets and liabilities, performing audit procedures to evaluate the appropriateness of these models and inputs required a high degree of auditor judgment and an increased extent of effort, including the need to involve our firm specialists who possess significant quantitative and modeling expertise.

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*How the Critical Audit Matter Was Addressed in the Audit*

Our audit procedures related to operating revenue - unrealized gains included the following, among others:

- We tested the effectiveness of controls, including those relating to commodity valuation models, and market data validation.
- We selected a sample of transactions, obtained an understanding of the business rationale of transactions and read the underlying contractual agreements.
- We used personnel in our firm who specialize in energy transacting to assist in auditing NEE's energy transactions, including testing certain inputs in managements fair value models.
- We used personnel in our firm who specialize in the valuation of energy products to independently value Level 3 transactions to provide us with a benchmark for comparison to NEE valuations.

DELOITTE & TOUCHE LLP

Boca Raton, Florida
February 14, 2020

We have served as NEE's and FPL's auditor since 1950.

**NEXTERA ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF INCOME**
**(millions, except per share amounts)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| OPERATING REVENUES | **$ 19,204** | $ 16,727 | $ 17,173 |
| OPERATING EXPENSES (INCOME) | | | |
| Fuel, purchased power and interchange | **4,363** | 3,732 | 4,071 |
| Other operations and maintenance | **3,640** | 3,330 | 3,458 |
| Storm restoration costs | **234** | 3 | 1,255 |
| Impairment charges | **72** | 11 | 446 |
| Acquisition-related | **35** | 32 | 69 |
| Depreciation and amortization | **4,216** | 3,911 | 2,357 |
| Gains on disposal of businesses/assets - net | **(406)** | (80) | (1,111) |
| Taxes other than income taxes and other - net | **1,697** | 1,508 | 1,455 |
| Total operating expenses - net | **13,851** | 12,447 | 12,000 |
| OPERATING INCOME | **5,353** | 4,280 | 5,173 |
| OTHER INCOME (DEDUCTIONS) | | | |
| Interest expense | **(2,249)** | (1,498) | (1,558) |
| Benefits associated with differential membership interests - net | **—** | — | 460 |
| Equity in earnings of equity method investees | **66** | 358 | 141 |
| Allowance for equity funds used during construction | **67** | 96 | 92 |
| Interest income | **54** | 51 | 81 |
| Gain on NEP deconsolidation | **—** | 3,927 | — |
| Gains on disposal of investments and other property - net | **55** | 111 | 112 |
| Change in unrealized gains (losses) on equity securities held in NEER's nuclear decommissioning funds - net | **238** | (189) | — |
| Other net periodic benefit income | **185** | 168 | 151 |
| Other - net | **67** | 48 | 11 |
| Total other income (deductions) - net | **(1,517)** | 3,072 | (510) |
| INCOME BEFORE INCOME TAXES | **3,836** | 7,352 | 4,663 |
| INCOME TAX EXPENSE (BENEFIT) | **448** | 1,576 | (660) |
| NET INCOME | **3,388** | 5,776 | 5,323 |
| NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS | **381** | 862 | 57 |
| NET INCOME ATTRIBUTABLE TO NEE | **$ 3,769** | $ 6,638 | $ 5,380 |
| Earnings per share attributable to NEE: | | | |
| Basic | **$ 7.82** | $ 14.03 | $ 11.48 |
| Assuming dilution | **$ 7.76** | $ 13.88 | $ 11.39 |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**NEXTERA ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(millions)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| NET INCOME | **$ 3,388** | $ 5,776 | $ 5,323 |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX | | | |
| Reclassification of unrealized losses on cash flow hedges from accumulated other comprehensive income (loss) to net income (net of $8, $8 and $13 tax expense, respectively) | **29** | 26 | 32 |
| Net unrealized gains (losses) on available for sale securities: | | | |
| Net unrealized gains (losses) on securities still held (net of $8 tax expense, $5 tax benefit and $94 tax expense, respectively) | **20** | (12) | 127 |
| Reclassification from accumulated other comprehensive income (loss) to net income (net of $1, less than $1 and $25 tax benefit, respectively) | **(2)** | 1 | (36) |
| Defined benefit pension and other benefits plans: | | | |
| Net unrealized gain (loss) and unrecognized prior service benefit (cost) (net of $14 and $5 tax benefit and $29 tax expense, respectively) | **(46)** | (14) | 46 |
| Reclassification from accumulated other comprehensive income (loss) to net income (net of $1, $1 and $1 tax benefit, respectively) | **(3)** | (3) | (2) |
| Net unrealized gains (losses) on foreign currency translation (net of $0, $0 and $1 tax expense, respectively) | **22** | (31) | 23 |
| Other comprehensive income related to equity method investees (net of $0, $1 and $1 tax expense, respectively) | **1** | 4 | 2 |
| Total other comprehensive income (loss), net of tax | **21** | (29) | 192 |
| IMPACT OF NEP DECONSOLIDATION (NET OF $15 TAX EXPENSE) | **—** | 58 | — |
| COMPREHENSIVE INCOME | **3,409** | 5,805 | 5,515 |
| COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS | **380** | 862 | 46 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO NEE | **$ 3,789** | $ 6,667 | $ 5,561 |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**NEXTERA ENERGY, INC.**
**CONSOLIDATED BALANCE SHEETS**
**(millions, except par value)**

| | December 31, 2019 | 2018 |
|---|---|---|
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric plant in service and other property | **$ 96,093** | $ 81,986 |
| Nuclear fuel | **1,755** | 1,740 |
| Construction work in progress | **9,330** | 8,357 |
| Accumulated depreciation and amortization | **(25,168)** | (21,749) |
| Total property, plant and equipment - net ($11,893 and $10,553 related to VIEs, respectively) | **82,010** | 70,334 |
| CURRENT ASSETS | | |
| Cash and cash equivalents | **600** | 638 |
| Customer receivables, net of allowances of $19 and $10, respectively | **2,282** | 2,302 |
| Other receivables | **525** | 667 |
| Materials, supplies and fossil fuel inventory | **1,328** | 1,223 |
| Regulatory assets ($41 related to a VIE at December 31, 2018) | **335** | 448 |
| Derivatives | **762** | 564 |
| Other | **1,576** | 551 |
| Total current assets | **7,408** | 6,393 |
| OTHER ASSETS | | |
| Special use funds | **6,954** | 5,886 |
| Investment in equity method investees | **7,453** | 6,748 |
| Prepaid benefit costs | **1,437** | 1,284 |
| Regulatory assets | **3,287** | 3,290 |
| Derivatives | **1,624** | 1,355 |
| Goodwill | **4,204** | 891 |
| Other | **3,314** | 7,521 |
| Total other assets | **28,273** | 26,975 |
| TOTAL ASSETS | **$ 117,691** | $ 103,702 |
| CAPITALIZATION | | |
| Common stock ($0.01 par value, authorized shares - 800; outstanding shares - 489 and 478, respectively) | **$ 5** | $ 5 |
| Additional paid-in capital | **11,970** | 10,490 |
| Retained earnings | **25,199** | 23,837 |
| Accumulated other comprehensive loss | **(169)** | (188) |
| Total common shareholders' equity | **37,005** | 34,144 |
| Noncontrolling interests ($4,350 and $3,265 related to VIEs, respectively) | **4,355** | 3,269 |
| Total equity | **41,360** | 37,413 |
| Redeemable noncontrolling interests | **487** | 468 |
| Long-term debt ($498 and $1,020 related to VIEs, respectively) | **37,543** | 26,782 |
| Total capitalization | **79,390** | 64,663 |
| CURRENT LIABILITIES | | |
| Commercial paper | **2,516** | 2,749 |
| Other short-term debt | **400** | 5,465 |
| Current portion of long-term debt ($27 and $74 related to VIEs, respectively) | **2,124** | 2,716 |
| Accounts payable | **3,631** | 2,386 |
| Customer deposits | **499** | 445 |
| Accrued interest and taxes | **558** | 477 |
| Derivatives | **344** | 675 |
| Accrued construction-related expenditures | **1,152** | 1,195 |
| Regulatory liabilities | **320** | 325 |
| Other | **2,309** | 1,130 |
| Total current liabilities | **13,853** | 17,563 |
| OTHER LIABILITIES AND DEFERRED CREDITS | | |
| Asset retirement obligations | **3,457** | 3,135 |
| Deferred income taxes | **8,361** | 7,367 |
| Regulatory liabilities | **9,936** | 9,009 |
| Derivatives | **863** | 516 |
| Other | **1,831** | 1,449 |
| Total other liabilities and deferred credits | **24,448** | 21,476 |
| COMMITMENTS AND CONTINGENCIES | | |
| TOTAL CAPITALIZATION AND LIABILITIES | **$ 117,691** | $ 103,702 |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**NEXTERA ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(millions)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | **$ 3,388** | $ 5,776 | $ 5,323 |
| Adjustments to reconcile net income to net cash provided by (used in) operating activities: | | | |
| Depreciation and amortization | **4,216** | 3,911 | 2,357 |
| Nuclear fuel and other amortization | **262** | 236 | 281 |
| Impairment charges | **72** | 11 | 446 |
| Unrealized losses (gains) on marked to market derivative contracts – net | **(108)** | 54 | 436 |
| Foreign currency transaction losses (gains) | **17** | 16 | (25) |
| Deferred income taxes | **258** | 1,463 | (882) |
| Cost recovery clauses and franchise fees | **155** | (225) | 82 |
| Acquisition of purchased power agreement | **—** | (52) | (243) |
| Benefits associated with differential membership interests - net | **—** | — | (460) |
| Equity in earnings of equity method investees | **(66)** | (358) | (141) |
| Distributions of earnings from equity method investees | **438** | 328 | 160 |
| Gains on disposal of businesses, assets and investments – net | **(461)** | (191) | (1,223) |
| Gain on NEP deconsolidation | **—** | (3,927) | — |
| Recoverable storm-related costs | **(180)** | — | (108) |
| Other - net | **(213)** | 156 | 109 |
| Changes in operating assets and liabilities: | | | |
| Current assets | **123** | (631) | (333) |
| Noncurrent assets | **(93)** | (220) | (60) |
| Current liabilities | **116** | 163 | 758 |
| Noncurrent liabilities | **231** | 83 | (19) |
| Net cash provided by operating activities | **8,155** | 6,593 | 6,458 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures of FPL | **(5,560)** | (5,012) | (5,174) |
| Acquisition and capital expenditures of Gulf Power | **(5,165)** | — | — |
| Independent power and other investments of NEER | **(6,385)** | (7,045) | (5,335) |
| Nuclear fuel purchases | **(315)** | (267) | (197) |
| Other capital expenditures, acquisitions and other investments | **(37)** | (680) | (34) |
| Proceeds from sale of the fiber-optic telecommunications business | **—** | — | 1,454 |
| Sale of independent power and other investments of NEER | **1,163** | 1,617 | 178 |
| Proceeds from sale or maturity of securities in special use funds and other investments | **4,008** | 3,410 | 3,207 |
| Purchases of securities in special use funds and other investments | **(4,160)** | (3,733) | (3,244) |
| Distributions from equity method investees | **—** | 637 | 7 |
| Other - net | **274** | 123 | 220 |
| Net cash used in investing activities | **(16,177)** | (10,950) | (8,918) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Issuances of long-term debt | **13,919** | 4,399 | 8,354 |
| Retirements of long-term debt | **(5,492)** | (3,102) | (6,780) |
| Proceeds from differential membership investors | **1,604** | 1,841 | 1,414 |
| Net change in commercial paper | **(234)** | 1,062 | 1,419 |
| Proceeds from other short-term debt | **200** | 5,665 | 450 |
| Repayments of other short-term debt | **(4,765)** | (455) | (2) |
| Payments to related parties under a cash sweep and credit support agreement – net | **(54)** | (21) | — |
| Issuances of common stock - net | **1,494** | 718 | 55 |
| Proceeds from issuance of NEP convertible preferred units - net | **—** | — | 548 |
| Dividends on common stock | **(2,408)** | (2,101) | (1,845) |
| Other - net | **(391)** | (372) | (725) |
| Net cash provided by financing activities | **3,873** | 7,634 | 2,888 |
| Effects of currency translation on cash, cash equivalents and restricted cash | **4** | (7) | 26 |
| Net increase (decrease) in cash, cash equivalents and restricted cash | **(4,145)** | 3,270 | 454 |
| Cash, cash equivalents and restricted cash at beginning of year | **5,253** | 1,983 | 1,529 |
| Cash, cash equivalents and restricted cash at end of year | **$ 1,108** | $ 5,253 | $ 1,983 |
| SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION | | | |
| Cash paid for interest (net of amount capitalized) | **$ 1,799** | $ 1,209 | $ 1,186 |
| Cash paid for income taxes - net | **$ 184** | $ 200 | $ 142 |
| SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES | | | |
| Accrued property additions | **$ 3,573** | $ 2,138 | $ 3,029 |
| Increase in property, plant and equipment - net as a result of cash grants primarily under the American Recovery and Reinvestment Act of 2009 | **$ —** | $ — | $ (154) |
| Increase in property, plant and equipment - net as a result of a settlement/noncash exchange | **$ (7)** | $ (5) | $ (108) |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**NEXTERA ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(millions)**

| | Common Stock | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Shares | Aggregate Par Value | Additional Paid-In Capital | Accumulated Other Comprehensive Income (Loss) | Retained Earnings | Total Common Shareholders' Equity | Non-controlling Interests | Total Equity |
| Balances, December 31, 2016 | 468 | $ 5 | $ 8,948 | $ (70) | $ 15,484 | $ 24,367 | $ 991 | $ 25,358 |
| Net income (loss) | — | — | — | — | 5,380 | 5,380 | (57) | |
| Issuances of common stock - net | 2 | — | 33 | — | — | 33 | — | |
| Share-based payment activity | 1 | — | 122 | — | — | 122 | — | |
| Dividends on common stock[a] | — | — | — | — | (1,845) | (1,845) | — | |
| Other comprehensive income | — | — | — | 181 | — | 181 | 11 | |
| Sale of NEER assets to NEP | — | — | — | — | — | — | 460 | |
| Other | — | — | (3) | — | 1 | (2) | (110) | |
| Balances, December 31, 2017 | 471 | 5 | 9,100 | 111 | 19,020 | 28,236 | 1,295 | $ 29,531 |
| Net income (loss) | — | — | — | — | 6,638 | 6,638 | (862) | |
| Issuances of common stock - net | 6 | — | 700 | — | — | 700 | — | |
| Share-based payment activity | 1 | — | 121 | — | — | 121 | — | |
| Dividends on common stock[a] | — | — | — | — | (2,101) | (2,101) | — | |
| Other comprehensive loss | — | — | — | (29) | — | (29) | — | |
| Impact of NEP deconsolidation[b] | — | — | — | 58 | — | 58 | (2,700) | |
| Sales of differential membership interests to NEP | — | — | — | — | — | — | (941) | |
| Adoption of accounting standards updates | — | — | 590 | (328) | 280 | 542 | 5,303 | |
| Other differential membership interests activity | — | — | (21) | — | — | (21) | 1,243 | |
| Other | — | — | — | — | — | — | (69) | |
| Balances, December 31, 2018 | 478 | 5 | 10,490 | (188) | 23,837 | 34,144 | 3,269 | $ 37,413 |
| Net income (loss) | **—** | **—** | **—** | **—** | **3,769** | **3,769** | **(371)** | |
| Issuances of common stock - net | **10** | **—** | **1,470** | **—** | **—** | **1,470** | **—** | |
| Share-based payment activity | **1** | **—** | **164** | **—** | **—** | **164** | **—** | |
| Dividends on common stock[a] | **—** | **—** | **—** | **—** | **(2,408)** | **(2,408)** | **—** | |
| Other comprehensive income | **—** | **—** | **—** | **20** | **—** | **20** | **1** | |
| Premium on equity units | **—** | **—** | **(120)** | **—** | **—** | **(120)** | | |
| Other differential membership interests activity | **—** | **—** | **(20)** | **—** | **—** | **(20)** | **1,270** | |
| Other | **—** | **—** | **(14)** | **(1)** | **1** | **(14)** | **186** | |
| Balances, December 31, 2019 | **489** | **$ 5** | **$ 11,970** | **$ (169)** | **$ 25,199** | **$ 37,005** | **$ 4,355** | **$ 41,360** |

(a) Dividends per share were $5.00, $4.44 and $3.93 for the years ended December 31, 2019, 2018 and 2017, respectively.
(b) See Note 1 - NextEra Energy Partners, LP.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**FLORIDA POWER & LIGHT COMPANY**
**CONSOLIDATED STATEMENTS OF INCOME**
**(millions)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| OPERATING REVENUES | **$ 12,192** | $ 11,862 | $ 11,972 |
| OPERATING EXPENSES (INCOME) | | | |
| Fuel, purchased power and interchange | **3,256** | 3,250 | 3,541 |
| Other operations and maintenance | **1,519** | 1,514 | 1,554 |
| Storm restoration costs | **234** | 3 | 1,255 |
| Depreciation and amortization | **2,524** | 2,633 | 940 |
| Taxes other than income taxes and other - net | **1,357** | 1,308 | 1,292 |
| Total operating expenses - net | **8,890** | 8,708 | 8,582 |
| OPERATING INCOME | **3,302** | 3,154 | 3,390 |
| OTHER INCOME (DEDUCTIONS) | | | |
| Interest expense | **(594)** | (541) | (481) |
| Allowance for equity funds used during construction | **62** | 90 | 79 |
| Other - net | **5** | 7 | (2) |
| Total other deductions - net | **(527)** | (444) | (404) |
| INCOME BEFORE INCOME TAXES | **2,775** | 2,710 | 2,986 |
| INCOME TAXES | **441** | 539 | 1,106 |
| NET INCOME[(a)] | **$ 2,334** | $ 2,171 | $ 1,880 |

(a) FPL's comprehensive income is the same as reported net income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**FLORIDA POWER & LIGHT COMPANY**
**CONSOLIDATED BALANCE SHEETS**
**(millions, except share amount)**

| | December 31, | |
|---|---|---|
| | **2019** | 2018 |
| ELECTRIC UTILITY PLANT AND OTHER PROPERTY | | |
| Plant in service and other property | **$ 54,523** | $ 49,640 |
| Nuclear fuel | **1,153** | 1,189 |
| Construction work in progress | **3,351** | 3,888 |
| Accumulated depreciation and amortization | **(13,953)** | (13,218) |
| Total electric utility plant and other property - net | **45,074** | 41,499 |
| CURRENT ASSETS | | |
| Cash and cash equivalents | **77** | 112 |
| Customer receivables, net of allowances of $3 and $3, respectively | **1,024** | 1,026 |
| Other receivables | **333** | 284 |
| Materials, supplies and fossil fuel inventory | **722** | 670 |
| Regulatory assets ($41 related to a VIE at December 31, 2018) | **227** | 447 |
| Other | **136** | 239 |
| Total current assets | **2,519** | 2,778 |
| OTHER ASSETS | | |
| Special use funds | **4,771** | 4,056 |
| Prepaid benefit costs | **1,477** | 1,407 |
| Regulatory assets | **2,549** | 2,843 |
| Goodwill | **300** | 302 |
| Other | **498** | 599 |
| Total other assets | **9,595** | 9,207 |
| TOTAL ASSETS | **$ 57,188** | $ 53,484 |
| CAPITALIZATION | | |
| Common stock (no par value, 1,000 shares authorized, issued and outstanding) | **$ 1,373** | $ 1,373 |
| Additional paid-in capital | **10,851** | 10,601 |
| Retained earnings | **9,174** | 9,040 |
| Total common shareholder's equity | **21,398** | 21,014 |
| Long-term debt | **14,131** | 11,688 |
| Total capitalization | **35,529** | 32,702 |
| CURRENT LIABILITIES | | |
| Commercial paper | **1,482** | 1,256 |
| Current portion of long-term debt ($74 related to a VIE at December 31, 2018) | **30** | 95 |
| Accounts payable | **768** | 731 |
| Customer deposits | **459** | 442 |
| Accrued interest and taxes | **266** | 376 |
| Accrued construction-related expenditures | **426** | 323 |
| Regulatory liabilities | **284** | 310 |
| Other | **510** | 543 |
| Total current liabilities | **4,225** | 4,076 |
| OTHER LIABILITIES AND DEFERRED CREDITS | | |
| Asset retirement obligations | **2,268** | 2,147 |
| Deferred income taxes | **5,415** | 5,165 |
| Regulatory liabilities | **9,296** | 8,886 |
| Other | **455** | 508 |
| Total other liabilities and deferred credits | **17,434** | 16,706 |
| COMMITMENTS AND CONTINGENCIES | | |
| TOTAL CAPITALIZATION AND LIABILITIES | **$ 57,188** | $ 53,484 |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**FLORIDA POWER & LIGHT COMPANY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(millions)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | **$ 2,334** | $ 2,171 | $ 1,880 |
| Adjustments to reconcile net income to net cash provided by (used in) operating activities: | | | |
| Depreciation and amortization | **2,524** | 2,633 | 940 |
| Nuclear fuel and other amortization | **175** | 144 | 159 |
| Deferred income taxes | **44** | 180 | 905 |
| Cost recovery clauses and franchise fees | **177** | (225) | 82 |
| Acquisition of purchased power agreement | **—** | (52) | (243) |
| Recoverable storm-related costs | **—** | — | (108) |
| Other - net | **6** | 7 | (139) |
| Changes in operating assets and liabilities: | | | |
| Current assets | **(48)** | 97 | (190) |
| Noncurrent assets | **(67)** | (64) | (37) |
| Current liabilities | **32** | (509) | 699 |
| Noncurrent liabilities | **4** | 40 | (32) |
| Net cash provided by operating activities | **5,181** | 4,422 | 3,916 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures | **(5,560)** | (5,012) | (5,174) |
| Nuclear fuel purchases | **(195)** | (123) | (117) |
| Proceeds from sale or maturity of securities in special use funds | **2,729** | 2,232 | 1,986 |
| Purchases of securities in special use funds | **(2,854)** | (2,402) | (2,082) |
| Other - net | **10** | 239 | 18 |
| Net cash used in investing activities | **(5,870)** | (5,066) | (5,369) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Issuances of long-term debt | **2,498** | 1,748 | 1,961 |
| Retirements of long-term debt | **(95)** | (1,591) | (882) |
| Net change in commercial paper | **226** | (431) | 1,419 |
| Proceeds from other short-term debt | **—** | — | 450 |
| Repayments of other short-term debt | **—** | (250) | (2) |
| Capital contributions from NEE | **250** | 1,785 | — |
| Dividends to NEE | **(2,200)** | (500) | (1,450) |
| Other - net | **(49)** | (37) | (22) |
| Net cash provided by financing activities | **630** | 724 | 1,474 |
| Net increase (decrease) in cash, cash equivalents and restricted cash | **(59)** | 80 | 21 |
| Cash, cash equivalents and restricted cash at beginning of year | **254** | 174 | 153 |
| Cash, cash equivalents and restricted cash at end of year | **$ 195** | $ 254 | $ 174 |
| SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION | | | |
| Cash paid for interest (net of amount capitalized) | **$ 561** | $ 520 | $ 473 |
| Cash paid for income taxes - net | **$ 544** | $ 415 | $ 2 |
| SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES | | | |
| Accrued property additions | **$ 680** | $ 549 | $ 668 |
| Increase in electric utility plant and other property - net as a result of a noncash exchange | **$ (7)** | $ (5) | $ (112) |
| NEE's noncash contribution of a consolidated subsidiary - net | **$ —** | $ 526 | $ — |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**FLORIDA POWER & LIGHT COMPANY**
**CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY**
**(millions)**

| | Common Stock | Additional Paid-In Capital | Retained Earnings | Common Shareholder's Equity |
|---|---|---|---|---|
| Balances, December 31, 2016 | $ 1,373 | $ 8,332 | $ 6,875 | $ 16,580 |
| Net income | — | — | 1,880 | |
| Dividends to NEE | — | — | (1,450) | |
| Other | — | (41) | 71 | |
| Balances, December 31, 2017 | 1,373 | 8,291 | 7,376 | $ 17,040 |
| Net income | — | — | 2,171 | |
| Capital contributions from NEE | — | 1,785 | — | |
| Dividends to NEE | — | — | (500) | |
| NEE's contribution of a consolidated subsidiary | — | 526 | — | |
| Other | — | (1) | (7) | |
| Balances, December 31, 2018 | 1,373 | 10,601 | 9,040 | $ 21,014 |
| Net income | **—** | **—** | **2,334** | |
| Capital contributions from NEE | **—** | **250** | **—** | |
| Dividends to NEE | **—** | **—** | **(2,200)** | |
| Balances, December 31, 2019 | **$ 1,373** | **$ 10,851** | **$ 9,174** | **$ 21,398** |

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

**NEXTERA ENERGY, INC. AND FLORIDA POWER & LIGHT COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**Years Ended December 31, 2019, 2018 and 2017**

## 1. Summary of Significant Accounting and Reporting Policies

*Basis of Presentation* - The operations of NextEra Energy, Inc. (NEE) are conducted primarily through Florida Power & Light Company (FPL), a wholly owned subsidiary, and NextEra Energy Resources, LLC (NextEra Energy Resources) and NextEra Energy Transmission, LLC (NEET) (collectively, NEER), wholly owned indirect subsidiaries that are combined for segment reporting purposes. FPL's principal business is a rate-regulated electric utility which supplies electric service to more than five million customer accounts throughout most of the east and lower west coasts of Florida. NEER invests in independent power projects through both controlled and consolidated entities and noncontrolling ownership interests in joint ventures. NEER participates in natural gas, natural gas liquids and oil production primarily through operating and non-operating ownership interests and in pipeline infrastructure through either wholly owned subsidiaries or noncontrolling or joint venture interests. NEER also invests in rate-regulated transmission facilities and transmission lines that connect its electric generation facilities to the electric grid through controlled and consolidated entities. See Note 16 for a discussion of the movement of NEET to the NEER segment from Corporate and Other.

The consolidated financial statements of NEE and FPL include the accounts of their respective controlled subsidiaries. They also include NEE's and FPL's share of the undivided interest in certain assets, liabilities, revenues and expenses. Amounts representing NEE's interest in entities it does not control, but over which it exercises significant influence, are included in investment in equity method investees; the net income of these entities is included in equity in earnings of equity method investees. Intercompany balances and transactions have been eliminated in consolidation. Certain amounts included in prior years' consolidated financial statements have been reclassified to conform to the current year's presentation. The preparation of financial statements requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

*NextEra Energy Partners, LP* - NEP was formed in 2014 to acquire, manage and own contracted clean energy projects with stable long-term cash flows through a limited partner interest in NextEra Energy Operating Partners, LP (NEP OpCo). NEP owns or has an interest in a portfolio of wind and solar projects and long-term contracted natural gas pipelines. NEP was deconsolidated from NEE for financial reporting purposes in January 2018 as a result of changes made to NEP's governance structure during 2017 that, among other things, enhanced NEP common unitholder governance rights. The new governance structure established a NEP board of directors whereby NEP unitholders have the ability to nominate and elect board members, subject to certain limitations and requirements, which elected board members commenced service in January 2018. Subsequent to deconsolidation, NEE owns a noncontrolling interest in NEP and began reflecting its ownership interest in NEP as an equity method investment with its earnings/losses from NEP as equity in earnings (losses) of equity method investees and accounting for NextEra Energy Resources' asset sales to NEP as third-party sales in its consolidated financial statements. NEER continues to operate the projects owned by NEP and provide services to NEP under various related party operations and maintenance, administrative and management services agreements.

In connection with the deconsolidation, NEE recorded an initial investment in NEP of approximately $4.4 billion based on the fair value of NEP OpCo and NEP common units that were held by subsidiaries of NEE on the deconsolidation date, which investment is included in the investment in equity method investees on NEE's consolidated balance sheets. See Note 10. The fair value was based on the market price of NEP common units as of January 1, 2018, which resulted in NEE recording a gain of approximately $3.9 billion ($3.0 billion after tax) for the year ended December 31, 2018.

Prior to the deconsolidation, NEE owned a controlling general partner interest in NEP and consolidated NEP for financial reporting purposes. NEE presented its limited partner interests in NEP as a noncontrolling interest in NEE's consolidated financial statements. NEE’s partnership interest in NEP OpCo's operating projects based on the number of outstanding NEP OpCo common units was approximately 65.1% at December 31, 2017. Certain equity and asset transactions between NEP, NEER and NEP OpCo involve the exchange of cash, energy projects and ownership interests in NEP OpCo.

*Operating Revenues* - FPL and NEER generate substantially all of NEE’s operating revenues, which primarily include revenues from contracts with customers as further discussed in Note 2, as well as, at NEER, derivative and lease transactions. FPL's operating revenues include amounts resulting from base rates, cost recovery clauses (see Rate Regulation below), franchise fees, gross receipts taxes and surcharges related to storms (see Storm Fund, Storm Reserve and Storm Cost Recovery below). Franchise fees and gross receipts taxes are imposed on FPL; however, the Florida Public Service Commission (FPSC) allows FPL to include in the amounts charged to customers the amount of the gross receipts tax for all customers and the franchise fee for those customers located in the jurisdiction that imposes the amount. Accordingly, franchise fees and gross receipts taxes are reported gross in operating revenues and taxes other than income taxes and other in NEE's and FPL's consolidated statements of income and were approximately $763 million, $738 million and $767 million in 2019, 2018 and 2017, respectively. FPL also collects municipal utility taxes which are reported gross in customer receivables and accounts payable on NEE's and FPL's consolidated balance sheets. Certain NEER commodity contracts for the purchase and sale of power that meet the definition of a derivative are recorded at fair value with subsequent changes in fair value recognized as revenue. See Energy Trading below and Note 4.

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*Rate Regulation* - FPL, the most significant of NEE's rate-regulated subsidiaries, is subject to rate regulation by the FPSC and the Federal Energy Regulatory Commission (FERC). Its rates are designed to recover the cost of providing service to its customers including a reasonable rate of return on invested capital. As a result of this cost-based regulation, FPL follows the accounting guidance that allows regulators to create assets and impose liabilities that would not be recorded by non-rate regulated entities. Regulatory assets and liabilities represent probable future revenues that will be recovered from or refunded to customers through the ratemaking process.

NEE's and FPL's regulatory assets and liabilities are as follows:

| | NEE | | FPL | |
|---|---|---|---|---|
| | December 31, | | December 31, | |
| | **2019** | 2018 | **2019** | 2018 |
| | (millions) | | | |
| Regulatory assets: | | | | |
| Current: | | | | |
| Acquisition of purchased power agreements | **$ 165** | $ 165 | **$ 165** | $ 165 |
| Deferred clause and franchise expenses | **5** | 146 | **5** | 146 |
| Other | **165** | 137 | **57** | 136 |
| Total | **$ 335** | $ 448 | **$ 227** | $ 447 |
| Noncurrent: | | | | |
| Acquisition of purchased power agreements | **$ 634** | $ 798 | **$ 634** | $ 798 |
| Other | **2,653** | 2,492 | **1,915** | 2,045 |
| Total | **$ 3,287** | $ 3,290 | **$ 2,549** | $ 2,843 |
| Regulatory liabilities: | | | | |
| Current: | | | | |
| Deferred clause revenues | **$ 309** | $ 265 | **$ 284** | $ 265 |
| Other | **11** | 60 | **—** | 45 |
| Total | **$ 320** | $ 325 | **$ 284** | $ 310 |
| Noncurrent: | | | | |
| Asset retirement obligation regulatory expense difference | **$ 2,826** | $ 2,352 | **$ 2,828** | $ 2,352 |
| Accrued asset removal costs | **1,346** | 991 | **1,157** | 972 |
| Deferred taxes | **4,862** | 4,815 | **4,397** | 4,736 |
| Other | **902** | 851 | **914** | 826 |
| Total | **$ 9,936** | $ 9,009 | **$ 9,296** | $ 8,886 |

Cost recovery clauses, which are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through various clauses, include substantially all fuel, purchased power and interchange expense, certain costs associated with the acquisition of several electric generation facilities, certain construction-related costs for certain of FPL's solar generation facilities, and conservation and certain environmental-related costs. Revenues from cost recovery clauses are recorded when billed; FPL achieves matching of costs and related revenues by deferring the net underrecovery or overrecovery. Any underrecovered costs or overrecovered revenues are collected from or returned to customers in subsequent periods.

At December 31, 2019 and 2018, FPL had regulatory assets, net of amortization, of approximately $799 million and $963 million, respectively, (included in current and noncurrent regulatory assets on NEE's and FPL's consolidated balance sheets) related to acquisitions during 2015, 2017 and 2018 associated with three coal-fired electric generation facilities located in Florida with which FPL had long-term purchased power agreements. The majority of these regulatory assets are being amortized over approximately nine years. Two of the three facilities have been retired and FPL has reduced the third facility's operations with the intention of phasing the facility out of service.

In 2018, FPL early retired three of its generation facilities. As a result of the retirements, FPL reclassified the net book value of these units (approximately $875 million) from plant in service and other property to current and noncurrent regulatory assets. Recovery of $729 million of these regulatory assets has been deferred until FPL's base rates are next reset in a general base rate proceeding. The remainder of these regulatory assets are being amortized over 15 years. At December 31, 2019 and 2018, the regulatory assets, net of amortization, totaled approximately $851 million and $870 million, respectively, and are included in current and noncurrent regulatory assets on NEE's and FPL's consolidated balance sheets. Additionally, other regulatory assets and liabilities are discussed within various subsections in Note 1 below.

If FPL were no longer subject to cost-based rate regulation, the existing regulatory assets and liabilities would be written off unless regulators specify an alternative means of recovery or refund. In addition, the FPSC has the authority to disallow recovery of costs

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that it considers excessive or imprudently incurred. The continued applicability of regulatory accounting is assessed at each reporting period.

FPL Base Rates Effective January 2017 through at least December 2020 - In December 2016, the FPSC issued a final order approving a stipulation and settlement between FPL and several intervenors in FPL's base rate proceeding (2016 rate agreement). Key elements of the 2016 rate agreement, which is effective from January 2017 through at least December 2020, include, among other things, the following:

- New retail base rates and charges were established resulting in the following increases in annualized retail base revenues:
  - $400 million beginning January 1, 2017;
  - $211 million beginning January 1, 2018; and
  - $200 million beginning April 1, 2019 for a new approximately 1,720 megawatts (MW) natural gas-fired combined-cycle unit in Okeechobee County, Florida that achieved commercial operation on March 31, 2019.
- In addition, FPL is eligible to receive base rate increases associated with the addition of up to 300 MW annually of new solar generation in each of 2017 through 2020 with an installed cost cap of $1,750 per kilowatt (kW). Approximately 900 MW of new solar generating capacity has become operational, 600 MW in the first quarter of 2018 and 300 MW in the first quarter of 2019. An additional 300 MW is expected to be operational in the second quarter of 2020.
- FPL's allowed regulatory return on common equity (ROE) is 10.55%, with a range of 9.60% to 11.60%. If FPL's earned regulatory ROE falls below 9.60%, FPL may seek retail base rate relief. If the earned regulatory ROE rises above 11.60%, any party other than FPL may seek a review of FPL's retail base rates.
- Subject to certain conditions, FPL may amortize, over the term of the 2016 rate agreement, up to $1.0 billion of depreciation reserve surplus plus the reserve amount that remained under FPL's previous rate agreement (approximately $250 million), provided that in any year of the 2016 rate agreement FPL must amortize at least enough reserve to maintain a 9.60% earned regulatory ROE but may not amortize any reserve that would result in an earned regulatory ROE in excess of 11.60%.
- Future storm restoration costs would be recoverable on an interim basis beginning 60 days from the filing of a cost recovery petition, but capped at an amount that could produce a surcharge of no more than $4 for every 1,000 kilowatt-hour (kWh) of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover amounts above $400 million. See Storm Fund, Storm Reserve and Storm Cost Recovery below.

*Electric Plant, Depreciation and Amortization* - The cost of additions to units of property of FPL and NEER is added to electric plant in service and other property. In accordance with regulatory accounting, the cost of FPL's units of utility property retired, less estimated net salvage value, is charged to accumulated depreciation. Maintenance and repairs of property as well as replacements and renewals of items determined to be less than units of utility property are charged to other operations and maintenance (O&M) expenses. At December 31, 2019, the electric generation, transmission, distribution and general facilities of FPL represented approximately 46%, 12%, 35% and 7%, respectively, of FPL's gross investment in electric utility plant in service and other property. Substantially all of FPL's properties are subject to the lien of FPL's mortgage, which secures most debt securities issued by FPL. A number of NEER's generation, regulated transmission and pipeline facilities are encumbered by liens securing various financings. The net book value of NEER's assets serving as collateral was approximately $10.0 billion at December 31, 2019. The American Recovery and Reinvestment Act of 2009, as amended (Recovery Act), provided for an option to elect a cash grant (convertible investment tax credits (ITCs)) for certain renewable energy property (renewable property). Convertible ITCs are recorded as a reduction in property, plant and equipment on NEE's and FPL's consolidated balance sheets and are amortized as a reduction to depreciation and amortization expense over the estimated life of the related property. At December 31, 2019 and 2018, convertible ITCs, net of amortization, were approximately $824 million ($128 million at FPL) and $1.2 billion ($134 million at FPL). At December 31, 2019 and 2018, approximately $10 million and $138 million, respectively, of such convertible ITCs are included primarily in other receivables on NEE's consolidated balance sheets.

Depreciation of FPL's electric property is primarily provided on a straight-line average remaining life basis. FPL includes in depreciation expense a provision for fossil and solar plant dismantlement, interim asset removal costs, accretion related to asset retirement obligations (see Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs below), storm recovery amortization and amortization of pre-construction costs associated with planned nuclear units recovered through a cost recovery clause. For substantially all of FPL's property, depreciation studies are typically performed and filed with the FPSC every four years. As part of the 2016 rate agreement, the FPSC approved new depreciation rates which became effective January 1, 2017. In accordance with the 2016 rate agreement discussed in Rate Regulation above, FPL recorded reserve amortization (reversal) of approximately $(357) million, $(541) million and $1,250 million in 2019, 2018 and 2017, respectively. Reserve amortization is recorded as a reduction to (or when reversed as an increase to) accrued asset removal costs which is reflected in noncurrent regulatory liabilities on NEE's and FPL's consolidated balance sheets. In 2017, FPL used available reserve amortization to offset nearly all of the Hurricane Irma storm restoration costs that were expensed, and FPL is partially restoring the reserve amortization through tax savings generated during the term of the 2016 rate agreement. See Note 6. In 2019, FPL used available reserve amortization resulting from operational efficiencies generated at the business to offset all of the Hurricane Dorian storm restoration costs that were expensed. See Storm Fund, Storm Reserve and Storm Restoration Costs below. The weighted annual composite depreciation and amortization rate for FPL's electric utility plant in service, including capitalized software, but excluding

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the effects of decommissioning, dismantlement and the depreciation adjustments discussed above, was approximately 3.9%, 3.8% and 3.7% for 2019, 2018 and 2017, respectively. FPL files a twelve-month forecast with the FPSC each year which contains a regulatory ROE intended to be earned based on the best information FPL has at that time assuming normal weather. This forecast establishes a fixed targeted regulatory ROE. In order to earn the targeted regulatory ROE in each reporting period under the 2016 rate agreement, reserve amortization is calculated using a trailing thirteen-month average of retail rate base and capital structure in conjunction with the trailing twelve months regulatory retail base net operating income, which primarily includes the retail base portion of base and other revenues, net of O&M, depreciation and amortization, interest and tax expenses. In general, the net impact of these income statement line items is adjusted, in part, by reserve amortization or its reversal to earn the targeted regulatory ROE.

NEER's electric plant in service less salvage value, if any, are depreciated primarily using the straight-line method over their estimated useful lives. At December 31, 2019, wind, solar and nuclear plants represented approximately 54%, 12% and 10%, respectively, of NEER's depreciable electric plant in service and other property; the respective amounts at December 31, 2018 were 53%, 14% and 10%. The estimated useful lives of NEER's plants range primarily from 25 to 35 years for wind plants, 25 to 30 years for solar plants and 23 to 47 years for nuclear plants (see Note 5 - Nonrecurring Fair Value Measurements). NEER reviews the estimated useful lives of its fixed assets on an ongoing basis. NEER's oil and gas production assets, representing approximately 15% and 13%, respectively, of NEER's depreciable electric plant in service and other property at December 31, 2019 and 2018, are accounted for under the successful efforts method. Depletion expenses for the acquisition of reserve rights and development costs are recognized using the unit of production method.

*Nuclear Fuel* - FPL and NEER have several contracts for the supply of uranium and the conversion, enrichment and fabrication of nuclear fuel. See Note 15 - Contracts. FPL's and NEER's nuclear fuel costs are charged to fuel expense on a unit of production method.

*Construction Activity* - Allowance for funds used during construction (AFUDC) is a noncash item which represents the allowed cost of capital, including an ROE, used to finance construction projects. FPL records the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and the remainder as other income. FPSC rules limit the recording of AFUDC to projects that have an estimated cost in excess of 0.5% of a utility's plant in service balance and require more than one year to complete. FPSC rules allow construction projects below the 0.5% threshold as a component of rate base. During 2019, 2018 and 2017, FPL capitalized AFUDC at a rate of 6.22%, 5.97% and 6.16%, respectively, which amounted to approximately $80 million, $114 million and $101 million, respectively. See Note 15 - Commitments.

FPL's construction work in progress includes construction materials, progress payments on major equipment contracts, engineering costs, AFUDC and other costs directly associated with the construction of various projects. Upon completion of the projects, these costs are transferred to electric utility plant in service and other property. Capitalized costs associated with construction activities are charged to O&M expenses when recoverability is no longer probable.

NEER capitalizes project development costs once it is probable that such costs will be realized through the ultimate construction of a power plant or sale of development rights. At December 31, 2019 and 2018, NEER's capitalized development costs totaled approximately $651 million and $630 million, respectively, which are included in noncurrent other assets on NEE's consolidated balance sheets. These costs include land rights and other third-party costs directly associated with the development of a new project. Upon commencement of construction, these costs either are transferred to construction work in progress or remain in other assets, depending upon the nature of the cost. Capitalized development costs are charged to O&M expenses when it is no longer probable that these costs will be realized.

NEER's construction work in progress includes construction materials, progress payments on major equipment contracts, third-party engineering costs, capitalized interest and other costs directly associated with the construction and development of various projects. Interest capitalized on construction projects amounted to approximately $135 million, $94 million and $89 million during 2019, 2018 and 2017, respectively. Interest expense allocated from NextEra Energy Capital Holdings, Inc. (NEECH) to NEER is based on a deemed capital structure of 70% debt and differential membership interests sold by NextEra Energy Resources' subsidiaries. Upon commencement of project operation, costs associated with construction work in progress are transferred to electric plant in service and other property. In September 2019, NEER determined it was no longer moving forward with the construction of a 220 MW wind facility due to unresolved permitting issues. NEE recorded charges of approximately $72 million ($54 million after tax), which are included in impairment charges in NEE’s consolidated statements of income for the year ended December 31, 2019, primarily related to the write-off of capitalized construction costs.

*Asset Retirement Obligations* - NEE and FPL each account for asset retirement obligations and conditional asset retirement obligations (collectively, AROs) under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as part of the carrying amount of the long-lived assets. NEE's AROs relate primarily to decommissioning obligations of FPL's and NEER's nuclear units and to obligations for the dismantlement of certain of NEER's wind and solar facilities. See Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs below and Note 13.

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For NEE's rate-regulated operations, including FPL, the asset retirement cost is subsequently allocated to a regulatory liability using a systematic and rational method over the asset's estimated useful life. Changes in the ARO resulting from the passage of time are recognized as an increase in the carrying amount of the ARO and a decrease in the regulatory liability. Changes resulting from revisions to the timing or amount of the original estimate of cash flows are recognized as an increase or a decrease in the ARO and asset retirement cost.

For NEE's non-rate regulated operations, the asset retirement cost is subsequently allocated to expense using a systematic and rational method over the asset's estimated useful life. Changes in the ARO resulting from the passage of time are recognized as an increase in the carrying amount of the liability and as accretion expense, which is included in depreciation and amortization expense in NEE's consolidated statements of income. Changes resulting from revisions to the timing or amount of the original estimate of cash flows are recognized as an increase or a decrease in the asset retirement cost, or income when asset retirement cost is depleted.

*Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs* - For ratemaking purposes, FPL accrues for the cost of end of life retirement and disposal of its nuclear, fossil and solar plants over the expected service life of each unit based on nuclear decommissioning and fossil and solar dismantlement studies periodically filed with the FPSC. In addition, FPL accrues for interim removal costs over the life of the related assets based on depreciation studies approved by the FPSC. As approved by the FPSC, FPL previously suspended its annual decommissioning accrual. Any differences between expense recognized for financial reporting purposes and the amount recovered through rates are reported as a regulatory liability in accordance with regulatory accounting. See Rate Regulation, Electric Plant, Depreciation and Amortization, and Asset Retirement Obligations above and Note 13.

Nuclear decommissioning studies are performed at least every five years and are submitted to the FPSC for approval. FPL filed updated nuclear decommissioning studies with the FPSC in December 2015. These studies reflect, among other things, the expiration dates of the operating licenses for FPL's nuclear units at the time of the studies. The 2015 studies provide for the dismantlement of Turkey Point Units Nos. 3 and 4 following the end of plant operation with decommissioning activities commencing in 2032 and 2033, respectively, and provide for St. Lucie Unit No. 1 to be mothballed beginning in 2036 with decommissioning activities to be integrated with the dismantlement of St. Lucie Unit No. 2 in 2043. These studies also assume that FPL will be storing spent fuel on site pending removal to a United States (U.S.) government facility. After giving effect to the license extensions for Turkey Point Units Nos. 3 and 4, FPL's portion of the ultimate costs of decommissioning its four nuclear units, including costs associated with spent fuel storage above what is expected to be refunded by the U.S. Department of Energy (DOE) under a spent fuel settlement agreement, is estimated to be approximately $9.7 billion, or $3.3 billion expressed in 2019 dollars. FPL intends to reflect the operating license extensions for Turkey Point Units Nos. 3 and 4 in its next nuclear decommissioning studies.

Restricted funds for the payment of future expenditures to decommission FPL's nuclear units are included in nuclear decommissioning reserve funds, which are included in special use funds on NEE's and FPL's consolidated balance sheets. Marketable securities held in the decommissioning funds are primarily carried at fair value. See Note 5. Fund earnings, consisting of dividends, interest and realized gains and losses, net of taxes, are reinvested in the funds. Fund earnings, as well as any changes in unrealized gains and losses, are not recognized in income and are reflected as a corresponding offset in the related regulatory asset or liability accounts. FPL does not currently make contributions to the decommissioning funds, other than the reinvestment of fund earnings. During 2019, 2018 and 2017 fund earnings on decommissioning funds were approximately $125 million, $94 million and $114 million, respectively. The tax effects of amounts not yet recognized for tax purposes are included in deferred income taxes.

Fossil and solar plant dismantlement studies are typically performed at least every four years and are submitted to the FPSC for approval. As part of the 2016 rate agreement, the FPSC approved an annual expense of $26 million based on FPL's 2016 fossil and solar dismantlement studies, which became effective January 1, 2017, and is recorded in depreciation and amortization expense in NEE's and FPL's consolidated statements of income. At December 31, 2019, FPL's portion of the ultimate cost to dismantle its fossil and solar units is approximately $1.2 billion, or $510 million expressed in 2019 dollars.

NEER's AROs include nuclear decommissioning liabilities for Seabrook Station (Seabrook), Duane Arnold Energy Center (Duane Arnold) and Point Beach Nuclear Power Plant (Point Beach) and dismantlement liabilities for its wind and solar facilities. The liabilities are being accreted using the interest method through the date decommissioning or dismantlement activities are expected to be complete. See Note 13. At December 31, 2019 and 2018, NEER's ARO was approximately $1,097 million and $988 million, respectively, and was primarily determined using various internal and external data and applying a probability percentage to a variety of scenarios regarding the life of the plant and timing of decommissioning or dismantlement. NEER's portion of the ultimate cost of decommissioning its nuclear plants, including costs associated with spent fuel storage above what is expected to be refunded by the DOE under a spent fuel settlement agreement, is estimated to be approximately $9.5 billion, or $2.0 billion expressed in 2019 dollars. The ultimate cost to dismantle NEER's wind and solar facilities is estimated to be approximately $1.8 billion.

Seabrook files a comprehensive nuclear decommissioning study with the New Hampshire Nuclear Decommissioning Financing Committee (NDFC) every four years; the most recent study was filed in 2019. Seabrook's decommissioning funding plan is also subject to annual review by the NDFC. Currently, there are no ongoing decommissioning funding requirements for Seabrook, Duane Arnold and Point Beach, however, the U.S. Nuclear Regulatory Commission (NRC), and in the case of Seabrook, the NDFC, has

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the authority to require additional funding in the future. NEER's portion of Seabrook's, Duane Arnold's and Point Beach's restricted funds for the payment of future expenditures to decommission these plants is included in nuclear decommissioning reserve funds, which are included in special use funds on NEE's consolidated balance sheets. Marketable securities held in the decommissioning funds are primarily carried at fair value. See Note 5. Market adjustments for debt securities result in a corresponding adjustment to other comprehensive income (OCI), except for unrealized losses associated with marketable debt securities considered to be other than temporary, including any credit losses, which are recognized in other - net in NEE's consolidated statements of income. Market adjustments for equity securities are recorded in change in unrealized gains (losses) on equity securities held in NEER's nuclear decommissioning funds - net in NEE's consolidated statements of income. Fund earnings, consisting of dividends, interest and realized gains and losses are recognized in income and are reinvested in the funds. The tax effects of amounts not yet recognized for tax purposes are included in deferred income taxes.

*Major Maintenance Costs* - FPL expenses costs associated with planned fossil maintenance as incurred. FPL recognizes costs associated with planned major nuclear maintenance in accordance with regulatory treatment. FPL defers nuclear maintenance costs for each nuclear unit's planned outage to a regulatory asset as the costs are incurred and amortizes the costs to O&M expense over the period from the end of the current outage to the end of the next planned outage.

NEER uses the deferral method to account for certain planned major maintenance costs. NEER's major maintenance costs for its nuclear generation units and combustion turbines are capitalized (included in noncurrent other assets on NEE's consolidated balance sheets) and amortized to O&M expenses on a unit of production method over the period from the end of the last outage to the beginning of the next planned outage.

*Cash Equivalents* - Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

*Restricted Cash* - At December 31, 2019 and 2018, NEE had approximately $508 million ($118 million for FPL) and $4,615 million ($142 million for FPL), respectively, of restricted cash, of which approximately $411 million ($54 million for FPL) and $89 million ($81 million for FPL), respectively, is included in current other assets and the remaining balance is included in noncurrent other assets on NEE's and FPL's consolidated balance sheets. Restricted cash is primarily related to debt service payments, bond proceeds held for construction at FPL and margin cash collateral requirements, and, at December 31, 2018, also related to cash restricted for the acquisition of Gulf Power Company (Gulf Power) (see Note 8 - Gulf Power Company). In addition, where offsetting positions exist, restricted cash related to margin cash collateral of $139 million is netted against derivative assets and $66 million is netted against derivative liabilities at December 31, 2019 and $184 million is netted against derivative assets at December 31, 2018. See Note 4.

*Allowance for Doubtful Accounts* - FPL maintains an accumulated provision for uncollectible customer accounts receivable that is estimated primarily using a percentage, derived from historical revenue and write-off trends, of the previous four months of revenue. Additional amounts are included in the provision to address specific items that are not considered in the calculation described above. NEER regularly reviews collectibility of its receivables and establishes a provision for losses estimated as a percentage of accounts receivable based on the historical bad debt write-off trends for its retail electricity provider operations and, when necessary, using the specific identification method for all other receivables.

*Inventory* - FPL values materials, supplies and fossil fuel inventory using a weighted-average cost method. NEER's materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost and net realizable value, unless evidence indicates that the weighted-average cost will be recovered with a normal profit upon sale in the ordinary course of business.

*Energy Trading* - NEE provides full energy and capacity requirements services primarily to distribution utilities, which include load-following services and various ancillary services, in certain markets and engages in power and gas marketing and trading activities to optimize the value of electricity and fuel contracts, generation facilities and gas infrastructure assets, as well as to take advantage of projected favorable commodity price movements. Trading contracts that meet the definition of a derivative are accounted for at fair value and realized gains and losses from all trading contracts, including those where physical delivery is required, are recorded net for all periods presented. See Note 4.

*Storm Fund, Storm Reserve and Storm Cost Recovery* - The storm and property insurance reserve fund (storm fund) provides coverage toward FPL's storm damage costs. Marketable securities held in the storm fund are carried at fair value. See Note 5. Fund earnings, consisting of dividends, interest and realized gains and losses, net of taxes, are reinvested in the fund. Fund earnings, as well as any changes in unrealized gains and losses, are not recognized in income and are reflected as a corresponding adjustment to the storm and property insurance reserve (storm reserve). The tax effects of amounts not yet recognized for tax purposes are included in deferred income taxes. The storm fund and storm reserve are included in special use funds and noncurrent regulatory liabilities on NEE's and FPL's consolidated balance sheets.

In March 2017, FPL began recovering from its retail customers, through an interim storm surcharge over a 12-month period, eligible storm restoration costs associated with Hurricane Matthew, a 2016 hurricane, of approximately $201 million ($294 million of recoverable costs less $93 million available in FPL's storm reserve prior to the storm), plus approximately $117 million to replenish the storm reserve to the level authorized in FPL's previous rate agreement. As the portion of the Hurricane Matthew surcharge

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applicable to the replenishment of the storm reserve was billed to customers (which was recorded as operating revenues), the storm reserve was recognized as a regulatory liability and charged to depreciation and amortization expense in NEE's and FPL's consolidated statements of income. As part of a settlement agreement between FPL and the OPC regarding the recovery of storm costs related to Hurricane Matthew, FPL issued a one-time refund to customers in August 2018 totaling approximately $28 million, of which $20 million was for storm costs that were reclassified to property, plant and equipment.

In September 2017, FPL was impacted by Hurricane Irma, which resulted in damage throughout much of FPL's service territory. Damage to FPL property from the hurricane was primarily limited to the transmission and distribution systems. In December 2017, following the enactment of the Tax Cuts and Jobs Act (tax reform) as further discussed in Note 6, FPL determined that it would not seek recovery of Hurricane Irma storm restoration costs of approximately $1.3 billion through a storm surcharge from customers and instead recorded such costs as storm restoration costs in NEE's and FPL's consolidated statements of income. As allowed under the 2016 rate agreement, FPL used available reserve amortization to offset nearly all of the Hurricane Irma storm restoration costs that were expensed, and FPL is partially restoring the reserve amortization through tax savings generated during the term of the 2016 rate agreement.

In September 2019, FPL's service territory was impacted by Hurricane Dorian. FPL incurred approximately $260 million of incremental storm restoration costs, which primarily included costs for pre-staging resources in advance of the storm to repair damage to FPL's distribution system. In December 2019, FPL determined that it would not seek recovery of the Hurricane Dorian storm restoration costs through a storm surcharge from customers and instead recorded such costs as storm restoration costs in NEE's and FPL's consolidated statements of income. FPL used available reserve amortization resulting from operational efficiencies generated at the business to offset all of the Hurricane Dorian storm restoration costs that were expensed.

*Impairment of Long-Lived Assets* - NEE evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying value of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value. In most instances, the fair value is determined by discounting estimated future cash flows using an appropriate interest rate. See Note 5 - Nonrecurring Fair Value Measurements.

*Goodwill and Other Intangible Assets* - NEE's goodwill and other intangible assets are as follows:

| | Weighted-Average Useful Lives | December 31, | |
|---|---|---|---|
| | | **2019** | 2018 |
| | (years) | (millions) | |
| Goodwill (by reporting unit): | | | |
| FPL segment: | | | |
| Florida City Gas | | **$ 291** | $ 293 |
| Other | | **9** | 11 |
| NEER segment: | | | |
| Rate-regulated transmission (see Note 8 - Trans Bay Cable, LLC) | | **610** | — |
| Gas infrastructure | | **487** | 487 |
| Customer supply | | **93** | 72 |
| Generation assets | | **28** | 28 |
| Corporate and Other - Gulf Power (see Note 8 - Gulf Power Company) | | **2,686** | — |
| Total goodwill | | **$ 4,204** | $ 891 |
| Other intangible assets not subject to amortization, primarily land easements | | **$ 135** | $ 135 |
| Other intangible assets subject to amortization: | | | |
| Purchased power agreements | 17 | **$ 401** | $ 625 |
| Other, primarily transmission and development rights and customer lists | 22 | **72** | 34 |
| Total | | **473** | 659 |
| Accumulated amortization | | **(56)** | (86) |
| Total other intangible assets subject to amortization - net | | **$ 417** | $ 573 |

NEE's, including FPL's, goodwill relates to various acquisitions which were accounted for using the purchase method of accounting. Other intangible assets are primarily included in noncurrent other assets on NEE's consolidated balance sheets. NEE's other intangible assets subject to amortization are amortized, primarily on a straight-line basis, over their estimated useful lives. Amortization expense was approximately $18 million, $19 million and $35 million for the years ended December 31, 2019, 2018 and 2017, respectively, and is expected to be approximately $18 million, $14 million, $8 million, $7 million and $4 million for 2020, 2021, 2022, 2023 and 2024, respectively.

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Goodwill and other intangible assets not subject to amortization are assessed for impairment at least annually by applying a fair value-based analysis. Other intangible assets subject to amortization are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows.

*Pension Plan* - NEE records the service cost component of net periodic benefit income to O&M expense and the non-service cost component to other net periodic benefit income in NEE's consolidated statements of income. NEE allocates net periodic pension income to its subsidiaries based on the pensionable earnings of the subsidiaries' employees. Accounting guidance requires recognition of the funded status of the pension plan in the balance sheet, with changes in the funded status recognized in other comprehensive income within shareholders' equity in the year in which the changes occur. Since NEE is the plan sponsor, and its subsidiaries do not have separate rights to the plan assets or direct obligations to their employees, this accounting guidance is reflected at NEE and not allocated to the subsidiaries. The portion of previously unrecognized actuarial gains and losses and prior service costs or credits that are estimated to be allocable to FPL as net periodic (income) cost in future periods and that otherwise would be recorded in accumulated other comprehensive income (AOCI) are classified as regulatory assets and liabilities at NEE in accordance with regulatory treatment.

*Stock-Based Compensation* - NEE accounts for stock-based payment transactions based on grant-date fair value. Compensation costs for awards with graded vesting are recognized on a straight-line basis over the requisite service period for the entire award. Forfeitures of stock-based awards are recognized as they occur. See Note 11 - Stock-Based Compensation.

*Retirement of Long-Term Debt* - For NEE's rate-regulated subsidiaries, including FPL, gains and losses that result from differences in reacquisition cost and the net book value of long-term debt which is retired are deferred as a regulatory asset or liability and amortized to interest expense ratably over the remaining life of the original issue, which is consistent with their treatment in the ratemaking process. NEE's non-rate regulated subsidiaries recognize such differences in interest expense at the time of retirement.

*Income Taxes* - Deferred income taxes are recognized on all significant temporary differences between the financial statement and tax bases of assets and liabilities, and are presented as noncurrent on NEE's and FPL's consolidated balance sheets. In connection with the tax sharing agreement between NEE and certain of its subsidiaries, the income tax provision at each applicable subsidiary reflects the use of the "separate return method," except that tax benefits that could not be used on a separate return basis, but are used on the consolidated tax return, are recorded by the applicable subsidiary that generated the tax benefits. Any remaining consolidated income tax benefits or expenses are recorded at the corporate level. Included in other regulatory assets and other regulatory liabilities on NEE's and FPL's consolidated balance sheets is the revenue equivalent of the difference in deferred income taxes computed under accounting rules, as compared to regulatory accounting rules. The net regulatory liability totaled $4,141 million ($3,745 million for FPL) and $4,074 million ($4,042 million for FPL) at December 31, 2019 and 2018, respectively, and is being amortized in accordance with the regulatory treatment over the estimated lives of the assets or liabilities for which the deferred tax amount was initially recognized.

Production tax credits (PTCs) are recognized as wind energy is generated and sold based on a per kWh rate prescribed in applicable federal and state statutes and are recorded as a reduction of current income taxes payable, unless limited by tax law in which instance they are recorded as deferred tax assets. NEER recognizes ITCs as a reduction to income tax expense when the related energy property is placed into service. FPL recognizes ITCs as a reduction to income tax expense over the depreciable life of the related energy property. At December 31, 2019 and 2018, FPL’s accumulated deferred ITCs were approximately $412 million and $326 million, respectively, and are included in noncurrent regulatory liabilities on NEE's and FPL's consolidated balance sheets. NEE and FPL record a deferred income tax benefit created by the convertible ITCs on the difference between the financial statement and tax bases of renewable property. For NEER, this deferred income tax benefit is recorded in income tax expense in the year that the renewable property is placed in service. For FPL, this deferred income tax benefit is offset by a regulatory liability, which is amortized as a reduction of depreciation expense over the approximate lives of the related renewable property in accordance with the regulatory treatment. At December 31, 2019 and 2018, the net deferred income tax benefits associated with FPL's convertible ITCs were approximately $40 million and $42 million, respectively, and are included in noncurrent regulatory assets and noncurrent regulatory liabilities on NEE's and FPL's consolidated balance sheets.

A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets when it is more likely than not that such assets will not be realized. NEE recognizes interest income (expense) related to unrecognized tax benefits (liabilities) in interest income and interest expense, respectively, net of the amount deferred at FPL. At FPL, the offset to accrued interest receivable (payable) on income taxes is classified as a regulatory liability (regulatory asset) which will be amortized to income (expense) over a five-year period upon settlement in accordance with regulatory treatment. All tax positions taken by NEE in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not threshold. NEE and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states, the most significant of which is Florida, and certain foreign jurisdictions. Federal tax liabilities, with the exception of certain refund claims, are effectively settled for all years prior to 2016. State and foreign tax liabilities, which have varied statutes of limitations regarding additional assessments, are generally effectively settled for years prior to 2015. At December 31, 2019, NEE had unrecognized tax benefits of approximately $79 million that, if recognized, could impact the annual effective income tax rate. The amounts of unrecognized tax benefits and related interest accruals may change

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within the next 12 months; however, NEE and FPL do not expect these changes to have a significant impact on NEE's or FPL's financial statements. See Note 6.

*Sales of Differential Membership Interests* - Certain subsidiaries of NextEra Energy Resources sold Class B membership interests in entities that have ownership interests in wind and solar facilities, with generating capacity totaling approximately 7,087 MW and 473 MW, respectively, at December 31, 2019, to third-party investors. NEE retains a controlling interest in the entities and therefore presents the Class B member interests as noncontrolling interests. Noncontrolling interests represents the portion of net assets in consolidated entities that are not owned by NEE and are reported as a component of equity in NEE's consolidated balance sheet. The third-party investors are allocated earnings, tax attributes and cash flows in accordance with the respective limited liability company agreements. Those economics are allocated primarily to the third-party investors until they receive a targeted return (the flip date) and thereafter to NEE. NEE has the right to call the third-party interests at specified amounts if and when the flip date occurs. NEE has determined the allocation of economics between the controlling party and third-party investor should not follow the respective ownership percentages for each wind and solar project but rather the hypothetical liquidation of book value (HLBV) method based on the governing provisions in each respective limited liability company agreement. Under the HLBV method, the amounts of income and loss attributable to the noncontrolling interest reflects changes in the amount the owners would hypothetically receive at each balance sheet date under the respective liquidation provisions, assuming the net assets of these entities were liquidated at the recorded amounts, after taking into account any capital transactions, such as contributions and distributions, between the entities and the owners. At the point in time that the third-party investor, in hypothetical liquidation, would achieve its targeted return, NEE attributes the additional hypothetical proceeds to the Class B membership interests based on the call price. A loss attributable to noncontrolling interest on NEE's consolidated statements of income represents earnings attributable to NEE. Additionally, net (income) loss attributable to noncontrolling interests in NEE's consolidated statement of income for the year ended December 31, 2018 includes a benefit to NEE of approximately $497 million ($373 million after tax) related to a reduction of differential membership interests as a result of a change in the federal corporate income tax rate effective January 1, 2018. Pursuant to previous accounting guidance, prior to 2018, the proceeds received on the sale of Class B membership interest in entities were deferred and recorded as a liability recognized in benefits associated with differential membership interests - net in NEE's consolidated statements of income as the Class B members received their portion of the economic attributes.

*Redeemable Noncontrolling Interests* - Certain subsidiaries of NextEra Energy Resources sold Class B membership interests in entities that have ownership interests in wind facilities to third-party investors. As specified in the respective limited liability company agreements, if, subject to certain contingencies, certain events occur, including, among others, those that would delay construction or cancel any of the underlying projects, an investor has the option to require NEER to return all or part of its investment. As these potential redemptions are outside of NEER's control, these balances were classified as redeemable noncontrolling interests on NEE's consolidated balance sheet as of December 31, 2019 and 2018. During 2019, certain contingencies were resolved resulting in $395 million of the December 31, 2018 balance being reclassified to noncontrolling interests. The contingencies associated with the December 31, 2019 balance are expected to be resolved in 2020.

*Variable Interest Entities (VIEs)* - An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. NEE and FPL evaluate whether an entity is a VIE whenever reconsideration events as defined by the accounting guidance occur. See Note 9.

*Leases* - NEE and FPL determine if an arrangement is a lease at inception. NEE and FPL recognize a right-of-use (ROU) asset and a lease liability for operating and finance leases by recognizing and measuring leases at the commencement date based on the present value of lease payments over the lease term. For sales type leases, the book value of the leased asset is removed from the balance sheet and a net investment in sales-type lease is recognized based on fixed payments under the contract and the residual value of the asset being leased. NEE and FPL have elected not to apply the recognition requirements to short-term leases and not to separate nonlease components from associated lease components for all classes of underlying assets except for purchased power agreements. ROU assets are included primarily in noncurrent other assets, lease liabilities are included in current and noncurrent other liabilities and net investments in sales-type leases are included in current and noncurrent other assets on NEE's and FPL's consolidated balance sheets. Operating lease expense is included in O&M expenses, amortization expense is included in depreciation and amortization expense and interest income associated with sales-type leases is included in operating revenues in NEE's and FPL's consolidated statements of income. See Note 14.

*Acquisition-Related* - During 2019, 2018 and 2017, NEE and certain of its affiliates incurred costs related to several proposed or completed acquisitions, including transaction costs, integration costs and the payment of certain termination fees, which are included in acquisition-related expenses in NEE's consolidated statements of income. See Note 8.

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*Disposal of Businesses/Assets* - On February 11, 2020, a subsidiary of NextEra Energy Resources completed the sale of its ownership interest in two solar generation facilities located in Spain with a total generating capacity of 99.8 MW for net cash proceeds of approximately €117 million (approximately $128 million), subject to working capital and other adjustments. In connection with the sale, NEE anticipates recording a gain of approximately $260 million (pretax and after tax) in its consolidated statements of income during the three-months ended March 31, 2020. The carrying amounts of the major classes of assets related to the facilities that were classified as held for sale, which are included in current other assets on NEE's consolidated balance sheets, were approximately $440 million at December 31, 2019 and primarily represent property, plant and equipment. Liabilities associated with assets held for sale, which are included in current other liabilities on NEE's consolidated balance sheets, were approximately $647 million at December 31, 2019 and primarily represent long-term debt and interest rate derivatives.

In June 2019, subsidiaries of NextEra Energy Resources completed the sale of ownership interests in three wind generation facilities and three solar generation facilities, including noncontrolling interests in two of the solar facilities, located in the Midwest and West regions of the U.S. with a total net ownership interest in plant capacity (net generating capacity) of 611 MW to a NEP subsidiary for cash proceeds of approximately $1.0 billion, plus working capital of $12 million. A NEER affiliate will continue to operate the facilities included in the sale. In connection with the sale, a gain of approximately $341 million ($259 million after tax) was recorded in NEE's consolidated statements of income for the year ended December 31, 2019, which is included in gains on disposal of businesses/ assets - net, and noncontrolling interests of approximately $118 million were recorded on NEE's consolidated balance sheet.

In 2018, subsidiaries of NextEra Energy Resources completed the sale of its ownership interests in ten wind generation facilities and one solar generation facility located in the Midwest, South and West regions of the U.S. with a total net generating capacity of 1,388 MW to a subsidiary of NEP for net cash proceeds of approximately $1.3 billion, after transaction costs and working capital adjustments and NEP's assumption of approximately $941 million in existing noncontrolling interests related to differential membership investors. In connection with the sale and the related consolidating state income tax effects, a gain of approximately $36 million ($32 million after tax) was recorded in NEE's consolidated statements of income for the year ended December 31, 2018 and is included in gains on disposal of businesses/assets - net.

In 2017, an indirect wholly owned subsidiary of NEE completed the sale of its membership interests in its fiber-optic telecommunications business for net cash proceeds of approximately $1.1 billion, after repayment of $370 million of related long-term debt. In connection with the sale and the related consolidating state income tax effects, a gain of approximately $1.1 billion ($685 million after tax) was recorded in NEE's consolidated statements of income for the year ended December 31, 2017 and is included in gains on disposal of businesses/assets - net.

## 2. Revenue from Contracts with Customers

Revenue is recognized when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The promised goods or services in the majority of NEE's contracts with customers is, at FPL, for the delivery of electricity based on tariff rates approved by the FPSC and, at NEER, for the delivery of energy commodities and the availability of electric capacity and electric transmission.

FPL and NEER generate substantially all of NEE's operating revenues, which primarily include revenues from contracts with customers, as well as derivative and lease transactions at NEER. For the vast majority of contracts with customers, NEE believes that the obligation to deliver energy, capacity or transmission is satisfied over time as the customer simultaneously receives and consumes benefits as NEE performs. In 2019 and 2018, NEE's revenue from contracts with customers was approximately $17.5 billion ($12.1 billion at FPL) and approximately $15.4 billion ($11.8 billion at FPL), respectively. NEE's and FPL's receivables are primarily associated with revenues earned from contracts with customers, as well as derivative and lease transactions at NEER, and consist of both billed and unbilled amounts, which are recorded in customer receivables and other receivables on NEE's and FPL's consolidated balance sheets. Receivables represent unconditional rights to consideration and reflect the differences in timing of revenue recognition and cash collections. For substantially all of NEE's and FPL's receivables, regardless of the type of revenue transaction from which the receivable originated, customer and counterparty credit risk is managed in the same manner and the terms and conditions of payment are similar.

*FPL* - FPL's revenues are derived primarily from tariff-based sales that result from providing electricity to retail customers in Florida with no defined contractual term. Electricity sales to retail customers account for approximately 90% of FPL's operating revenues, the majority of which are to residential customers. FPL's retail customers receive a bill monthly based on the amount of monthly kWh usage with payment due monthly. For these types of sales, FPL recognizes revenue as electricity is delivered and billed to customers, as well as an estimate for electricity delivered and not yet billed. The billed and unbilled amounts represent the value of electricity delivered to the customer. At December 31, 2019 and 2018, FPL's unbilled revenues amounted to approximately $389 million and $432 million, respectively, and are included in customer receivables on NEE's and FPL's consolidated balance sheets.

*NEER* - NEER's revenue from contracts with customers is derived primarily from the sale of energy commodities, electric capacity and electric transmission. For these types of sales, NEER recognizes revenue as energy commodities are delivered and as electric capacity and electric transmission are made available, consistent with the amounts billed to customers based on rates stipulated in the respective contracts as well as an accrual for amounts earned but not yet billed. The amounts billed and accrued represent

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the value of energy or transmission delivered and/or the capacity of energy or transmission available to the customer. Revenues yet to be earned under these contracts, which have maturity dates ranging from 2020 to 2053, will vary based on the volume of energy or transmission delivered and/or available. NEER's customers typically receive bills monthly with payment due within 30 days. Certain contracts with customers contain a fixed price which primarily relate to electric capacity sales associated with independent system operator annual auctions through 2023 and certain power purchase agreements with maturity dates through 2034. At December 31, 2019, NEER expects to record approximately $945 million of revenues related to the fixed price components of such contracts over the remaining terms of the related contracts as the capacity is provided.

## 3. Employee Retirement Benefits

*Employee Pension Plan and Other Benefits Plans* - NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. NEE also has a supplemental executive retirement plan (SERP), which includes a non-qualified supplemental defined benefit pension component that provides benefits to a select group of management and highly compensated employees, and sponsors a contributory postretirement plan for other benefits for retirees of NEE and its subsidiaries meeting certain eligibility requirements. The total accrued benefit cost of the SERP and postretirement plans is approximately $313 million ($167 million for FPL) and $226 million ($187 million for FPL) at December 31, 2019 and 2018, respectively.

Pension Plan Assets, Benefit Obligations and Funded Status - The changes in assets, benefit obligations and the funded status of the pension plan are as follows:

| | 2019 | 2018 |
|---|---|---|
| | (millions) | |
| Change in pension plan assets: | | |
| Fair value of plan assets at January 1 | **$ 3,806** | $ 4,020 |
| Actual return on plan assets | **736** | (69) |
| Benefit payments | **(235)** | (160) |
| Acquisitions[(a)] | **493** | 15 |
| Fair value of plan assets at December 31 | **$ 4,800** | $ 3,806 |
| Change in pension benefit obligation: | | |
| Obligation at January 1 | **$ 2,522** | $ 2,593 |
| Service cost | **80** | 70 |
| Interest cost | **114** | 82 |
| Acquisitions[(a)] | **503** | 15 |
| Special termination benefits[(b)] | **19** | 35 |
| Plan amendments | **3** | — |
| Actuarial losses (gains) - net | **357** | (113) |
| Benefit payments | **(235)** | (160) |
| Obligation at December 31[(c)] | **$ 3,363** | $ 2,522 |
| Funded status: | | |
| Prepaid pension benefit costs at NEE at December 31 | **$ 1,437** | $ 1,284 |
| Prepaid pension benefit costs at FPL at December 31[(d)] | **$ 1,477** | $ 1,407 |

(a) Relates to substantially funded pension obligations in connection with the acquisitions of Gulf Power and Florida City Gas, see Note 8.
(b) Reflects enhanced early retirement programs.
(c) NEE's accumulated pension benefit obligation, which includes no assumption about future salary levels, at December 31, 2019 and 2018 was approximately $3,281 million and $2,479 million, respectively.
(d) Reflects FPL's allocated benefits under NEE's pension plan.

NEE's unrecognized amounts included in accumulated other comprehensive income (loss) yet to be recognized as components of prepaid pension benefit costs are as follows:

| | 2019 | 2018 |
|---|---|---|
| | (millions) | |
| Unrecognized prior service benefit (net of $2 and $2 tax expense, respectively) | **$ 2** | $ 2 |
| Unrecognized losses (net of $37 and $27 tax benefit, respectively) | **(108)** | (71) |
| Total | **$ (106)** | $ (69) |

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NEE's unrecognized amounts included in regulatory assets yet to be recognized as components of net prepaid pension benefit costs are as follows:

| | 2019 | 2018 |
|---|---|---|
| | (millions) | |
| Unrecognized prior service benefit | **$ (2)** | $ (3) |
| Unrecognized losses | **263** | 376 |
| Total | **$ 261** | $ 373 |

The following table provides the assumptions used to determine the benefit obligation for the pension plan. These rates are used in determining net periodic pension income in the following year.

| | 2019 | 2018 |
|---|---|---|
| Discount rate[(a)] | **3.22%** | 4.26% |
| Salary increase | **4.40%** | 4.40% |

(a) The method of estimating the interest cost component of net periodic benefit costs uses a full yield curve approach by applying a specific spot rate along the yield curve.

NEE's investment policy for the pension plan recognizes the benefit of protecting the plan's funded status, thereby avoiding the necessity of future employer contributions. Its broad objectives are to achieve a high rate of total return with a prudent level of risk taking while maintaining sufficient liquidity and diversification to avoid large losses and preserve capital over the long term.

The NEE pension plan fund's current target asset allocation, which is expected to be reached over time, is 45% equity investments, 32% fixed income investments, 13% alternative investments and 10% convertible securities. The pension fund's investment strategy emphasizes traditional investments, broadly diversified across the global equity and fixed income markets, using a combination of different investment styles and vehicles. The pension fund's equity and fixed income holdings consist of both directly held securities as well as commingled investment arrangements such as common and collective trusts, pooled separate accounts, registered investment companies and limited partnerships. The pension fund's convertible security assets are principally direct holdings of convertible securities and include a convertible security oriented limited partnership. The pension fund's alternative investments consist primarily of private equity and real estate oriented investments in limited partnerships as well as absolute return oriented limited partnerships that use a broad range of investment strategies on a global basis.

The fair value measurements of NEE's pension plan assets by fair value hierarchy level are as follows:

| | December 31, 2019[(a)] | | | |
|---|---|---|---|---|
| | **Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | (millions) | | | |
| Equity securities[(b)] | **$ 1,593** | **$ 9** | **$ 3** | **$ 1,605** |
| Equity commingled vehicles[(c)] | **—** | **706** | **—** | **706** |
| U.S. Government and municipal bonds | **95** | **7** | **—** | **102** |
| Corporate debt securities[(d)] | **—** | **247** | **—** | **247** |
| Asset-backed securities | **—** | **416** | **—** | **416** |
| Debt security commingled vehicles[(e)] | **47** | **143** | **—** | **190** |
| Convertible securities[(f)] | **32** | **372** | **—** | **404** |
| Total investments in the fair value hierarchy | **$ 1,767** | **$ 1,900** | **$ 3** | **3,670** |
| Total investments measured at net asset value[(g)] | | | | **1,130** |
| Total fair value of plan assets | | | | **$ 4,800** |

(a) See Note 5 for discussion of fair value measurement techniques and inputs.
(b) Includes foreign investments of $741 million.
(c) Includes foreign investments of $141 million.
(d) Includes foreign investments of $76 million.
(e) Includes foreign investments of $5 million.
(f) Includes foreign investments of $20 million.
(g) Includes foreign investments of $190 million.

| | December 31, 2018[a] | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | (millions) | | | |
| Equity securities[b] | $ 1,030 | $ 11 | $ 2 | $ 1,043 |
| Equity commingled vehicles[c] | — | 638 | — | 638 |
| U.S. Government and municipal bonds | 84 | 11 | — | 95 |
| Corporate debt securities[d] | — | 252 | — | 252 |
| Asset-backed securities | — | 253 | — | 253 |
| Debt security commingled vehicles | — | 133 | — | 133 |
| Convertible securities[e] | 17 | 303 | — | 320 |
| Total investments in the fair value hierarchy | $ 1,131 | $ 1,601 | $ 2 | 2,734 |
| Total investments measured at net asset value[f] | | | | 1,072 |
| Total fair value of plan assets | | | | $ 3,806 |

(a) See Note 5 for discussion of fair value measurement techniques and inputs.
(b) Includes foreign investments of $459 million.
(c) Includes foreign investments of $193 million.
(d) Includes foreign investments of $77 million.
(e) Includes foreign investments of $30 million.
(f) Includes foreign investments of $214 million.

Expected Cash Flows - The following table provides information about benefit payments expected to be paid by the pension plan for each of the following calendar years (in millions):

| | |
|---|---|
| 2020 | $ 211 |
| 2021 | $ 203 |
| 2022 | $ 203 |
| 2023 | $ 206 |
| 2024 | $ 207 |
| 2025 - 2029 | $ 1,044 |

Net Periodic Income - The components of net periodic income for the plans are as follows:

| | Pension Benefits | | | Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| | | | (millions) | | | |
| Service cost | **$ 80** | $ 70 | $ 66 | **$ 1** | $ 1 | $ 1 |
| Interest cost | **114** | 82 | 83 | **9** | 7 | 8 |
| Expected return on plan assets | **(312)** | (276) | (270) | **—** | — | — |
| Amortization of prior service benefit | **(1)** | (1) | (1) | **(15)** | (15) | (10) |
| Special termination benefits | **19** | 35 | 38 | **—** | — | — |
| Postretirement benefits settlement | **—** | — | — | **—** | — | 1 |
| Net periodic income at NEE | **$ (100)** | $ (90) | $ (84) | **$ (5)** | $ (7) | $ — |
| Net periodic income allocated to FPL | **$ (71)** | $ (57) | $ (51) | **$ (4)** | $ (6) | $ — |

Other Comprehensive Income - The components of net periodic income recognized in OCI for the pension plan are as follows:

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| | | (millions) | |
| Net gains (losses) (net of $10 tax benefit, $4 tax benefit and $23 tax expense, respectively) | **$ (36)** | $ (13) | $ 37 |

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Regulatory Assets (Liabilities) - The components of net periodic income recognized during the year in regulatory assets (liabilities) for the pension plan are as follows:

| | 2019 | 2018 |
|---|---|---|
| | (millions) | |
| Unrecognized losses (gains) | **$ (113)** | $ 216 |
| Amortization of prior service cost | **1** | 1 |
| Total | **$ (112)** | $ 217 |

The assumptions used to determine net periodic pension income for the pension plan are as follows:

| | 2019 | 2018 | 2017 |
|---|---|---|---|
| Discount rate | **4.26%** | 3.59% | 4.09% |
| Salary increase | **4.40%** | 4.10% | 4.10% |
| Expected long-term rate of return, net of investment management fees[(a)] | **7.35%** | 7.35% | 7.35% |

(a) In developing the expected long-term rate of return on assets assumption for its pension plan, NEE evaluated input, including other qualitative and quantitative factors, from its actuaries and consultants, as well as information available in the marketplace. NEE considered different models, capital market return assumptions and historical returns for a portfolio with an equity/bond asset mix similar to its pension fund. NEE also considered its pension fund's historical compounded returns.

*Employee Contribution Plan* - NEE offers an employee retirement savings plan which allows eligible participants to contribute a percentage of qualified compensation through payroll deductions. NEE makes matching contributions to participants' accounts. Defined contribution expense pursuant to this plan was approximately $58 million, $54 million and $53 million for NEE ($36 million, $34 million and $33 million for FPL) for the years ended December 31, 2019, 2018 and 2017, respectively.

## 4. Derivative Instruments

NEE and FPL use derivative instruments (primarily swaps, options, futures and forwards) to manage the physical and financial risks inherent in the purchase and sale of fuel and electricity, as well as interest rate and foreign currency exchange rate risk associated primarily with outstanding and expected future debt issuances and borrowings, and to optimize the value of NEER's power generation and gas infrastructure assets. NEE and FPL do not utilize hedge accounting for their cash flow and fair value hedges.

With respect to commodities related to NEE's competitive energy business, NEER employs risk management procedures to conduct its activities related to optimizing the value of its power generation and gas infrastructure assets, providing full energy and capacity requirements services primarily to distribution utilities, and engaging in power and gas marketing and trading activities to take advantage of expected future favorable price movements and changes in the expected volatility of prices in the energy markets. These risk management activities involve the use of derivative instruments executed within prescribed limits to manage the risk associated with fluctuating commodity prices. Transactions in derivative instruments are executed on recognized exchanges or via the over-the-counter (OTC) markets, depending on the most favorable credit terms and market execution factors. For NEER's power generation and gas infrastructure assets, derivative instruments are used to hedge all or a portion of the expected output of these assets. These hedges are designed to reduce the effect of adverse changes in the wholesale forward commodity markets associated with NEER's power generation and gas infrastructure assets. With regard to full energy and capacity requirements services, NEER is required to vary the quantity of energy and related services based on the load demands of the customers served. For this type of transaction, derivative instruments are used to hedge the anticipated electricity quantities required to serve these customers and reduce the effect of unfavorable changes in the forward energy markets. Additionally, NEER takes positions in energy markets based on differences between actual forward market levels and management's view of fundamental market conditions, including supply/demand imbalances, changes in traditional flows of energy, changes in short- and long-term weather patterns and anticipated regulatory and legislative outcomes. NEER uses derivative instruments to realize value from these market dislocations, subject to strict risk management limits around market, operational and credit exposure.

Derivative instruments, when required to be marked to market, are recorded on NEE's and FPL's consolidated balance sheets as either an asset or liability measured at fair value. At FPL, substantially all changes in the derivatives' fair value are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel and purchased power cost recovery clause (fuel clause). For NEE's non-rate regulated operations, predominantly NEER, essentially all changes in the derivatives' fair value for power purchases and sales, fuel sales and trading activities are recognized on a net basis in operating revenues; fuel purchases used in the production of electricity are recognized in fuel, purchased power and interchange expense; and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income. Settlement gains and losses are included within the line items in the consolidated statements of income to which they relate. Transactions for which physical delivery is deemed not to have occurred are presented on a net basis in the consolidated statements of income. For commodity derivatives, NEE believes that, where offsetting positions

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exist at the same location for the same time, the transactions are considered to have been netted and therefore physical delivery has been deemed not to have occurred for financial reporting purposes. Settlements related to derivative instruments are primarily recognized in net cash provided by operating activities in NEE's and FPL's consolidated statements of cash flows.

For interest rate and foreign currency derivative instruments, essentially all changes in the derivatives' fair value, as well as the transaction gain or loss on foreign denominated debt, are recognized in interest expense and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income. At December 31, 2019, NEE's AOCI included amounts related to discontinued interest rate cash flow hedges with expiration dates through March 2035 and foreign currency cash flow hedges with expiration dates through September 2030. Approximately $14 million of net losses included in AOCI at December 31, 2019 is expected to be reclassified into earnings within the next 12 months as the principal and/or interest payments are made. Such amounts assume no change in scheduled principal payments.

*Fair Value of Derivative Instruments* - The tables below present NEE's and FPL's gross derivative positions at December 31, 2019 and December 31, 2018, as required by disclosure rules. However, the majority of the underlying contracts are subject to master netting agreements and generally would not be contractually settled on a gross basis. Therefore, the tables below also present the derivative positions on a net basis, which reflect the offsetting of positions of certain transactions within the portfolio, the contractual ability to settle contracts under master netting arrangements and the netting of margin cash collateral (see Note 5 - Recurring Fair Value Measurements for netting information), as well as the location of the net derivative position on the consolidated balance sheets.

| | December 31, 2019 | | | |
|---|---|---|---|---|
| | Gross Basis | | Net Basis | |
| | Assets | Liabilities | Assets | Liabilities |
| | (millions) | | | |
| NEE: | | | | |
| Commodity contracts | $ 5,050 | $ 3,201 | $ 2,350 | $ 576 |
| Interest rate contracts | 26 | 742 | 9 | 725 |
| Foreign currency contracts | 26 | 38 | 27 | 39 |
| Total fair values | $ 5,102 | $ 3,981 | $ 2,386 | $ 1,340 |
| FPL: | | | | |
| Commodity contracts | $ 4 | $ 14 | $ 3 | $ 13 |
| Net fair value by NEE balance sheet line item: | | | | |
| Current derivative assets[(a)] | | | $ 762 | |
| Noncurrent derivative assets[(b)] | | | 1,624 | |
| Current derivative liabilities[(c)] | | | | $ 344 |
| Current other liabilities[(d)] | | | | 133 |
| Noncurrent derivative liabilities | | | | 863 |
| Total derivatives | | | $ 2,386 | $ 1,340 |
| Net fair value by FPL balance sheet line item: | | | | |
| Current other assets | | | $ 3 | |
| Current other liabilities | | | | $ 12 |
| Noncurrent other liabilities | | | | 1 |
| Total derivatives | | | $ 3 | $ 13 |

(a) Reflects the netting of approximately $2 million in margin cash collateral received from counterparties.
(b) Reflects the netting of approximately $139 million in margin cash collateral received from counterparties.
(c) Reflects the netting of approximately $66 million in margin cash collateral paid to counterparties.
(d) See Note 1 - Disposal of Businesses/Assets.

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| | December 31, 2018 | | | |
|---|---|---|---|---|
| | Gross Basis | | Net Basis | |
| | Assets | Liabilities | Assets | Liabilities |
| | (millions) | | | |
| NEE: | | | | |
| Commodity contracts | $ 4,651 | $ 3,305 | $ 1,840 | $ 683 |
| Interest rate contracts | 56 | 472 | 49 | 465 |
| Foreign currency contracts | 17 | 30 | 30 | 43 |
| Total fair values | $ 4,724 | $ 3,807 | $ 1,919 | $ 1,191 |
| FPL: | | | | |
| Commodity contracts | $ 2 | $ 43 | $ — | $ 41 |
| Net fair value by NEE balance sheet line item: | | | | |
| Current derivative assets[(a)] | | | $ 564 | |
| Noncurrent derivative assets[(b)] | | | 1,355 | |
| Current derivative liabilities | | | | $ 675 |
| Noncurrent derivative liabilities | | | | 516 |
| Total derivatives | | | $ 1,919 | $ 1,191 |
| Net fair value by FPL balance sheet line item: | | | | |
| Current other liabilities | | | | $ 32 |
| Noncurrent other liabilities | | | | 9 |
| Total derivatives | | | $ — | $ 41 |

(a) Reflects the netting of approximately $124 million in margin cash collateral received from counterparties.
(b) Reflects the netting of approximately $65 million in margin cash collateral received from counterparties.

At December 31, 2019 and 2018, NEE had approximately $10 million and $16 million (none at FPL), respectively, in margin cash collateral received from counterparties that was not offset against derivative assets in the above presentation. These amounts are included in current other liabilities on NEE's consolidated balance sheets. Additionally, at December 31, 2019 and 2018, NEE had approximately $360 million and $157 million (none at FPL), respectively, in margin cash collateral paid to counterparties that was not offset against derivative assets or liabilities in the above presentation. These amounts are included in current other assets on NEE's consolidated balance sheets.

*Income Statement Impact of Derivative Instruments* - Gains (losses) related to NEE's derivatives are recorded in NEE's consolidated statements of income as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| | | (millions) | |
| Commodity contracts:[(a)] | | | |
| Operating revenues | **$ 762** | $ 377 | $ 454 |
| Fuel, purchased power and interchange | **—** | (2) | — |
| Foreign currency contracts - interest expense | **(7)** | 19 | 55 |
| Foreign currency contracts - other - net | **—** | — | (4) |
| Interest rate contracts - interest expense | **(699)** | (280) | (223) |
| Losses reclassified from AOCI to interest expense: | | | |
| Interest rate contracts | **(32)** | (30) | (48) |
| Foreign currency contracts | **(4)** | (4) | (81) |
| Total | **$ 20** | $ 80 | $ 153 |

(a) For the years ended December 31, 2019, 2018 and 2017, FPL recorded gains (losses) of approximately $9 million, $(31) million and $(169) million, respectively, related to commodity contracts as regulatory liabilities (assets) on its consolidated balance sheets.

*Notional Volumes of Derivative Instruments* - The following table represents net notional volumes associated with derivative instruments that are required to be reported at fair value in NEE's and FPL's consolidated financial statements. The table includes significant volumes of transactions that have minimal exposure to commodity price changes because they are variably priced

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agreements. These volumes are only an indication of the commodity exposure that is managed through the use of derivatives. They do not represent net physical asset positions or non-derivative positions and their hedges, nor do they represent NEE's and FPL's net economic exposure, but only the net notional derivative positions that fully or partially hedge the related asset positions. NEE and FPL had derivative commodity contracts for the following net notional volumes:

| | December 31, 2019 | | | | December 31, 2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Commodity Type | NEE | | FPL | | NEE | | FPL | |
| | (millions) | | | | | | | |
| Power | **(81)** | **MWh[a]** | **1** | **MWh[a]** | (100) | MWh[a] | 1 | MWh[a] |
| Natural gas | **(1,723)** | **MMBtu[b]** | **161** | **MMBtu[b]** | (491) | MMBtu[b] | 231 | MMBtu[b] |
| Oil | **(13)** | **barrels** | **—** | | (30) | barrels | — | |

(a) Megawatt-hours
(b) One million British thermal units

At December 31, 2019 and 2018, NEE had interest rate contracts with a net notional amount of approximately $8.9 billion and $13.4 billion, respectively, and foreign currency contracts with a net notional amount of approximately $1.0 billion and $656 million, respectively.

*Credit-Risk-Related Contingent Features* - Certain derivative instruments contain credit-risk-related contingent features including, among other things, the requirement to maintain an investment grade credit rating from specified credit rating agencies and certain financial ratios, as well as credit-related cross-default and material adverse change triggers. At December 31, 2019 and 2018, the aggregate fair value of NEE's derivative instruments with credit-risk-related contingent features that were in a liability position was approximately $1.7 billion ($12 million for FPL) and $1.8 billion ($34 million for FPL), respectively.

If the credit-risk-related contingent features underlying these derivative agreements were triggered, certain subsidiaries of NEE, including FPL, could be required to post collateral or settle contracts according to contractual terms which generally allow netting of contracts in offsetting positions. Certain derivative contracts contain multiple types of credit-related triggers. To the extent these contracts contain a credit ratings downgrade trigger, the maximum exposure is included in the following credit ratings collateral posting requirements. If FPL's and NEECH's credit ratings were downgraded to BBB/Baa2 (a three level downgrade for FPL and a one level downgrade for NEECH from the current lowest applicable rating), applicable NEE subsidiaries would be required to post collateral such that the total posted collateral would be approximately $215 million (none at FPL) and $270 million (none at FPL) at December 31, 2019 and 2018, respectively. If FPL's and NEECH's credit ratings were downgraded to below investment grade, applicable NEE subsidiaries would be required to post additional collateral such that the total posted collateral would be approximately $1.2 billion ($35 million at FPL) and $1.5 billion ($45 million at FPL) at December 31, 2019 and 2018, respectively. Some derivative contracts do not contain credit ratings downgrade triggers, but do contain provisions that require certain financial measures be maintained and/or have credit-related cross-default triggers. In the event these provisions were triggered, applicable NEE subsidiaries could be required to post additional collateral of up to approximately $590 million ($75 million at FPL) and $610 million ($145 million at FPL) at December 31, 2019 and 2018, respectively.

Collateral related to derivatives may be posted in the form of cash or credit support in the normal course of business. At December 31, 2019 and 2018, applicable NEE subsidiaries have posted approximately $2 million (none at FPL) and $2 million (none at FPL), respectively, in cash and $88 million (none at FPL) and $88 million (none at FPL), respectively, in the form of letters of credit each of which could be applied toward the collateral requirements described above. FPL and NEECH have capacity under their credit facilities generally in excess of the collateral requirements described above that would be available to support, among other things, derivative activities. Under the terms of the credit facilities, maintenance of a specific credit rating is not a condition to drawing on these credit facilities, although there are other conditions to drawing on these credit facilities.

Additionally, some contracts contain certain adequate assurance provisions whereby a counterparty may demand additional collateral based on subjective events and/or conditions. Due to the subjective nature of these provisions, NEE and FPL are unable to determine an exact value for these items and they are not included in any of the quantitative disclosures above.

## 5. Fair Value Measurements

The fair value of assets and liabilities are determined using either unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available and using unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. NEE and FPL use several different valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those assets and liabilities that are measured at fair value on a recurring basis. NEE's and FPL's assessment of the significance of any particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels. Non-performance risk, including the consideration of a credit valuation adjustment, is also considered in the determination of fair value for all assets and liabilities measured at fair value.

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*Cash Equivalents and Restricted Cash Equivalents* - NEE and FPL hold investments in money market funds. The fair value of these funds is estimated using a market approach based on current observable market prices.

*Special Use Funds and Other Investments* - NEE and FPL hold primarily debt and equity securities directly, as well as indirectly through commingled funds. Substantially all directly held equity securities are valued at their quoted market prices. For directly held debt securities, multiple prices and price types are obtained from pricing vendors whenever possible, which enables cross-provider validations. A primary price source is identified based on asset type, class or issue of each security. Commingled funds, which are similar to mutual funds, are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives. The fair value of commingled funds is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

*Derivative Instruments* - NEE and FPL measure the fair value of commodity contracts using a combination of market and income approaches utilizing prices observed on commodities exchanges and in the OTC markets, or through the use of industry-standard valuation techniques, such as option modeling or discounted cash flows techniques, incorporating both observable and unobservable valuation inputs. The resulting measurements are the best estimate of fair value as represented by the transfer of the asset or liability through an orderly transaction in the marketplace at the measurement date.

Most exchange-traded derivative assets and liabilities are valued directly using unadjusted quoted prices. For exchange-traded derivative assets and liabilities where the principal market is deemed to be inactive based on average daily volumes and open interest, the measurement is established using settlement prices from the exchanges, and therefore considered to be valued using other observable inputs.

NEE, through its subsidiaries, including FPL, also enters into OTC commodity contract derivatives. The majority of these contracts are transacted at liquid trading points, and the prices for these contracts are verified using quoted prices in active markets from exchanges, brokers or pricing services for similar contracts.

NEE, through NEER, also enters into full requirements contracts, which, in most cases, meet the definition of derivatives and are measured at fair value. These contracts typically have one or more inputs that are not observable and are significant to the valuation of the contract. In addition, certain exchange and non-exchange traded derivative options at NEE have one or more significant inputs that are not observable, and are valued using industry-standard option models.

In all cases where NEE and FPL use significant unobservable inputs for the valuation of a commodity contract, consideration is given to the assumptions that market participants would use in valuing the asset or liability. The primary input to the valuation models for commodity contracts is the forward commodity curve for the respective instruments. Other inputs include, but are not limited to, assumptions about market liquidity, volatility, correlation and contract duration as more fully described below in Significant Unobservable Inputs Used in Recurring Fair Value Measurements. In instances where the reference markets are deemed to be inactive or do not have transactions for a similar contract, the derivative assets and liabilities may be valued using significant other observable inputs and potentially significant unobservable inputs. In such instances, the valuation for these contracts is established using techniques including extrapolation from or interpolation between actively traded contracts, or estimated basis adjustments from liquid trading points. NEE and FPL regularly evaluate and validate the inputs used to determine fair value by a number of methods, consisting of various market price verification procedures, including the use of pricing services and multiple broker quotes to support the market price of the various commodities. In all cases where there are assumptions and models used to generate inputs for valuing derivative assets and liabilities, the review and verification of the assumptions, models and changes to the models are undertaken by individuals that are independent of those responsible for estimating fair value.

NEE uses interest rate contracts and foreign currency contracts to mitigate and adjust interest rate and foreign currency exchange exposure related primarily to certain outstanding and expected future debt issuances and borrowings when deemed appropriate based on market conditions or when required by financing agreements. NEE estimates the fair value of these derivatives using an income approach based on a discounted cash flows valuation technique utilizing the net amount of estimated future cash inflows and outflows related to the agreements.

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*Recurring Fair Value Measurements* - NEE's and FPL's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level are as follows:

| | December 31, 2019 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Netting[a] | Total |
| | | | (millions) | | |
| Assets: | | | | | |
| Cash equivalents and restricted cash equivalents:[b] | | | | | |
| NEE - equity securities | $ 363 | $ — | $ — | | $ 363 |
| FPL - equity securities | $ 156 | $ — | $ — | | $ 156 |
| Special use funds:[c] | | | | | |
| NEE: | | | | | |
| Equity securities | $ 1,875 | $ 2,088 [d] | $ — | | $ 3,963 |
| U.S. Government and municipal bonds | $ 567 | $ 150 | $ — | | $ 717 |
| Corporate debt securities | $ — | $ 748 | $ — | | $ 748 |
| Mortgage-backed securities | $ — | $ 517 | $ — | | $ 517 |
| Other debt securities | $ — | $ 117 | $ — | | $ 117 |
| FPL: | | | | | |
| Equity securities | $ 596 | $ 1,895 [d] | $ — | | $ 2,491 |
| U.S. Government and municipal bonds | $ 429 | $ 106 | $ — | | $ 535 |
| Corporate debt securities | $ — | $ 533 | $ — | | $ 533 |
| Mortgage-backed securities | $ — | $ 395 | $ — | | $ 395 |
| Other debt securities | $ — | $ 111 | $ — | | $ 111 |
| Other investments:[e] | | | | | |
| NEE: | | | | | |
| Equity securities | $ 34 | $ 12 | $ — | | $ 46 |
| Debt securities | $ 82 | $ 69 | $ — | | $ 151 |
| Derivatives: | | | | | |
| NEE: | | | | | |
| Commodity contracts | $ 1,229 | $ 2,082 | $ 1,739 | $ (2,700) | $ 2,350 [f] |
| Interest rate contracts | $ — | $ 24 | $ 2 | $ (17) | $ 9 [f] |
| Foreign currency contracts | $ — | $ 26 | $ — | $ 1 | $ 27 [f] |
| FPL - commodity contracts | $ — | $ 3 | $ 1 | $ (1) | $ 3 [f] |
| Liabilities: | | | | | |
| Derivatives: | | | | | |
| NEE: | | | | | |
| Commodity contracts | $ 1,365 | $ 1,446 | $ 390 | $ (2,625) | $ 576 [f] |
| Interest rate contracts | $ — | $ 598 | $ 144 | $ (17) | $ 725 [f] |
| Foreign currency contracts | $ — | $ 38 | $ — | $ 1 | $ 39 [f] |
| FPL - commodity contracts | $ — | $ 5 | $ 9 | $ (1) | $ 13 [f] |

(a) Includes the effect of the contractual ability to settle contracts under master netting arrangements and the netting of margin cash collateral payments and receipts. NEE and FPL also have contract settlement receivable and payable balances that are subject to the master netting arrangements but are not offset within the consolidated balance sheets and are recorded in customer receivables - net and accounts payable, respectively.

(b) Includes restricted cash equivalents of approximately $60 million ($54 million for FPL) in current other assets and $64 million ($64 million for FPL) in noncurrent other assets on the consolidated balance sheets.

(c) Excludes investments accounted for under the equity method and loans not measured at fair value on a recurring basis. See Fair Value of Financial Instruments Recorded at Other than Fair Value below.

(d) Primarily invested in commingled funds whose underlying securities would be Level 1 if those securities were held directly by NEE or FPL.

(e) Included in noncurrent other assets in the consolidated balance sheets.

(f) See Note 4 - Fair Value of Derivative Instruments for a reconciliation of net derivatives to NEE's and FPL's consolidated balance sheets.

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| | December 31, 2018 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Netting[a] | Total |
| | | | (millions) | | |
| Assets: | | | | | |
| Cash equivalents and restricted cash equivalents:[b] | | | | | |
| NEE - equity securities | $ 486 | $ — | $ — | | $ 486 |
| FPL - equity securities | $ 206 | $ — | $ — | | $ 206 |
| Special use funds:[c] | | | | | |
| NEE: | | | | | |
| Equity securities | $ 1,445 | $ 1,601 [d] | $ — | | $ 3,046 |
| U.S. Government and municipal bonds | $ 449 | $ 155 | $ — | | $ 604 |
| Corporate debt securities | $ — | $ 728 | $ — | | $ 728 |
| Mortgage-backed securities | $ — | $ 478 | $ — | | $ 478 |
| Other debt securities | $ — | $ 145 | $ 1 | | $ 146 |
| FPL: | | | | | |
| Equity securities | $ 398 | $ 1,452 [d] | $ — | | $ 1,850 |
| U.S. Government and municipal bonds | $ 350 | $ 120 | $ — | | $ 470 |
| Corporate debt securities | $ — | $ 544 | $ — | | $ 544 |
| Mortgage-backed securities | $ — | $ 367 | $ — | | $ 367 |
| Other debt securities | $ — | $ 131 | $ 1 | | $ 132 |
| Other investments:[e] | | | | | |
| NEE: | | | | | |
| Equity securities | $ 13 | $ 11 | $ — | | $ 24 |
| Debt securities | $ 36 | $ 90 | $ — | | $ 126 |
| Derivatives: | | | | | |
| NEE: | | | | | |
| Commodity contracts | $ 1,379 | $ 1,923 | $ 1,349 | $ (2,811) | $ 1,840 [f] |
| Interest rate contracts | $ — | $ 56 | $ — | $ (7) | $ 49 [f] |
| Foreign currency contracts | $ — | $ 17 | $ — | $ 13 | $ 30 [f] |
| FPL - commodity contracts | $ — | $ 2 | $ — | $ (2) | $ — [f] |
| Liabilities: | | | | | |
| Derivatives: | | | | | |
| NEE: | | | | | |
| Commodity contracts | $ 1,329 | $ 1,410 | $ 566 | $ (2,622) | $ 683 [f] |
| Interest rate contracts | $ — | $ 336 | $ 136 | $ (7) | $ 465 [f] |
| Foreign currency contracts | $ — | $ 30 | $ — | $ 13 | $ 43 [f] |
| FPL - commodity contracts | $ — | $ 7 | $ 36 | $ (2) | $ 41 [f] |

(a) Includes the effect of the contractual ability to settle contracts under master netting arrangements and the netting of margin cash collateral payments and receipts. NEE and FPL also have contract settlement receivable and payable balances that are subject to the master netting arrangements but are not offset within the consolidated balance sheets and are recorded in customer receivables - net and accounts payable, respectively.
(b) Includes restricted cash equivalents of approximately $85 million ($81 million for FPL) in current other assets on the consolidated balance sheets.
(c) Excludes investments accounted for under the equity method and loans not measured at fair value on a recurring basis. See Fair Value of Financial Instruments Recorded at Other than Fair Value below.
(d) Primarily invested in commingled funds whose underlying securities would be Level 1 if those securities were held directly by NEE or FPL.
(e) Included in noncurrent other assets in the consolidated balance sheets.
(f) See Note 4 - Fair Value of Derivative Instruments for a reconciliation of net derivatives to NEE's and FPL's consolidated balance sheets.

*Significant Unobservable Inputs Used in Recurring Fair Value Measurements* - The valuation of certain commodity contracts requires the use of significant unobservable inputs. All forward price, implied volatility, implied correlation and interest rate inputs used in the valuation of such contracts are directly based on third-party market data, such as broker quotes and exchange settlements, when that data is available. If third-party market data is not available, then industry standard methodologies are used to develop inputs that maximize the use of relevant observable inputs and minimize the use of unobservable inputs. Observable inputs, including some forward prices, implied volatilities and interest rates used for determining fair value are updated daily to reflect the best available market information. Unobservable inputs which are related to observable inputs, such as illiquid portions of forward price or volatility curves, are updated daily as well, using industry standard techniques such as interpolation and extrapolation, combining observable forward inputs supplemented by historical market and other relevant data. Other unobservable inputs, such as implied correlations, block-to-hourly price shaping, customer migration rates from full requirements contracts and some implied volatility curves, are modeled using proprietary models based on historical data and industry standard techniques.

All price (including block-to-hourly price shaping), volatility, correlation and customer migration inputs used in valuation are subject to validation by the Trading Risk Management group. The Trading Risk Management group performs a risk management function responsible for assessing credit, market and operational risk impact, reviewing valuation methodology and modeling, confirming transactions, monitoring approval processes and developing and monitoring trading limits. The Trading Risk Management group is

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separate from the transacting group. For markets where independent third-party data is readily available, validation is conducted daily by directly reviewing this market data against inputs utilized by the transacting group, and indirectly by reviewing daily risk reports. For markets where independent third-party data is not readily available, additional analytical reviews are performed on at least a quarterly basis. These analytical reviews are designed to ensure that all price and volatility curves used for fair valuing transactions are adequately validated each quarter, and are reviewed and approved by the Trading Risk Management group. In addition, other valuation assumptions such as implied correlations and customer migration rates are reviewed and approved by the Trading Risk Management group on a periodic basis. Newly created models used in the valuation process are also subject to testing and approval by the Trading Risk Management group prior to use and established models are reviewed annually, or more often as needed, by the Trading Risk Management group.

On a monthly basis, the Exposure Management Committee (EMC), which is comprised of certain members of senior management, meets with representatives from the Trading Risk Management group and the transacting group to discuss NEE's and FPL's energy risk profile and operations, to review risk reports and to discuss fair value issues as necessary. The EMC develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with Trading Risk Management policy. The EMC executes its risk management responsibilities through direct oversight and delegation of its responsibilities to the Trading Risk Management group, as well as to other corporate and business unit personnel.

The significant unobservable inputs used in the valuation of NEE's commodity contracts categorized as Level 3 of the fair value hierarchy at December 31, 2019 are as follows:

| Transaction Type | Fair Value at December 31, 2019 | | Valuation Technique(s) | Significant Unobservable Inputs | Range |
|---|---|---|---|---|---|
| | Assets | Liabilities | | | |
| | (millions) | | | | |
| Forward contracts - power | $ 858 | $ 52 | Discounted cash flow | Forward price (per MWh) | $(14) — $258 |
| Forward contracts - gas | 195 | 22 | Discounted cash flow | Forward price (per MMBtu) | $2 — $6 |
| Forward contracts - other commodity related | 3 | 2 | Discounted cash flow | Forward price (various) | $— — $70 |
| Options - power | 42 | 11 | Option models | Implied correlations | 1% — 88% |
| | | | | Implied volatilities | 6% — 502% |
| Options - primarily gas | 152 | 148 | Option models | Implied correlations | 1% — 88% |
| | | | | Implied volatilities | 1% — 218% |
| Full requirements and unit contingent contracts | 489 | 155 | Discounted cash flow | Forward price (per MWh) | $(20) — $949 |
| | | | | Customer migration rate[(a)] | —% — 14% |
| Total | $ 1,739 | $ 390 | | | |

(a) Applies only to full requirements contracts.

The sensitivity of NEE's fair value measurements to increases (decreases) in the significant unobservable inputs is as follows:

| Significant Unobservable Input | Position | Impact on Fair Value Measurement |
|---|---|---|
| Forward price | Purchase power/gas | Increase (decrease) |
| | Sell power/gas | Decrease (increase) |
| Implied correlations | Purchase option | Decrease (increase) |
| | Sell option | Increase (decrease) |
| Implied volatilities | Purchase option | Increase (decrease) |
| | Sell option | Decrease (increase) |
| Customer migration rate | Sell power[(a)] | Decrease (increase) |

(a) Assumes the contract is in a gain position.

In addition, the fair value measurement of interest rate contract net liabilities includes a significant credit valuation adjustment and is primarily related to the solar projects in Spain of approximately $133 million at December 31, 2019. The credit valuation adjustment, considered an unobservable input, reflects management's assessment of non-performance risk of the subsidiaries related to the solar projects in Spain that are party to the contracts.

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The reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs is as follows:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2019 | | 2018 | | 2017 | |
| | NEE | FPL | NEE | FPL | NEE | FPL |
| | (millions) | | | | | |
| Fair value of net derivatives based on significant unobservable inputs at December 31 of prior year | $ 647 | $ (36) | $ 566 | $ — | $ 578 | $ 1 |
| Realized and unrealized gains (losses): | | | | | | |
| Included in earnings[a] | 923 | — | 35 | (1) | 376 | — |
| Included in other comprehensive income (loss)[b] | 5 | — | 7 | — | (18) | — |
| Included in regulatory assets and liabilities | 1 | 1 | (18) | (18) | — | — |
| Purchases | 141 | — | 152 | (16) | 126 | — |
| Settlements | (356) | 25 | 28 | (2) | (317) | (1) |
| Issuances | (87) | — | (115) | — | (197) | — |
| Impact of adoption of revenue standard | — | — | (30) | — | — | — |
| Transfers in[c] | (5) | — | — | — | 17 | — |
| Transfers out[c] | (62) | 2 | 22 | 1 | 1 | — |
| Fair value of net derivatives based on significant unobservable inputs at December 31 | $ 1,207 | $ (8) | $ 647 | $ (36) | $ 566 | $ — |
| Gains (losses) included in earnings attributable to the change in unrealized gains (losses) relating to derivatives held at the reporting date[d] | $ 611 | $ — | $ 100 | $ (1) | $ 277 | $ — |

(a) For the years ended December 31, 2019, 2018 and 2017, approximately $956 million, $48 million and $379 million of realized and unrealized gains are included in the consolidated statements of income in operating revenues and the balance is included in interest expense.
(b) Included in net unrealized gains (losses) on foreign currency translation in the consolidated statements of comprehensive income.
(c) Transfers into Level 3 were a result of decreased observability of market data. Transfers from Level 3 to Level 2 were a result of increased observability of market data. NEE's and FPL's policy is to recognize all transfers at the beginning of the reporting period.
(d) For the years ended December 31, 2019, 2018 and 2017, approximately $638 million, $112 million and $281 million of unrealized gains are included in the consolidated statements of income in operating revenues and the balance is included in interest expense.

*Nonrecurring Fair Value Measurements* - NEE tests long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. A wholly owned subsidiary of NextEra Energy Resources has a power purchase agreement (PPA) with Duane Arnold's primary customer for the energy and capacity related to its 70% ownership share of Duane Arnold that was set to expire on December 31, 2025. NEER had previously expected Duane Arnold would operate at least until the end of its NRC operating license in February 2034. In early December 2017, NEER concluded that it was unlikely that Duane Arnold's primary customer would extend the current PPA after it was set to expire in 2025. Without the long-term cash flow certainty of a PPA for Duane Arnold's energy and capacity, NEER would likely close Duane Arnold on or about December 31, 2025, the end of the term of the PPA. As a result of the change in Duane Arnold's useful life, NEER updated depreciation and ARO estimates to reflect the December 31, 2025 closure. A recoverability analysis performed by NEER determined that the undiscounted cash flows of Duane Arnold were less than its carrying amount and, accordingly, NEER performed a fair value analysis to determine the amount of the impairment. Based on the fair value analysis, long-lived assets (primarily property, plant and equipment) with a carrying amount of approximately $502 million were written down to their fair value of $82 million, resulting in an impairment of $420 million ($258 million after tax), which is included in impairment charges in NEE's consolidated statements of income for the year ended December 31, 2017. The estimate of fair value was based on a combination of the income and market value approaches. The income approach utilized a discounted cash flow valuation technique considering contracted revenue rates (Level 2), annual generation forecasts, annual projected capital and maintenance expenditures and a discount rate (all of which are Level 3). The market value approach utilized a transaction involving a comparable nuclear power plant sale in March 2017 and adjusted for certain entity specific assumptions (Level 3). In January 2019, an amendment to the PPA with Duane Arnold's primary customer became effective which shortened the term of the PPA by five years and results in the PPA expiring on December 31, 2020. Operations of Duane Arnold are expected to cease in late 2020.

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*Fair Value of Financial Instruments Recorded at Other than Fair Value* - The carrying amounts of commercial paper and other short-term debt approximate their fair values. The carrying amounts and estimated fair values of other financial instruments recorded at other than fair value are as follows:

| | December 31, 2019 | | December 31, 2018 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| | (millions) | | | |
| NEE: | | | | |
| Special use funds[(a)] | **$ 892** | **$ 891** | $ 884 | $ 883 |
| Other investments[(b)] | **$ 30** | **$ 30** | $ 54 | $ 54 |
| Long-term debt, including current portion[(c)] | **$ 39,667** | **$ 42,928** [(d)] | $ 29,498 | $ 30,043 [(d)] |
| FPL: | | | | |
| Special use funds[(a)] | **$ 706** | **$ 705** | $ 693 | $ 692 |
| Long-term debt, including current portion | **$ 14,161** | **$ 16,448** [(d)] | $ 11,783 | $ 12,613 [(d)] |

(a) Primarily represents investments accounted for under the equity method and loans not measured at fair value on a recurring basis (Level 2).
(b) Included in noncurrent other assets on NEE's consolidated balance sheets.
(c) Excludes debt totaling approximately $463 million classified as held for sale, which is included in current other liabilities on NEE's consolidated balance sheets, for which the carrying amount approximates fair value. See Note 1 - Disposal of Businesses/Assets.
(d) At December 31, 2019 and 2018, substantially all is Level 2 for NEE and all is Level 2 for FPL.

*Special Use Funds* - The special use funds noted above and those carried at fair value (see Recurring Fair Value Measurements above) consist of NEE's nuclear decommissioning fund assets of approximately $6,880 million and $5,818 million at December 31, 2019 and 2018, respectively, ($4,697 million and $3,987 million, respectively, for FPL) and FPL's storm fund assets of $74 million and $68 million at December 31, 2019 and 2018, respectively. The investments held in the special use funds consist of equity and available for sale debt securities which are primarily carried at estimated fair value. The amortized cost of debt securities is approximately $2,030 million and $1,994 million at December 31, 2019 and 2018, respectively ($1,523 million and $1,542 million, respectively, for FPL).

For FPL's special use funds, changes in fair value, including any other than temporary impairment losses, result in a corresponding adjustment to the related regulatory asset or liability accounts, consistent with regulatory treatment. For NEE's non-rate regulated operations, changes in fair value of debt securities result in a corresponding adjustment to OCI, except for unrealized losses considered to be other than temporary, including any credit losses, which are recognized in other - net in NEE's consolidated statements of income. For NEE's non-rate regulated operations, changes in fair value of equity securities are recorded in change in unrealized gains (losses) on equity securities held in NEER's nuclear decommissioning funds - net in NEE's consolidated statements of income.

The unrealized gains (losses) recognized during the year ended December 31, 2019 and 2018 on equity securities held at December 31, 2019 and 2018 were $780 million ($510 million for FPL) and $(259) million ($(131) million for FPL), respectively. Debt securities included in the nuclear decommissioning funds have a weighted-average maturity at December 31, 2019 of approximately eight years at both NEE and FPL. FPL's storm fund primarily consists of debt securities with a weighted-average maturity at December 31, 2019 of approximately one year. The cost of securities sold is determined using the specific identification method.

Realized gains and losses and proceeds from the sale or maturity of available for sale securities are as follows:

| | NEE | | | FPL | | |
|---|---|---|---|---|---|---|
| | Years Ended December 31, | | | Years Ended December 31, | | |
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| | (millions) | | | | | |
| Realized gains | **$ 68** | $ 51 | $ 178 | **$ 44** | $ 31 | $ 75 |
| Realized losses | **$ 48** | $ 75 | $ 83 | **$ 29** | $ 49 | $ 50 |
| Proceeds from sale or maturity of securities | **$ 3,005** | $ 2,551 | $ 2,817 | **$ 2,539** | $ 2,100 | $ 1,902 |

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The unrealized gains and unrealized losses on available for sale debt securities and the fair value of available for sale debt securities in an unrealized loss position are as follows:

| | NEE | | FPL | |
|---|---|---|---|---|
| | December 31, | | December 31, | |
| | **2019** | 2018 | **2019** | 2018 |
| | (millions) | | | |
| Unrealized gains | **$ 75** | $ 14 | **$ 58** | $ 11 |
| Unrealized losses[(a)] | **$ 7** | $ 52 | **$ 7** | $ 41 |
| Fair value | **$ 314** | $ 1,273 | **$ 240** | $ 961 |

(a) Unrealized losses on available for sale debt securities in an unrealized loss position for greater than twelve months at December 31, 2019 and 2018 were not material to NEE or FPL.

Regulations issued by the FERC and the NRC provide general risk management guidelines to protect nuclear decommissioning funds and to allow such funds to earn a reasonable return. The FERC regulations prohibit, among other investments, investments in any securities of NEE or its subsidiaries, affiliates or associates, excluding investments tied to market indices or mutual funds. Similar restrictions applicable to the decommissioning funds for NEER's nuclear plants are included in the NRC operating licenses for those facilities or in NRC regulations applicable to NRC licensees not in cost-of-service environments. With respect to the decommissioning fund for Seabrook, decommissioning fund contributions and withdrawals are also regulated by the NDFC pursuant to New Hampshire law.

The nuclear decommissioning reserve funds are managed by investment managers who must comply with the guidelines of NEE and FPL and the rules of the applicable regulatory authorities. The funds' assets are invested giving consideration to taxes, liquidity, risk, diversification and other prudent investment objectives.

## 6. Income Taxes

On December 22, 2017, tax reform legislation was signed into law which, among other things, reduced the federal corporate income tax rate from 35% to 21% effective January 1, 2018. As a result, NEE, including FPL, revalued its deferred income taxes as of December 31, 2017. At December 31, 2017, the revaluation reduced NEE's net deferred income tax liabilities by approximately $6.5 billion, of which $4.5 billion related to net deferred income tax liabilities at FPL and the remaining $2 billion related to net deferred income tax liabilities at NEER. The $2 billion reduction in NEER's deferred income tax liabilities increased NEER's 2017 net income. The $4.5 billion reduction in FPL's deferred income tax liabilities was recorded as a regulatory liability. The U.S. Department of Treasury has also released proposed regulations related to the business interest expense limitations and foreign tax credits associated with tax reform. These proposed regulations are not final and are subject to change in the regulatory review process.

The components of income taxes are as follows:

| | NEE | | | FPL | | |
|---|---|---|---|---|---|---|
| | Years Ended December 31, | | | Years Ended December 31, | | |
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| | (millions) | | | | | |
| Federal: | | | | | | |
| Current | **$ 167** | $ 30 | $ 100 | **$ 348** | $ 251 | $ 168 |
| Deferred | **115** | 1,153 | (1,047) | **(29)** | 134 | 776 |
| Total federal | **282** | 1,183 | (947) | **319** | 385 | 944 |
| State: | | | | | | |
| Current | **23** | 63 | 88 | **49** | 91 | 29 |
| Deferred | **143** | 330 | 199 | **73** | 63 | 133 |
| Total state | **166** | 393 | 287 | **122** | 154 | 162 |
| Total income tax expense (benefit) | **$ 448** | $ 1,576 | $ (660) | **$ 441** | $ 539 | $ 1,106 |

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A reconciliation between the effective income tax rates and the applicable statutory rate is as follows:

| | NEE | | | FPL | | |
|---|---|---|---|---|---|---|
| | Years Ended December 31, | | | Years Ended December 31, | | |
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| Statutory federal income tax rate | **21.0%** | 21.0% | 35.0 % | **21.0%** | 21.0% | 35.0% |
| Increases (reductions) resulting from: | | | | | | |
| State income taxes - net of federal income tax benefit | **3.4** | 4.2 | 2.9 | **3.5** | 4.5 | 3.5 |
| Taxes attributable to noncontrolling interests | **2.1** | 2.5 | — | **—** | — | — |
| Tax reform rate change | **—** | — | (41.3) | **—** | — | (0.5) |
| PTCs and ITCs - NEER | **(7.2)** | (3.0) | (8.4) | **—** | — | — |
| Amortization of deferred regulatory credit[(a)] | **(6.2)** | (1.8) | — | **(8.1)** | (5.0) | (0.1) |
| Convertible ITCs - NEER | **—** | — | 0.6 | **—** | — | — |
| Other - net | **(1.4)** | (1.5) | (3.0) | **(0.5)** | (0.6) | (0.9) |
| Effective income tax rate | **11.7%** | 21.4% | (14.2)% | **15.9%** | 19.9% | 37.0% |

(a) 2019 reflects an adjustment of approximately $83 million recorded by FPL to reduce income tax expense for the cumulative amortization of excess deferred income taxes from January 1, 2018 as a result of a FPSC order in connection with its review of impacts associated with tax reform. One of the provisions of the order requires FPL to amortize approximately $870 million of its excess deferred income taxes over a period not to exceed ten years.

The income tax effects of temporary differences giving rise to consolidated deferred income tax liabilities and assets are as follows:

| | NEE | | FPL | |
|---|---|---|---|---|
| | December 31, | | December 31, | |
| | **2019** | 2018 | **2019** | 2018 |
| | (millions) | | | |
| Deferred tax liabilities: | | | | |
| Property-related | **$ 10,133** | $ 9,315 | **$ 6,394** | $ 6,113 |
| Pension | **417** | 374 | **374** | 357 |
| Investments in partnerships and joint ventures | **2,019** | 1,925 | **—** | — |
| Other | **1,618** | 1,505 | **685** | 791 |
| Total deferred tax liabilities | **14,187** | 13,119 | **7,453** | 7,261 |
| Deferred tax assets and valuation allowance: | | | | |
| Decommissioning reserves | **317** | 313 | **286** | 278 |
| Net operating loss carryforwards | **380** | 350 | **2** | 3 |
| Tax credit carryforwards | **3,406** | 3,259 | **—** | — |
| ARO and accrued asset removal costs | **368** | 310 | **273** | 237 |
| Regulatory liabilities | **1,335** | 1,277 | **1,219** | 1,283 |
| Other | **515** | 751 | **258** | 295 |
| Valuation allowance[(a)] | **(285)** | (273) | **—** | — |
| Net deferred tax assets | **6,036** | 5,987 | **2,038** | 2,096 |
| Net deferred income taxes | **$ 8,151** | $ 7,132 | **$ 5,415** | $ 5,165 |

(a) Reflects a valuation allowance related to the solar projects in Spain that completely offsets the related deferred taxes, as well as deferred state tax credits and state operating loss carryforwards.

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Deferred tax assets and liabilities are included on the consolidated balance sheets as follows:

| | NEE | | FPL | |
|---|---|---|---|---|
| | December 31, | | December 31, | |
| | **2019** | 2018 | **2019** | 2018 |
| | (millions) | | | |
| Noncurrent other assets | **$ 210** | $ 235 | **$ —** | $ — |
| Deferred income taxes - noncurrent liabilities | **(8,361)** | (7,367) | **(5,415)** | (5,165) |
| Net deferred income taxes | **$ (8,151)** | $ (7,132) | **$ (5,415)** | $ (5,165) |

The components of NEE's deferred tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2019 are as follows:

| | **Amount** | | **Expiration Dates** |
|---|---|---|---|
| | **(millions)** | | |
| Net operating loss carryforwards: | | | |
| State | **$ 304** | | **2020-2039** |
| Foreign | **76** | **(a)** | **2020-2039** |
| Net operating loss carryforwards | **$ 380** | | |
| Tax credit carryforwards: | | | |
| Federal | **$ 3,060** | | **2029-2039** |
| State | **344** | **(b)** | **2020-2044** |
| Foreign | **2** | | **2034-2039** |
| Tax credit carryforwards | **$ 3,406** | | |

(a) Includes $58 million of net operating loss carryforwards with an indefinite expiration period.
(b) Includes $188 million of ITC carryforwards with an indefinite expiration period.

## 7. Jointly-Owned Electric Plants

Certain NEE subsidiaries own undivided interests in the jointly-owned facilities described below, and are entitled to a proportionate share of the output from those facilities. The subsidiaries are responsible for their share of the operating costs, as well as providing their own financing. Accordingly, each subsidiary's proportionate share of the facilities and related revenues and expenses is included in the appropriate balance sheet and statement of income captions. NEE's and FPL's respective shares of direct expenses for these facilities are included in fuel, purchased power and interchange expense, O&M expenses, depreciation and amortization expense and taxes other than income taxes and other - net in NEE's and FPL's consolidated statements of income.

NEE's and FPL's proportionate ownership interest in jointly-owned facilities is as follows:

| | **December 31, 2019** | | | |
|---|---|---|---|---|
| | **Ownership Interest** | **Gross Investment[a]** | **Accumulated Depreciation[a]** | **Construction Work in Progress** |
| | | | **(millions)** | |
| FPL: | | | | |
| St. Lucie Unit No. 2 | **85%** | **$ 2,226** | **$ 972** | **$ 66** |
| Scherer Unit No. 4 | **76%** | **$ 1,227** | **$ 473** | **$ 55** |
| Gulf Power: | | | | |
| Daniel Units Nos. 1 and 2 | **50%** | **$ 715** | **$ 222** | **$ 22** |
| Scherer Unit No. 3 | **25%** | **$ 423** | **$ 146** | **$ 14** |
| NEER: | | | | |
| Duane Arnold | **70%** | **$ 69** | **$ 41** | **$ —** |
| Seabrook | **88.23%** | **$ 1,270** | **$ 375** | **$ 45** |
| Wyman Station Unit No. 4 | **91.19%** | **$ 29** | **$ 7** | **$ 1** |
| Stanton | **65%** | **$ 137** | **$ 7** | **$ —** |
| Transmission substation assets located in Seabrook, New Hampshire | **88.23%** | **$ 94** | **$ 13** | **$ 14** |

(a) Excludes nuclear fuel.

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## 8. Acquisitions

*Gulf Power Company* - On January 1, 2019, NEE acquired the outstanding common shares of Gulf Power, a rate-regulated electric utility under the jurisdiction of the FPSC. Gulf Power serves approximately 470,000 customers in eight counties throughout northwest Florida, has approximately 9,500 miles of transmission and distribution lines and owns approximately 2,300 MW of net generating capacity. The purchase price included approximately $4.44 billion in cash consideration and the assumption of approximately $1.3 billion of Gulf Power debt. The cash purchase price was funded through $4.5 billion of borrowings by NEECH in December 2018 under certain short-term bi-lateral term loan agreements; the proceeds of which borrowings were restricted and included in noncurrent other assets on NEE's consolidated balance sheet at December 31, 2018. Such borrowings were repaid in April 2019.

Under the acquisition method, the purchase price was allocated to the assets acquired and liabilities assumed on January 1, 2019 based on their fair value. The approval by the FPSC of Gulf Power's rates, which is intended to allow Gulf Power to collect from retail customers total revenues equal to Gulf Power's costs of providing service, including a reasonable rate of return on invested capital, is considered a fundamental input in measuring the fair value of Gulf Power's assets and liabilities and, as such, NEE concluded that the carrying values of all assets and liabilities recoverable through rates are representative of their fair values. As a result, NEE acquired assets of approximately $5.2 billion, primarily relating to property, plant and equipment of $4.0 billion and regulatory assets of $494 million, and assumed liabilities of approximately $3.4 billion, including $1.3 billion of long-term debt, $635 million of regulatory liabilities and $562 million of deferred income taxes. The excess of the purchase price over the fair value of assets acquired and liabilities assumed resulted in approximately $2.7 billion of goodwill which has been recognized on NEE's consolidated balance sheet at December 31, 2019. Goodwill associated with the Gulf Power acquisition is reflected within Corporate and Other and, for impairment testing, is included in the Gulf Power reporting unit. The goodwill arising from the transaction represents expected benefits from continued expansion of NEE's regulated businesses and the indefinite life of Gulf Power's service territory franchise.

*Trans Bay Cable, LLC* - On July 16, 2019, a wholly owned subsidiary of NEET acquired the membership interests of Trans Bay Cable, LLC (Trans Bay), which owns and operates a 53-mile, high-voltage direct current underwater transmission cable system in California extending from Pittsburg to San Francisco, with utility rates set by the FERC and revenues paid by the California Independent System Operator. The purchase price included approximately $670 million in cash consideration and the assumption of debt of approximately $422 million.

Under the acquisition method, the purchase price was allocated to the assets acquired and liabilities assumed based on their fair value. The approval by the FERC of Trans Bay's rates, which is intended to allow Trans Bay to collect total revenues equal to Trans Bay's costs for the development, financing, construction, operation and maintenance of Trans Bay, including a reasonable rate of return on invested capital, is considered a fundamental input in measuring the fair value of Trans Bay's assets and liabilities and, as such, NEE concluded that the carrying values of all assets and liabilities recoverable through rates are representative of their fair values. As a result, NEE acquired assets of approximately $703 million, primarily relating to property, plant and equipment, and assumed liabilities of approximately $643 million, primarily relating to long-term debt. The excess of the purchase price over the fair value of assets acquired and liabilities assumed resulted in approximately $610 million of goodwill which has been recognized on NEE's consolidated balance sheet at December 31, 2019, of which approximately $572 million is expected to be deductible for tax purposes. Goodwill associated with the Trans Bay acquisition is reflected within NEER and, for impairment testing, is included in the rate-regulated transmission reporting unit. The goodwill arising from the transaction represents expected benefits from continued expansion of NEE's regulated businesses. The valuation of the acquired net assets is subject to change as NEE obtains additional information for its estimates during the measurement period.

*Other* - In July 2018, NEE acquired the outstanding common shares of the entity that owns Florida City Gas (FCG), which serves approximately 110,000 residential and commercial natural gas customers in Florida's Miami-Dade, Brevard, St. Lucie and Indian River counties with 3,700 miles of natural gas pipeline, for approximately $530 million in cash subject to certain adjustments. Upon closing, NEE transferred FCG to FPL.

In December 2018, NEE acquired a 100% interest in an entity that indirectly owns Oleander Power Project, an approximately 791 MW natural gas-fired, simple-cycle combustion turbine electric generation facility located near Cocoa, Florida, and a 100% interest in an entity that owns a 65% interest in Stanton Energy Center Unit A, an approximately 660 MW combined-cycle electric generation facility located near Orlando, Florida for approximately $200 million in cash, subject to certain adjustments.

*Santee Cooper* - On February 11, 2020, the South Carolina Department of Administration (DOA) announced that it had selected NEE as the recommended bidder for the sale case in its evaluation process with respect to the South Carolina Public Service Authority, South Carolina's state-owned electric and water utility (Santee Cooper). NEE's proposal provides for the payment of approximately $8.5 billion in cash to repay existing Santee Cooper debt and provide additional proceeds. In addition, NEE's proposal provides approximately $941 million in refunds to Santee Cooper customers. The proposed purchase, which would be structured as an asset purchase, is subject to, among other things, the South Carolina General Assembly enacting a joint resolution approving the proposed purchase, the enactment of comprehensive enabling legislation as South Carolina law, the execution of a definitive asset purchase agreement and the receipt of required regulatory approvals.

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## 9. Variable Interest Entities (VIEs)

At December 31, 2019, NEE had 33 VIEs which it consolidated and had interests in certain other VIEs which it did not consolidate.

*FPL* - FPL is considered the primary beneficiary of, and therefore consolidates, a VIE that is a wholly owned bankruptcy remote special purpose subsidiary that it formed in 2007 for the sole purpose of issuing storm-recovery bonds pursuant to the securitization provisions of the Florida Statutes and a financing order of the FPSC. FPL is considered the primary beneficiary because FPL has the power to direct the significant activities of the VIE, and its equity investment, which was subordinate to the bondholder's interest in the VIE, was at risk. Storm restoration costs incurred by FPL during 2005 and 2004 exceeded the amount in FPL's funded storm and property insurance reserve, resulting in a storm reserve deficiency. In 2007, the VIE issued $652 million aggregate principal amount of senior secured bonds (storm-recovery bonds), primarily for the after-tax equivalent of the total of FPL's unrecovered balance of the 2004 storm restoration costs, the 2005 storm restoration costs and to reestablish FPL's storm and property insurance reserve. In connection with this financing, net proceeds, after debt issuance costs, to the VIE (approximately $644 million) were used to acquire the storm-recovery property, which included the right to impose, collect and receive a storm-recovery charge from all customers receiving electric transmission or distribution service from FPL under rate schedules approved by the FPSC or under special contracts, certain other rights and interests that arose under the financing order issued by the FPSC and certain other collateral pledged by the VIE that issued the bonds. The storm-recovery bonds were payable only from and were secured by the storm-recovery property, and the final payment was made in August 2019. The bondholders had no recourse to the general credit of FPL. The assets and liabilities of the VIE were approximately $77 million and $76 million, respectively, at December 31, 2018, and consisted primarily of storm-recovery property, which were included in current regulatory assets on NEE's and FPL's consolidated balance sheet and storm-recovery bonds, which were included in current portion of long-term debt on NEE's and FPL's consolidated balance sheet.

*NEER* - NEE consolidates 32 VIEs within the NEER segment. Subsidiaries within the NEER segment are considered the primary beneficiary of these VIEs since they control the most significant activities of these VIEs, including operations and maintenance, and they have the obligation to absorb expected losses of these VIEs.

NextEra Energy Resources consolidates two VIEs which own and operate natural gas/oil electric generation facilities with the capability of producing 1,450 MW. These entities sell their electric output under power sales contracts to third parties, with expiration dates in 2021 and 2031. The power sales contracts provide the offtaker the ability to dispatch the facilities and require the offtaker to absorb the cost of fuel. The assets and liabilities of these two VIEs were approximately $216 million and $25 million, respectively, at December 31, 2019. These two VIEs, together with a third VIE that consolidated two separate NEER entities, collectively had assets and liabilities that totaled $257 million and $21 million, respectively, at December 31, 2018. At December 31, 2019 and 2018, the assets of these consolidated VIEs consisted primarily of property, plant and equipment.

Three indirect subsidiaries of NextEra Energy Resources have an approximately 50% ownership interest in five entities which own and operate solar photovoltaic (PV) facilities with the capability of producing a total of approximately 409 MW. Each of the three subsidiaries is considered a VIE since the non-managing members have no substantive rights over the managing members, and is consolidated by NextEra Energy Resources. These five entities sell their electric output to third parties under power sales contracts with expiration dates ranging from 2035 through 2042. The five entities have third-party debt which is secured by liens against the assets of the entities. The debt holders have no recourse to the general credit of NextEra Energy Resources for the repayment of debt. The assets and liabilities of these VIEs were approximately $776 million and $598 million, respectively, at December 31, 2019. There were two consolidated VIEs at December 31, 2018 which owned three entities which had assets and liabilities of $529 million and $557 million, respectively. At December 31, 2019 and 2018, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment and long-term debt.

Beginning in the first quarter of 2019, NEE consolidates a NEET VIE that is constructing an approximately 275-mile electricity transmission line. The NEET subsidiary is the primary beneficiary and controls the most significant activities during the construction period, including controlling the construction budget. Prior to the construction period, the entity was jointly controlled and was accounted for under the equity method. NEET is entitled to receive 50% of the profits and losses of the entity. At December 31, 2019, the assets and liabilities of the VIE totaled $173 million and $29 million, respectively.

The other 26 NextEra Energy Resources VIEs that are consolidated relate to certain subsidiaries which have sold differential membership interests in entities which own and operate wind electric generation and solar PV facilities with the capability of producing a total of approximately 7,081 MW and 473 MW, respectively. These entities sell their electric output either under power sales contracts to third parties with expiration dates ranging from 2029 through 2053 or in the spot market. These entities are considered VIEs because the holders of differential membership interests do not have substantive rights over the significant activities of these entities. Certain entities have third-party debt which is secured by liens against the generation facilities and the other assets of these entities or by pledges of NextEra Energy Resources' ownership interest in these entities. The debt holders have no recourse to the general credit of NEER for the repayment of debt. The assets and liabilities of these VIEs totaled approximately $11.3 billion and $0.8 billion, respectively, at December 31, 2019. There were 25 consolidated VIEs at December 31, 2018, and the assets and liabilities of those VIEs totaled approximately $10.2 billion and $1.4 billion, respectively. At December 31, 2019 and 2018, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment and long-term debt.

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*Other* - At December 31, 2019 and 2018, several NEE subsidiaries had investments totaling approximately $3,247 million ($2,717 million at FPL) and $2,668 million ($2,203 million at FPL), respectively, which are included in special use funds and noncurrent other assets on NEE's consolidated balance sheets and in special use funds on FPL's consolidated balance sheets. These investments represented primarily commingled funds and mortgage-backed securities. NEE subsidiaries, including FPL, are not the primary beneficiaries and therefore do not consolidate any of these entities because they do not control any of the ongoing activities of these entities, were not involved in the initial design of these entities and do not have a controlling financial interest in these entities.

Certain subsidiaries of NEE have noncontrolling interests in entities accounted for under the equity method, including NEE's noncontrolling interest in NEP OpCo. These entities are limited partnerships or similar entity structures in which the limited partners or non-managing members do not have substantive rights over the significant activities of these entities, and therefore are considered VIEs. NEE is not the primary beneficiary because it does not have a controlling financial interest in these entities, and therefore does not consolidate any of these entities. NEE's investment in these entities totaled approximately $4,254 million and $4,680 million at December 31, 2019 and 2018, respectively. At December 31, 2019, subsidiaries of NEE had commitments to invest additional amounts in five of the entities. Such commitments are included in the NEER amounts in the table in Note 15 - Contracts.

## 10. Investments in Partnerships and Joint Ventures

Certain subsidiaries of NEE have noncontrolling interests in various partnerships and joint ventures, essentially all of which own or are in the process of developing natural gas pipelines or own electric generation facilities. At December 31, 2019 and 2018, NEE's investments in partnerships and joint ventures totaled approximately $7,453 million and $6,748 million, respectively, which are included in investment in equity method investees on NEE's consolidated balance sheets. NEE's interest in these partnerships and joint ventures primarily range from approximately 31% to 61%. At December 31, 2019 and 2018, the principal entities included in NEE's investments in partnerships and joint ventures were NEP OpCo, Sabal Trail Transmission, LLC (Sabal Trail) and Mountain Valley Pipeline, LLC, and in 2019 also included Silver State South Solar, LLC.

Summarized combined information for these principal entities is as follows:

| | 2019 | 2018 |
|---|---|---|
| | (millions) | |
| Net income | **$ 128** | $ 632 |
| Total assets | **$ 20,659** | $ 16,334 |
| Total liabilities | **$ 6,956** | $ 5,990 |
| Partners'/members' equity[(a)] | **$ 13,703** | $ 10,344 |
| NEE's share of underlying equity in the principal entities | **$ 3,723** | $ 2,958 |
| Difference between investment carrying amount and underlying equity in net assets[(b)] | **3,153** | 3,193 |
| NEE's investment carrying amount for the principal entities | **$ 6,876** | $ 6,151 |

(a) Reflects NEE's interest, as well as third-party interests, in NEP OpCo.
(b) Primarily associated with NEP OpCo; approximately 70% of the difference between the investment carrying amount and the underlying equity in net assets relates to goodwill and is not being amortized; the remaining balance is being amortized primarily over a period of 20 to 28 years.

NextEra Energy Resources provides management, administrative and transportation and fuel management services to NEP and its subsidiaries under various agreements (service agreements). NextEra Energy Resources is also party to a cash sweep and credit support (CSCS) agreement with a subsidiary of NEP. At December 31, 2019 and 2018, the cash sweep amount (due to NEP and its subsidiaries) held in accounts belonging to NextEra Energy Resources or its subsidiaries was approximately $12 million and $66 million, respectively, and is included in accounts payable. Fee income totaling approximately $101 million and $94 million, respectively, related to the CSCS agreement and the service agreements is included in operating revenues in NEE's consolidated statements of income for the years ended December 31, 2019 and 2018. Amounts due from NEP of approximately $53 million and $45 million are included in other receivables and $33 million and $34 million are included in noncurrent other assets at December 31, 2019 and 2018, respectively. Under the CSCS agreement, NEECH or NEER guaranteed or provided indemnifications, letters of credit or bonds totaling approximately $669 million at December 31, 2019 primarily related to obligations on behalf of NEP's subsidiaries with maturity dates ranging from 2020 to 2059 and included certain project performance obligations, obligations under financing and interconnection agreements and obligations related to the sale of differential membership interests. Payment guarantees and related contracts with respect to unconsolidated entities for which NEE or one of its subsidiaries are the guarantor are recorded on NEE's consolidated balance sheet at fair value. As a result of deconsolidation, approximately $31 million related to the fair value of the credit support provided under the CSCS agreement is recorded as noncurrent other liabilities on NEE's consolidated balance sheet at December 31, 2019.

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## 11. Equity

*Earnings Per Share* - The reconciliation of NEE's basic and diluted earnings per share attributable to NEE is as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2019** | **2018** | **2017** |
| | (millions, except per share amounts) | | |
| Numerator: | | | |
| Net income attributable to NEE - basic | **$ 3,769** | $ 6,638 | $ 5,380 |
| Adjustment for the impact of dilutive securities at NEP(a) | **—** | (19) | — |
| Net income attributable to NEE - assuming dilution | **$ 3,769** | $ 6,619 | $ 5,380 |
| | | | |
| Denominator: | | | |
| Weighted-average number of common shares outstanding - basic | **482.0** | 473.2 | 468.8 |
| Equity units, stock options, performance share awards, forward sale agreements and restricted stock[(b)] | **3.5** | 3.8 | 3.7 |
| Weighted-average number of common shares outstanding - assuming dilution | **485.5** | 477.0 | 472.5 |
| Earnings per share attributable to NEE: | | | |
| Basic | **$ 7.82** | $ 14.03 | $ 11.48 |
| Assuming dilution | **$ 7.76** | $ 13.88 | $ 11.39 |

(a) The 2018 adjustment is related to both the NEP Series A convertible preferred units and the NEP senior unsecured convertible notes (see Potentially Dilutive Securities at NEP below).
(b) Calculated using the treasury stock method. Performance share awards are included in diluted weighted-average number of common shares outstanding based upon what would be issued if the end of the reporting period was the end of the term of the award.

Common shares issuable pursuant to stock options, performance share awards and/or equity units, as well as restricted stock which were not included in the denominator above due to their antidilutive effect were approximately 0.7 million, 0.1 million and 3.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

*Potentially Dilutive Securities at NEP* - In November 2017, NEP issued approximately $550 million of Series A convertible preferred units representing limited partner interests in NEP (NEP preferred units). Holders of NEP preferred units may elect to convert all or any portion of their NEP preferred units into common units of NEP at any time after June 20, 2019 subject to certain conditions. NEP may elect to convert all or any portion of the NEP preferred units that remain outstanding into NEP common units on or after November 15, 2020 if certain conditions are met. At December 31, 2019, the value of the NEP preferred units outstanding was approximately $183 million. In addition, NEP has senior unsecured convertible notes outstanding of $300 million at December 31, 2019. Holders of these notes may convert all or any portion of the notes into NEP common units. The NEP preferred units and NEP senior unsecured convertible notes are potentially dilutive securities to NEE.

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*Forward Sale Agreements* - In November 2016, NEE entered into forward sale agreements with several forward counterparties for 12 million shares of its common stock to be settled on a date or dates to be specified at NEE's direction, no later than November 1, 2017. During 2017, NEE issued 1,711,345 shares of its common stock to net share settle the forward sale agreements. The forward sale price used to determine the net share settlement amount was calculated based on the initial forward sale price of $124.00 per share, less certain adjustments as specified in the forward sale agreements.

*Common Stock Dividend Restrictions* - NEE's charter does not limit the dividends that may be paid on its common stock. FPL's mortgage securing FPL's first mortgage bonds contains provisions which, under certain conditions, restrict the payment of dividends and other distributions to NEE. These restrictions do not currently limit FPL's ability to pay dividends to NEE.

*Stock-Based Compensation* - Net income for the years ended December 31, 2019, 2018 and 2017 includes approximately $100 million, $82 million and $76 million, respectively, of compensation costs and $17 million, $21 million and $29 million, respectively, of income tax benefits related to stock-based compensation arrangements. Compensation cost capitalized for the years ended December 31, 2019, 2018 and 2017 was not material. At December 31, 2019, there were approximately $112 million of unrecognized compensation costs related to nonvested/nonexercisable stock-based compensation arrangements. These costs are expected to be recognized over a weighted-average period of 1.8 years.

At December 31, 2019, approximately 15 million shares of common stock were authorized for awards to officers, employees and non-employee directors of NEE and its subsidiaries under NEE's: (a) Amended and Restated 2011 Long Term Incentive Plan, (b) 2017 Non-Employee Directors Stock Plan and (c) earlier equity compensation plans under which shares are reserved for issuance under existing grants, but no additional shares are available for grant under the earlier plans. NEE satisfies restricted stock and performance share awards by issuing new shares of its common stock or by purchasing shares of its common stock in the open market. NEE satisfies stock option exercises by issuing new shares of its common stock. NEE generally grants most of its stock-based compensation awards in the first quarter of each year.

Restricted Stock and Performance Share Awards - Restricted stock typically vests within three years after the date of grant and is subject to, among other things, restrictions on transferability prior to vesting. The fair value of restricted stock is measured based upon the closing market price of NEE common stock as of the date of grant. Performance share awards are typically payable at the end of a three-year performance period if the specified performance criteria are met. The fair value for the majority of performance share awards is estimated based upon the closing market price of NEE common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple which is subsequently trued up based on actual performance.

The activity in restricted stock and performance share awards for the year ended December 31, 2019 was as follows:

| | Shares | Weighted-Average Grant Date Fair Value Per Share |
|---|---|---|
| Restricted Stock: | | |
| Nonvested balance, January 1, 2019 | 479,936 | $ 134.69 |
| Granted | 235,280 | $ 186.54 |
| Vested | (212,815) | $ 132.15 |
| Forfeited | (7,253) | $ 155.20 |
| Nonvested balance, December 31, 2019 | 495,148 | $ 159.74 |
| Performance Share Awards: | | |
| Nonvested balance, January 1, 2019 | 782,664 | $ 123.47 |
| Granted | 426,777 | $ 138.99 |
| Vested | (522,446) | $ 110.68 |
| Forfeited | (16,849) | $ 157.07 |
| Nonvested balance, December 31, 2019 | 670,146 | $ 142.42 |

The weighted-average grant date fair value per share of restricted stock granted for the years ended December 31, 2018 and 2017 was $155.66 and $130.16 respectively. The weighted-average grant date fair value per share of performance share awards granted for the years ended December 31, 2018 and 2017 was $124.22 and $107.39, respectively.

The total fair value of restricted stock and performance share awards vested was $125 million, $115 million and $96 million for the years ended December 31, 2019, 2018 and 2017, respectively.

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Options - Options typically vest within three years after the date of grant and have a maximum term of ten years. The exercise price of each option granted equals the closing market price of NEE common stock on the date of grant. The fair value of the options is estimated on the date of the grant using the Black-Scholes option-pricing model and based on the following assumptions:

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| Expected volatility[(a)] | **14.20 - 14.31%** | 14.41% | 14.91% |
| Expected dividends | **2.85 - 2.93%** | 3.05% | 3.16% |
| Expected term (years)[(b)] | **7.0** | 7.0 | 7.0 |
| Risk-free rate | **2.24 - 2.54%** | 2.83% | 2.23% |

(a) Based on historical experience.
(b) Based on historical exercise and post-vesting cancellation experience adjusted for outstanding awards.

Option activity for the year ended December 31, 2019 was as follows:

| | Shares Underlying Options | Weighted-Average Exercise Price Per Share | Weighted-Average Remaining Contractual Term (years) | Aggregate Intrinsic Value (millions) |
|---|---|---|---|---|
| Balance, January 1, 2019 | 2,495,630 | $ 96.33 | | |
| Granted | 500,135 | $ 182.95 | | |
| Exercised | (578,093) | $ 59.24 | | |
| Forfeited | (984) | $ 182.61 | | |
| Balance, December 31, 2019 | 2,416,688 | $ 123.09 | **6.2** | $ 288 |
| Exercisable, December 31, 2019 | 1,561,752 | $ 99.22 | **4.9** | $ 223 |

The weighted-average grant date fair value of options granted was $20.03, $18.05 and $13.25 per share for the years ended December 31, 2019, 2018 and 2017, respectively. The total intrinsic value of stock options exercised was approximately $81 million, $35 million and $41 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Cash received from option exercises was approximately $34 million, $18 million and $23 million for the years ended December 31, 2019, 2018 and 2017, respectively. The tax benefits realized from options exercised were approximately $19 million, $9 million and $16 million for the years ended December 31, 2019, 2018 and 2017, respectively.

*Preferred Stock* - NEE's charter authorizes the issuance of 100 million shares of serial preferred stock, $0.01 par value, none of which are outstanding. FPL's charter authorizes the issuance of 10,414,100 shares of preferred stock, $100 par value, 5 million shares of subordinated preferred stock, no par value, and 5 million shares of preferred stock, no par value, none of which are outstanding.

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*Accumulated Other Comprehensive Income (Loss)* - The components of AOCI, net of tax, are as follows:

| | Accumulated Other Comprehensive Income (Loss) | | | | | |
|---|---|---|---|---|---|---|
| | Net Unrealized Gains (Losses) on Cash Flow Hedges | Net Unrealized Gains (Losses) on Available for Sale Securities | Defined Benefit Pension and Other Benefits Plans | Net Unrealized Gains (Losses) on Foreign Currency Translation | Other Comprehensive Income (Loss) Related to Equity Method Investees | Total |
| | | | (millions) | | | |
| Balances, December 31, 2016 | $ (100) | $ 225 | $ (83) | $ (90) | $ (22) | $ (70) |
| Other comprehensive income before reclassifications | — | 127 | 46 | 23 | 2 | 198 |
| Amounts reclassified from AOCI | 32 [(a)] | (36) [(b)] | (2) [(c)] | — | — | (6) |
| Net other comprehensive income | 32 | 91 | 44 | 23 | 2 | 192 |
| Less other comprehensive income attributable to noncontrolling interests | 9 | — | — | 2 | — | 11 |
| Balances, December 31, 2017 | (77) | 316 | (39) | (69) | (20) | 111 |
| Other comprehensive income (loss) before reclassifications | — | (12) | (14) | (31) | 4 | (53) |
| Amounts reclassified from AOCI | 26 [(a)] | 1 [(b)] | (3) [(c)] | — | — | 24 |
| Net other comprehensive income (loss) | 26 | (11) | (17) | (31) | 4 | (29) |
| Impact of NEP deconsolidation[(d)] | 3 | — | — | 37 | 18 | 58 |
| Adoption of accounting standards updates | (7) | (312) | (9) | — | — | (328) |
| Balances, December 31, 2018 | (55) | (7) | (65) | (63) | 2 | (188) |
| Other comprehensive income (loss) before reclassifications | **—** | **20** | **(46)** | **22** | **1** | **(3)** |
| Amounts reclassified from AOCI | **29** [(a)] | **(2)** [(b)] | **(3)** [(c)] | **—** | **—** | **24** |
| Net other comprehensive income (loss) | **29** | **18** | **(49)** | **22** | **1** | **21** |
| Less other comprehensive income attributable to noncontrolling interests | **—** | **—** | **—** | **1** | **—** | **1** |
| Acquisition of Gulf Power (see Note 8) | **(1)** | **—** | **—** | **—** | **—** | **(1)** |
| Balances, December 31, 2019 | **$ (27)** | **$ 11** | **$ (114)** | **$ (42)** | **$ 3** | **$ (169)** |

(a) Reclassified to interest expense in NEE's consolidated statements of income. See Note 4 - Income Statement Impact of Derivative Instruments.
(b) Reclassified to gains on disposal of investments and other property - net in NEE's consolidated statements of income.
(c) Reclassified to other net periodic benefit income in NEE's consolidated statements of income.
(d) Reclassified and included in gain on NEP deconsolidation. See Note 1 - NextEra Energy Partners, LP.

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## 12. Debt

Long-term debt consists of the following:

| | | December 31, | | | |
|---|---|---|---|---|---|
| | | 2019 | | 2018 | |
| | Maturity Date | Balance | Weighted-Average Interest Rate | Balance | Weighted-Average Interest Rate |
| | | (millions) | | (millions) | |
| FPL: | | | | | |
| First mortgage bonds - fixed | 2020-2049 | $ 12,005 | 4.46% | $ 10,626 | 4.60% |
| Storm-recovery bonds - fixed | | — | | 74 | 5.26% |
| Pollution control, solid waste disposal and industrial development revenue bonds - primarily variable[a] | 2020-2049 | 1,076 | 1.67% | 1,022 | 2.04% |
| Senior unsecured notes - variable[b][c] | 2022-2069 | 1,236 | 2.18% | 193 | 2.40% |
| Unamortized debt issuance costs and discount | | (156) | | (132) | |
| Total long-term debt of FPL | | 14,161 | | 11,783 | |
| Less current portion of long-term debt | | 30 | | 95 | |
| Long-term debt of FPL, excluding current portion | | 14,131 | | 11,688 | |
| GULF POWER: | | | | | |
| Senior unsecured notes - fixed | 2020-2044 | 990 | 4.17% | — | |
| Other long-term debt - primarily variable[a] | 2021-2049 | 709 | 1.93% | — | |
| Unamortized debt issuance costs and discount | | (14) | | — | |
| Total long-term debt of Gulf Power | | 1,685 | | — | |
| Less current portion of long-term debt | | 175 | | — | |
| Long-term debt of Gulf Power, excluding current portion | | 1,510 | | — | |
| NEER: | | | | | |
| NextEra Energy Resources: | | | | | |
| Senior secured limited-recourse long-term debt - primarily variable[c][d] | 2023-2049 | 3,419 | 3.79% | 4,193 | 4.38% |
| Other long-term debt - primarily variable[c][d] | 2024-2040 | 440 [e] | 3.78% | 601 | 2.57% |
| NEET - long-term debt - primarily fixed[d] | 2021-2049 | 837 | 3.50% | 325 | 3.73% |
| Unamortized debt issuance costs and premium - net | | (74) | | (95) | |
| Total long-term debt of NEER | | 4,622 | | 5,024 | |
| Less current portion of long-term debt | | 215 | | 602 | |
| Long-term debt of NEER, excluding current portion | | 4,407 | | 4,422 | |
| NEECH: | | | | | |
| Debentures - fixed[d] | 2020-2029 | 9,550 | 3.05% | 4,300 | 3.21% |
| Debentures - variable[c] | 2020-2022 | 1,375 | 3.00% | 2,341 | 3.11% |
| Debentures, related to NEE's equity units - fixed | 2024 | 1,500 | 2.10% | 1,500 | 1.65% |
| Junior subordinated debentures - primarily fixed[d] | 2057-2079 | 4,643 | 5.13% | 3,456 | 4.99% |
| Japanese yen denominated long-term debt - primarily variable[c][d][f] | 2020-2030 | 645 | 3.10% | 637 | 3.10% |
| Australian dollar denominated long-term debt - fixed[f] | 2026 | 351 | 2.59% | — | |
| Other long-term debt - fixed | 2020-2021 | 524 | 2.00% | 543 | 1.95% |
| Other long-term debt - variable[c] | 2021 | 750 | 2.60% | — | |
| Unamortized debt issuance costs and discount | | (139) | | (86) | |
| Total long-term debt of NEECH | | 19,199 | | 12,691 | |
| Less current portion of long-term debt | | 1,704 | | 2,019 | |
| Long-term debt of NEECH, excluding current portion | | 17,495 | | 10,672 | |
| Total long-term debt | | $ 37,543 | | $ 26,782 | |

(a) Includes variable rate tax exempt bonds that permit individual bondholders to tender the bonds for purchase at any time prior to maturity. In the event these variable rate tax exempt bonds are tendered for purchase, they would be remarketed by a designated remarketing agent in accordance with the related indenture. If the remarketing is unsuccessful, FPL or Gulf Power, as the case may be, would be required to purchase the variable rate tax exempt bonds. At December 31, 2019, variable rate tax exempt bonds totaled approximately $948 million at FPL and $269 million at Gulf Power. All variable rate tax exempt bonds tendered for purchase have been successfully remarketed. FPL's and Gulf Power's syndicated revolving credit facilities, as the case may be, are available to support the purchase of the variable rate tax exempt bonds. Variable interest rate is established at various intervals by the remarketing agent. Gulf Power's remaining debt is primarily variable which is based on an underlying index plus a margin.

(b) Includes approximately $236 million of floating rate notes that permit individual noteholders to require repayment prior to maturity. FPL's syndicated revolving credit facilities are available to support the purchase of the senior unsecured notes.

(c) Variable rate is based on an underlying index plus a specified margin.

(d) Interest rate contracts, primarily swaps, have been entered into with respect to certain of these debt issuances. See Note 4.

(e) Excludes approximately $463 million classified as held for sale, which is included in current other liabilities on NEE's consolidated balance sheets. See Note 1 - Disposal of Businesses/Assets.

(f) Foreign currency contracts have been entered into with respect to these debt issuances. See Note 4.

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Minimum annual maturities of long-term debt for NEE are approximately $2,124 million, $4,323 million, $4,134 million, $1,700 million and $3,380 million for 2020, 2021, 2022, 2023 and 2024, respectively. The respective amounts for FPL are approximately $30 million, $68 million, $1,120 million, $537 million and $672 million.

At December 31, 2019 and 2018, short-term borrowings had a weighted-average interest rate of 1.95% (1.80% for FPL) and 2.95% (2.87% for FPL), respectively. Subsidiaries of NEE, including FPL, had credit facilities with available capacity at December 31, 2019 of approximately $10.8 billion ($3.6 billion for FPL), of which approximately $10.7 billion ($3.6 billion for FPL) relate to revolving line of credit facilities and $0.1 billion (none for FPL) relate to letter of credit facilities. Certain of the revolving line of credit facilities provide for the issuance of letters of credit at December 31, 2019 of up to approximately $2.3 billion ($0.6 billion for FPL). The issuance of letters of credit under certain revolving line of credit facilities is subject to the aggregate commitment of the relevant banks to issue letters of credit under the applicable facility. In January 2020, FPL repaid commercial paper of approximately $1.2 billion with proceeds from a capital contribution from NEE.

NEE has guaranteed certain payment obligations of NEECH, including most of those under NEECH's debt, including all of its debentures and commercial paper issuances, as well as most of its payment guarantees and indemnifications. NEECH has guaranteed certain debt and other obligations of subsidiaries within the NEER segment.

In August 2018, NEECH completed a remarketing of approximately $700 million aggregate principal amount of its Series H Debentures due September 1, 2020 (Series H Debentures) that were issued in September 2015 as components of equity units issued concurrently by NEE (September 2015 equity units). The Series H Debentures are fully and unconditionally guaranteed by NEE. In connection with the remarketing of the Series H Debentures, the interest rate on the Series H Debentures was reset to 3.342% per year, and interest is payable on March 1 and September 1 of each year, commencing September 1, 2018. In connection with the settlement of the contracts to purchase NEE common stock that were issued as components of the September 2015 equity units, in the third quarter of 2018, NEE issued 6,215,998 shares of common stock in exchange for $700 million.

In August 2019, NEECH completed a remarketing of $1.5 billion aggregate principal amount of its Series I Debentures due September 1, 2021 (Series I Debentures) that were issued in August 2016 as components of equity units issued concurrently by NEE (August 2016 equity units). The Series I Debentures are fully and unconditionally guaranteed by NEE. In connection with the remarketing of the Series I Debentures, the interest rate on the Series I Debentures was reset to 2.403% per year, and interest is payable on March 1 and September 1 of each year, commencing September 1, 2019. In connection with the settlement of the contracts to purchase NEE common stock that were issued as components of the August 2016 equity units, in the third quarter of 2019, NEE issued 9,543,000 shares of common stock in exchange for $1.5 billion.

In September 2019, NEE sold $1.5 billion of equity units (initially consisting of Corporate Units). Each equity unit has a stated amount of $50 and consists of a contract to purchase NEE common stock (stock purchase contract) and, initially, a 5% undivided beneficial ownership interest in a Series J Debenture due September 1, 2024, issued in the principal amount of $1,000 by NEECH. Each stock purchase contract requires the holder to purchase by no later than September 1, 2022 (the final settlement date) for a price of $50 in cash, a number of shares of NEE common stock (subject to antidilution adjustments) based on a price per share range of $224.12 to $280.15. If purchased on the final settlement date, as of December 31, 2019, the number of shares issued would (subject to antidilution adjustments) range from 0.2231 shares if the applicable market value of a share of common stock is less than or equal to $224.12 to 0.1785 shares if the applicable market value of a share is equal to or greater than $280.15, with applicable market value to be determined using the average closing prices of NEE common stock over a 20-day trading period ending August 29, 2022. Total annual distributions on the equity units are at the rate of 4.872%, consisting of interest on the debentures (2.10% per year) and payments under the stock purchase contracts (2.772% per year). The interest rate on the debentures is expected to be reset on or after March 1, 2022. A holder of an equity unit may satisfy its purchase obligation with proceeds raised from remarketing the NEECH debentures that are part of its equity unit. The undivided beneficial ownership interest in the NEECH debenture that is a component of each Corporate Unit is pledged to NEE to secure the holder's obligation to purchase NEE common stock under the related stock purchase contract. If a successful remarketing does not occur on or before the third business day prior to the final settlement date, and a holder has not notified NEE of its intention to settle the stock purchase contract with cash, the debentures that are components of the Corporate Units will be used to satisfy in full the holders' obligations to purchase NEE common stock under the related stock purchase contracts on the final settlement date. The debentures are fully and unconditionally guaranteed by NEE.

Prior to the issuance of NEE’s common stock, the stock purchase contracts, if dilutive, will be reflected in NEE’s diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of NEE common stock used in calculating diluted earnings per share is deemed to be increased by the excess, if any, of the number of shares that would be issued upon settlement of the stock purchase contracts over the number of shares that could be purchased by NEE in the market, at the average market price during the period, using the proceeds receivable upon settlement.

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## 13. Asset Retirement Obligations

NEE's AROs relate primarily to decommissioning obligations of FPL's and NEER's nuclear units and to obligations for the dismantlement of certain of NEER's wind and solar facilities. For NEE's rate-regulated operations, including FPL, the accounting provisions result in timing differences in the recognition of legal asset retirement costs for financial reporting purposes and the method the regulator allows for recovery in rates. See Note 1 - Rate Regulation and - Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs.

A rollforward of NEE's and FPL's AROs is as follows:

| | NEE | FPL |
|---|---|---|
| | (millions) | |
| Balances, December 31, 2017 | $ 3,031 | $ 2,047 |
| Liabilities incurred | 49 | — |
| Accretion expense | 158 | 101 |
| Liabilities settled | (26) [a] | (1) |
| Revision in estimated cash flows - net | 4 | — |
| Impact of NEP deconsolidation | (81) [b] | — |
| Balances, December 31, 2018 | 3,135 | 2,147 |
| Liabilities incurred | **100** | **1** |
| Accretion expense | **172** | **107** |
| Liabilities settled | **(65)** [a] | **(1)** |
| Revision in estimated cash flows - net | **32** [c] | **14** [c] |
| Additions from acquisitions | **132** [d] | — |
| Balances, December 31, 2019 | **$ 3,506** [e] | **$ 2,268** |

(a) Primarily reflects sales of ownership interests to subsidiaries of NEP. See Note 1 - Disposal of Businesses/Assets.
(b) See Note 1 - NextEra Energy Partners, LP.
(c) Includes an increase of approximately $75 million for additional estimated ash pond closure costs at Scherer, partly offset by a decrease of approximately $71 million due to the approval of Turkey Point Units Nos. 3 and 4 license renewals for an additional 20 years.
(d) See Note 8 for 2019 acquisitions.
(e) Includes the current portion of AROs of approximately $49 million, which is included in other current liabilities on NEE's consolidated balance sheets.

Restricted funds for the payment of future expenditures to decommission NEE's and FPL's nuclear units included in special use funds on NEE's and FPL's consolidated balance sheets are as follows (see Note 5 - Special Use Funds):

| | NEE | FPL |
|---|---|---|
| | (millions) | |
| Balances, December 31, 2019 | **$ 6,880** | **$ 4,697** |
| Balances, December 31, 2018 | $ 5,818 | $ 3,987 |

NEE and FPL have identified but not recognized ARO liabilities related to the majority of their electric transmission and distribution assets and pipelines resulting from easements over property not owned by NEE or FPL. These easements are generally perpetual and only require retirement action upon abandonment or cessation of use of the property or facility for its specified purpose. The related ARO liability is not estimable for such easements as NEE and FPL intend to use these properties indefinitely. In the event NEE and FPL decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

## 14. Leases

NEE has operating and finance leases primarily related to purchased power agreements, land use agreements that convey exclusive use of the land during the arrangement for certain of its renewable energy projects and substations, buildings and equipment. Operating and finance leases primarily have fixed payments with expected expiration dates ranging from 2020 to 2052, with the exception of operating leases related to three land use agreements with an expiration date of 2106, some of which include options to extend the leases up to 27 years and some have options to terminate at NEE's discretion. At December 31, 2019, NEE's ROU assets and lease liabilities for operating leases totaled approximately $499 million and $498 million, respectively; the respective amounts at December 31, 2018 were $133 million and $141 million. At December 31, 2019, NEE's ROU assets and lease liabilities for finance leases totaled approximately $62 million and $56 million, respectively; the respective amounts at December 31, 2018 were $68 million and $63 million. NEE's lease liabilities at December 31, 2019 and 2018 were calculated using a weighted-average incremental borrowing rate at the lease inception of 3.73% and 4.31%, respectively, for operating leases and 3.15% and 2.72%, respectively, for finance leases, and a weighted-average remaining lease term of 31 years and 19 years, respectively, for operating leases and 14 years and 10 years, respectively, for finance leases. At December 31, 2019, expected lease payments over the remaining terms of the leases were approximately $981 million with no one year being material. NEE's operating lease cost for the

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year ended December 31, 2019 totaled approximately $91 million. During the year ended December 31, 2019, NEE's ROU assets obtained in exchange for operating lease obligations totaled approximately $450 million and primarily relate to leases acquired with the Gulf Power and Trans Bay acquisitions (see Note 8). Other operating and finance lease-related amounts were not material to NEE's consolidated statements of income or cash flows for the periods presented.

NEE has sales-type leases primarily related to a natural gas and oil electric generation facility and certain battery storage facilities that sell their electric output under power sales agreements to third parties which provide the customers the ability to dispatch the facilities. At December 31, 2019 and 2018, NEE recorded a net investment in sales-type leases of approximately $50 million and $69 million, respectively, and losses at commencement of sales-type leases due to the variable nature of the lease payments of approximately $20 million for the year ended December 31, 2018, which are recorded in gains on disposal of businesses/assets - net in NEE's consolidated statements of income. At December 31, 2019, the power sales agreements have expiration dates from 2021 to 2043 and NEE expects to receive approximately $150 million of lease payments over the remaining terms of the power sales agreements with no one year being material.

## 15. Commitments and Contingencies

*Commitments* - NEE and its subsidiaries have made commitments in connection with a portion of their projected capital expenditures. Capital expenditures at FPL and Gulf Power include, among other things, the cost for construction of additional facilities and equipment to meet customer demand, as well as capital improvements to and maintenance of existing facilities. At NEER, capital expenditures include, among other things, the cost, including capitalized interest, for construction and development of wind and solar projects, the procurement of nuclear fuel and the cost to maintain existing rate-regulated transmission facilities, as well as equity contributions to joint ventures for the development and construction of natural gas pipeline assets and a rate-regulated transmission facility.

At December 31, 2019, estimated capital expenditures for 2020 through 2024 for which applicable internal approvals (and also, if required, regulatory approvals such as FPSC approvals for FPL and Gulf Power) have been received were as follows:

| | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|
| | | | (millions) | | | |
| FPL: | | | | | | |
| Generation:[a] | | | | | | |
| New[b] | $ 1,345 | $ 730 | $ 555 | $ 500 | $ — | $ 3,130 |
| Existing | 855 | 970 | 930 | 925 | 840 | 4,520 |
| Transmission and distribution[c] | 3,150 | 3,905 | 4,030 | 4,120 | 4,885 | 20,090 |
| Nuclear fuel | 205 | 220 | 165 | 120 | 145 | 855 |
| General and other | 730 | 480 | 440 | 380 | 470 | 2,500 |
| Total | $ 6,285 | $ 6,305 | $ 6,120 | $ 6,045 | $ 6,340 | $ 31,095 |
| Gulf Power | $ 800 | $ 770 | $ 645 | $ 650 | $ 680 | $ 3,545 |
| NEER: | | | | | | |
| Wind[d] | $ 3,265 | $ 20 | $ 10 | $ 10 | $ 10 | $ 3,315 |
| Solar[e] | 945 | 230 | 5 | 5 | — | 1,185 |
| Nuclear, including nuclear fuel | 170 | 180 | 170 | 130 | 150 | 800 |
| Natural gas pipelines[f] | 600 | 195 | 20 | — | — | 815 |
| Rate-regulated transmission | 300 | 110 | 5 | — | — | 415 |
| Other | 580 | 50 | 70 | 60 | 60 | 820 |
| Total | $ 5,860 | $ 785 | $ 280 | $ 205 | $ 220 | $ 7,350 |

(a) Includes AFUDC of approximately $45 million, $70 million, $40 million, and $20 million for 2020 through 2023, respectively.
(b) Includes land, generation structures, transmission interconnection and integration and licensing.
(c) Includes AFUDC of approximately $40 million, $50 million, $40 million, $25 million and $20 million for 2020 through 2024, respectively.
(d) Consists of capital expenditures for new wind projects, repowering of existing wind projects and related transmission totaling approximately 4,400 MW.
(e) Includes capital expenditures for new solar projects and related transmission totaling approximately 1,180 MW.
(f) Construction of two natural gas pipelines are subject to certain conditions, including applicable regulatory approvals. In addition, completion of another natural gas pipeline is subject to final permitting.

The above estimates are subject to continuing review and adjustment and actual capital expenditures may vary significantly from these estimates.

*Contracts* - In addition to the commitments made in connection with the estimated capital expenditures included in the table in Commitments above, FPL has firm commitments under long-term contracts primarily for the transportation of natural gas and coal with expiration dates through 2042.

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At December 31, 2019, NEER has entered into contracts with expiration dates ranging from late February 2020 through 2033 primarily for the purchase of wind turbines, wind towers and solar modules and related construction and development activities, as well as for the supply of uranium, and the conversion, enrichment and fabrication of nuclear fuel, and has made commitments for the construction of natural gas pipelines and a rate-regulated transmission facility. Approximately $3.8 billion of related commitments are included in the estimated capital expenditures table in Commitments above. In addition, NEER has contracts primarily for the transportation and storage of natural gas with expiration dates ranging from March 2020 through 2040.

The required capacity and/or minimum payments under contracts, including those discussed above at December 31, 2019, were estimated as follows:

| | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter |
|---|---|---|---|---|---|---|
| | | | (millions) | | | |
| FPL[(a)] | $ 1,035 | $ 1,005 | $ 985 | $ 975 | $ 970 | $ 11,625 |
| NEER[(b)(c)(d)] | $ 3,355 | $ 395 | $ 255 | $ 130 | $ 140 | $ 1,415 |

(a) Includes approximately $385 million, $415 million, $415 million, $410 million, $410 million and $6,765 million in 2020 through 2024 and thereafter, respectively, of firm commitments related to the natural gas transportation agreements with Sabal Trail and Florida Southeast Connection, LLC. The charges associated with these agreements are recoverable through the fuel clause and totaled approximately $316 million and $303 million for the years ended December 31, 2019 and 2018, respectively, of which $108 million and $95 million, respectively, were eliminated in consolidation at NEE.

(b) Includes approximately $70 million, $70 million, $70 million, $70 million and $1,110 million for 2021 through 2024 and thereafter, respectively, of firm commitments related to a natural gas transportation agreement with a joint venture, in which NEER has a 31% equity investment, that is constructing a natural gas pipeline. These firm commitments are subject to the completion of construction of the pipeline which is expected in 2020.

(c) Includes an approximately $110 million commitment to invest in technology investments through 2029.

(d) Includes approximately $60 million, $20 million, $20 million, $20 million, $10 million and $15 million for 2020 through 2024 and thereafter, respectively, of joint obligations of NEECH and NEER.

*Insurance* - Liability for accidents at nuclear power plants is governed by the Price-Anderson Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both private sources and an industry retrospective payment plan. In accordance with this Act, NEE maintains $450 million of private liability insurance per site, which is the maximum obtainable, and participates in a secondary financial protection system, which provides up to $13.5 billion of liability insurance coverage per incident at any nuclear reactor in the U.S. Under the secondary financial protection system, NEE is subject to retrospective assessments of up to $1.1 billion ($550 million for FPL), plus any applicable taxes, per incident at any nuclear reactor in the U.S., payable at a rate not to exceed $164 million ($82 million for FPL) per incident per year. NEE and FPL are contractually entitled to recover a proportionate share of such assessments from the owners of minority interests in Seabrook, Duane Arnold and St. Lucie Unit No. 2, which approximates $16 million, $41 million and $20 million, plus any applicable taxes, per incident, respectively.

NEE participates in a nuclear insurance mutual company that provides $2.75 billion of limited insurance coverage per occurrence per site for property damage, decontamination and premature decommissioning risks at its nuclear plants and a sublimit of $1.5 billion for non-nuclear perils, except for Duane Arnold which has a sublimit of $500 million. NEE participates in co-insurance of 10% of the first $400 million of losses per site per occurrence. The proceeds from such insurance, however, must first be used for reactor stabilization and site decontamination before they can be used for plant repair. NEE also participates in an insurance program that provides limited coverage for replacement power costs if a nuclear plant is out of service for an extended period of time because of an accident. In the event of an accident at one of NEE's or another participating insured's nuclear plants, NEE could be assessed up to $174 million ($106 million for FPL), plus any applicable taxes, in retrospective premiums in a policy year. NEE and FPL are contractually entitled to recover a proportionate share of such assessments from the owners of minority interests in Seabrook, Duane Arnold and St. Lucie Unit No. 2, which approximates $3 million, $4 million and $4 million, plus any applicable taxes, respectively.

Due to the high cost and limited coverage available from third-party insurers, NEE does not have property insurance coverage for a substantial portion of either its transmission and distribution property or natural gas pipeline assets. If either FPL's or Gulf Power's future storm restoration costs exceed their respective storm reserve, FPL and Gulf Power may recover their storm restoration costs, subject to prudence review by the FPSC, through surcharges approved by the FPSC or through securitization provisions pursuant to Florida law. See Note 1 - Storm Fund, Storm Reserve and Storm Cost Recovery.

In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers in the case of FPL or Gulf Power, would be borne by NEE and either FPL or Gulf Power, and could have a material adverse effect on NEE's and FPL's financial condition, results of operations and liquidity.

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## 16. Segment Information

The table below presents information for NEE's reportable segments, FPL, a rate-regulated utility business, and NEER, which is comprised of competitive energy and rate-regulated transmission businesses, as well as for Gulf Power, a rate-regulated utility business acquired in January 2019. Corporate and Other represents other business activities and includes eliminating entries. During the fourth quarter of 2019, NEET, which was previously reported in Corporate and Other, was moved to the NEER segment. Prior year amounts for NEER and Corporate and Other were adjusted to reflect this segment change. See Note 2 for information regarding NEE's and FPL's operating revenues.

NEE's segment information is as follows:

| | 2019 | | | | |
|---|---|---|---|---|---|
| | FPL | Gulf Power[a] | NEER[b] | Corp. and Other | NEE Consolidated |
| | | | (millions) | | |
| Operating revenues | $ 12,192 | $ 1,487 | $ 5,639 | $ (114) | $ 19,204 |
| Operating expenses - net | $ 8,890 | $ 1,216 | $ 3,635 | $ 110 | $ 13,851 |
| Interest expense | $ 594 | $ 55 | $ 873 | $ 727 | $ 2,249 |
| Interest income | $ 5 | $ 3 | $ 38 | $ 8 | $ 54 |
| Depreciation and amortization | $ 2,524 | $ 247 | $ 1,387 | $ 58 | $ 4,216 |
| Equity in earnings (losses) of equity method investees | $ — | $ — | $ 67 | $ (1) | $ 66 |
| Income tax expense (benefit)[c] | $ 441 | $ 42 | $ 162 | $ (197) | $ 448 |
| Net income (loss) | $ 2,334 | $ 180 | $ 1,426 | $ (552) | $ 3,388 |
| Net income (loss) attributable to NEE | $ 2,334 | $ 180 | $ 1,807 | $ (552) | $ 3,769 |
| Capital expenditures, independent power and other investments and nuclear fuel purchases | $ 5,755 | $ 729 | $ 6,505 | $ 4,473 | $ 17,462 |
| Property, plant and equipment | $ 59,027 | $ 6,393 | $ 41,499 | $ 259 | $ 107,178 |
| Accumulated depreciation and amortization | $ 13,953 | $ 1,630 | $ 9,457 | $ 128 | $ 25,168 |
| Total assets | $ 57,188 | $ 5,855 | $ 51,516 | $ 3,132 | $ 117,691 |
| Investment in equity method investees | $ — | $ — | $ 7,453 | $ — | $ 7,453 |

| | 2018 | | | |
|---|---|---|---|---|
| | FPL | NEER[b][d] | Corp. and Other | NEE Consolidated |
| | | (millions) | | |
| Operating revenues | $ 11,862 | $ 4,984 | $ (119) | $ 16,727 |
| Operating expenses - net | $ 8,708 | $ 3,616 | $ 123 | $ 12,447 |
| Interest expense | $ 541 | $ 595 | $ 362 | $ 1,498 |
| Interest income | $ 4 | $ 40 | $ 7 | $ 51 |
| Depreciation and amortization | $ 2,633 | $ 1,230 | $ 48 | $ 3,911 |
| Equity in earnings of equity method investees | $ — | $ 321 | $ 37 | $ 358 |
| Income tax expense (benefit)[c] | $ 539 | $ 1,196 | $ (159) | $ 1,576 |
| Net income (loss) | $ 2,171 | $ 3,842 | $ (237) | $ 5,776 |
| Net income (loss) attributable to NEE | $ 2,171 | $ 4,704 | $ (237) | $ 6,638 |
| Capital expenditures, independent power and other investments and nuclear fuel purchases | $ 5,135 | $ 7,189 | $ 680 | $ 13,004 |
| Property, plant and equipment | $ 54,717 | $ 37,063 | $ 303 | $ 92,083 |
| Accumulated depreciation and amortization | $ 13,218 | $ 8,461 | $ 70 | $ 21,749 |
| Total assets | $ 53,484 | $ 44,509 | $ 5,709 | $ 103,702 |
| Investment in equity method investees | $ — | $ 6,521 | $ 227 | $ 6,748 |

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| | 2017 | | | |
|---|---|---|---|---|
| | FPL | NEER[b] | Corp. and Other | NEE Consolidated |
| | (millions) | | | |
| Operating revenues | $ 11,972 | $ 5,275 | $ (74) | $ 17,173 |
| Operating expenses - net | $ 8,582 | $ 4,345 | $ (927) | $ 12,000 |
| Interest expense | $ 481 | $ 815 | $ 262 | $ 1,558 |
| Interest income | $ 2 | $ 72 | $ 7 | $ 81 |
| Depreciation and amortization | $ 940 | $ 1,414 | $ 3 | $ 2,357 |
| Equity in earnings of equity method investees | $ — | $ 136 | $ 5 | $ 141 |
| Income tax expense (benefit)[c] | $ 1,106 | $ (2,013) | $ 247 | $ (660) |
| Net income | $ 1,880 | $ 2,940 | $ 503 | $ 5,323 |
| Net income attributable to NEE | $ 1,880 | $ 2,997 | $ 503 | $ 5,380 |
| Capital expenditures, independent power and other investments and nuclear fuel purchases | $ 5,291 | $ 5,415 | $ 34 | $ 10,740 |
| Property, plant and equipment | $ 51,915 | $ 41,567 | $ 83 | $ 93,565 |
| Accumulated depreciation and amortization | $ 12,791 | $ 8,460 | $ 25 | $ 21,276 |
| Total assets | $ 50,254 | $ 46,611 | $ 1,098 | $ 97,963 |
| Investment in equity method investees | $ — | $ 2,173 | $ 148 | $ 2,321 |

(a) See Note 8 - Gulf Power Company.
(b) Interest expense allocated from NEECH is based on a deemed capital structure of 70% debt and differential membership interests sold by NextEra Energy Resources' subsidiaries. Residual NEECH corporate interest expense is included in Corporate and Other.
(c) NEER includes PTCs that were recognized based on its tax sharing agreement with NEE. See Note 1 - Income Taxes.
(d) NEP was deconsolidated from NEER in January 2018. See Note 1 - NextEra Energy Partners, LP.

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## 17. Summarized Financial Information of NEECH

NEECH, a 100% owned subsidiary of NEE, provides funding for, and holds ownership interests in, NEE's operating subsidiaries other than FPL and Gulf Power. NEECH's debentures and junior subordinated debentures including those that were registered pursuant to the Securities Act of 1933, as amended, are fully and unconditionally guaranteed by NEE. Condensed consolidating financial information is as follows:

Condensed Consolidating Statements of Income

| | Year Ended December 31, 2019 | | | | Year Ended December 31, 2018 | | | | Year Ended December 31, 2017 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated |
| | (millions) | | | | | | | | | | | |
| Operating revenues | $ — | $ 5,671 | $13,533 | $ 19,204 | $ — | $ 5,007 | $ 11,720 | $ 16,727 | $ — | $ 5,301 | $ 11,872 | $ 17,173 |
| Operating expenses - net | (209) | (3,669) | (9,973) | (13,851) | (196) | (3,652) | (8,599) | (12,447) | (175) | (3,273) | (8,552) | (12,000) |
| Interest expense | (3) | (1,596) | (650) | (2,249) | (17) | (940) | (541) | (1,498) | (3) | (1,074) | (481) | (1,558) |
| Equity in earnings of subsidiaries | 3,785 | — | (3,785) | — | 6,548 | — | (6,548) | — | 5,393 | — | (5,393) | — |
| Equity in earnings of equity method investees | — | 66 | — | 66 | — | 358 | — | 358 | — | 141 | — | 141 |
| Gain on NEP deconsolidation | — | — | — | — | — | 3,927 | — | 3,927 | — | — | — | — |
| Other income - net | 185 | 407 | 74 | 666 | 169 | 21 | 95 | 285 | 151 | 702 | 54 | 907 |
| Income (loss) before income taxes | 3,758 | 879 | (801) | 3,836 | 6,504 | 4,721 | (3,873) | 7,352 | 5,366 | 1,797 | (2,500) | 4,663 |
| Income tax expense (benefit) | (11) | (21) | 480 | 448 | (134) | 1,195 | 515 | 1,576 | (14) | (1,719) | 1,073 | (660) |
| Net income (loss) | 3,769 | 900 | (1,281) | 3,388 | 6,638 | 3,526 | (4,388) | 5,776 | 5,380 | 3,516 | (3,573) | 5,323 |
| Net loss attributable to noncontrolling interests | — | 381 | — | 381 | — | 862 | — | 862 | — | 57 | — | 57 |
| Net income (loss) attributable to NEE | $ 3,769 | $ 1,281 | $ (1,281) | $ 3,769 | $ 6,638 | $ 4,388 | $ (4,388) | $ 6,638 | $ 5,380 | $ 3,573 | $ (3,573) | $ 5,380 |

(a) Represents primarily FPL and consolidating adjustments.

Condensed Consolidating Statements of Comprehensive Income

| | Year Ended December 31, 2019 | | | | Year Ended December 31, 2018 | | | | Year Ended December 31, 2017 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated |
| | (millions) | | | | | | | | | | | |
| Comprehensive income (loss) attributable to NEE | $ 3,789 | $ 1,340 | $ (1,340) | $ 3,789 | $ 6,667 | $ 4,434 | $ (4,434) | $ 6,667 | $ 5,561 | $ 3,710 | $ (3,710) | $ 5,561 |

(a) Represents primarily FPL and consolidating adjustments.

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Condensed Consolidating Balance Sheets

| | December 31, 2019 | | | | December 31, 2018 | | | |
|---|---|---|---|---|---|---|---|---|
| | **NEE (Guarantor)** | **NEECH** | **Other[a]** | **NEE Consolidated** | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated |
| | | | | (millions) | | | | |
| PROPERTY, PLANT AND EQUIPMENT | | | | | | | | |
| Electric plant in service and other property | **$ 170** | **$ 41,585** | **$ 65,423** | **$ 107,178** | $ 220 | $ 37,145 | $ 54,718 | $ 92,083 |
| Accumulated depreciation and amortization | **(111)** | **(9,473)** | **(15,584)** | **(25,168)** | (58) | (8,473) | (13,218) | (21,749) |
| Total property, plant and equipment - net | **59** | **32,112** | **49,839** | **82,010** | 162 | 28,672 | 41,500 | 70,334 |
| CURRENT ASSETS | | | | | | | | |
| Cash and cash equivalents | **1** | **515** | **84** | **600** | (1) | 525 | 114 | 638 |
| Receivables | **81** | **1,489** | **1,237** | **2,807** | 292 | 1,771 | 906 | 2,969 |
| Other | **16** | **2,633** | **1,352** | **4,001** | 5 | 1,425 | 1,356 | 2,786 |
| Total current assets | **98** | **4,637** | **2,673** | **7,408** | 296 | 3,721 | 2,376 | 6,393 |
| OTHER ASSETS | | | | | | | | |
| Investment in subsidiaries | **36,783** | **—** | **(36,783)** | **—** | 33,397 | — | (33,397) | — |
| Investment in equity method investees | **—** | **7,453** | **—** | **7,453** | — | 6,748 | — | 6,748 |
| Goodwill | 1 | 1,217 | 2,986 | 4,204 | 1 | 587 | 303 | 891 |
| Other | **404** | **6,899** | **9,313** | **16,616** | 937 | 5,890 | 12,509 | 19,336 |
| Total other assets | **37,188** | **15,569** | **(24,484)** | **28,273** | 34,335 | 13,225 | (20,585) | 26,975 |
| TOTAL ASSETS | **$ 37,345** | **$ 52,318** | **$ 28,028** | **$ 117,691** | $ 34,793 | $ 45,618 | $ 23,291 | $ 103,702 |
| CAPITALIZATION | | | | | | | | |
| Common shareholders' equity | **$ 37,005** | **$ 11,050** | **$ (11,050)** | **$ 37,005** | $ 34,144 | $ 7,917 | $ (7,917) | $ 34,144 |
| Noncontrolling interests | **—** | **4,355** | **—** | **4,355** | — | 3,269 | — | 3,269 |
| Redeemable noncontrolling interests | **—** | **487** | **—** | **487** | — | 468 | — | 468 |
| Long-term debt | **—** | **21,901** | **15,642** | **37,543** | — | 15,094 | 11,688 | 26,782 |
| Total capitalization | **37,005** | **37,793** | **4,592** | **79,390** | 34,144 | 26,748 | 3,771 | 64,663 |
| CURRENT LIABILITIES | | | | | | | | |
| Debt due within one year | **—** | **2,961** | **2,079** | **5,040** | — | 9,579 | 1,351 | 10,930 |
| Accounts payable | **3** | **2,755** | **873** | **3,631** | 32 | 1,730 | 624 | 2,386 |
| Other | **167** | **2,817** | **2,198** | **5,182** | 168 | 2,364 | 1,715 | 4,247 |
| Total current liabilities | **170** | **8,533** | **5,150** | **13,853** | 200 | 13,673 | 3,690 | 17,563 |
| OTHER LIABILITIES AND DEFERRED CREDITS | | | | | | | | |
| Asset retirement obligations | **—** | **1,072** | **2,385** | **3,457** | — | 988 | 2,147 | 3,135 |
| Deferred income taxes | **(410)** | **2,956** | **5,815** | **8,361** | (157) | 2,778 | 4,746 | 7,367 |
| Other | **580** | **1,964** | **10,086** | **12,630** | 606 | 1,431 | 8,937 | 10,974 |
| Total other liabilities and deferred credits | **170** | **5,992** | **18,286** | **24,448** | 449 | 5,197 | 15,830 | 21,476 |
| COMMITMENTS AND CONTINGENCIES | | | | | | | | |
| TOTAL CAPITALIZATION AND LIABILITIES | **$ 37,345** | **$ 52,318** | **$ 28,028** | **$ 117,691** | $ 34,793 | $ 45,618 | $ 23,291 | $ 103,702 |

(a) Represents primarily FPL and consolidating adjustments.

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Condensed Consolidating Statements of Cash Flows

| | Year Ended December 31, 2019 | | | | Year Ended December 31, 2018 | | | | Year Ended December 31, 2017 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **NEE (Guarantor)** | **NEECH** | **Other[a]** | **NEE Consolidated** | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated | NEE (Guarantor) | NEECH | Other[a] | NEE Consolidated |
| | (millions) | | | | | | | | | | | |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | **$ 2,769** | **$ 2,562** | **$ 2,824** | **$ 8,155** | $3,401 | $ 2,094 | $ 1,098 | $ 6,593 | $1,968 | $ 2,749 | $ 1,741 | $ 6,458 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | | | | | | | | | | |
| Capital expenditures, acquisitions, independent power and other investments and nuclear fuel purchases | **(7)** | **(6,509)** | **(10,946)** | **(17,462)** | (132) | (7,735) | (5,137) | (13,004) | — | (5,449) | (5,291) | (10,740) |
| Capital contributions from NEE | **(1,876)** | **—** | **1,876** | **—** | (6,270) | — | 6,270 | — | (92) | — | 92 | — |
| Proceeds from sale of the fiber-optic telecommunications business | **—** | **—** | **—** | **—** | — | — | — | — | — | 1,454 | — | 1,454 |
| Sale of independent power and other investments of NEER | **—** | **1,163** | **—** | **1,163** | — | 1,617 | — | 1,617 | — | 178 | — | 178 |
| Proceeds from sale or maturity of securities in special use funds and other investments | **—** | **1,279** | **2,729** | **4,008** | — | 1,178 | 2,232 | 3,410 | 9 | 1,221 | 1,977 | 3,207 |
| Purchases of securities in special use funds and other investments | **—** | **(1,306)** | **(2,854)** | **(4,160)** | — | (1,330) | (2,403) | (3,733) | — | (1,163) | (2,081) | (3,244) |
| Distributions from subsidiaries and equity method investees | **—** | **—** | **—** | **—** | 4,466 | 637 | (4,466) | 637 | — | 7 | — | 7 |
| Other - net | **103** | **150** | **21** | **274** | 12 | (130) | 241 | 123 | 7 | 195 | 18 | 220 |
| Net cash used in investing activities | **(1,780)** | **(5,223)** | **(9,174)** | **(16,177)** | (1,924) | (5,763) | (3,263) | (10,950) | (76) | (3,557) | (5,285) | (8,918) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | | | | | | | | | | |
| Issuances of long-term debt | **—** | **10,916** | **3,003** | **13,919** | — | 2,651 | 1,748 | 4,399 | — | 6,393 | 1,961 | 8,354 |
| Retirements of long-term debt | **—** | **(5,292)** | **(200)** | **(5,492)** | — | (1,512) | (1,590) | (3,102) | — | (5,907) | (873) | (6,780) |
| Proceeds from differential membership investors | **—** | **1,604** | **—** | **1,604** | — | 1,841 | — | 1,841 | — | 1,414 | — | 1,414 |
| Net change in commercial paper | **—** | **(651)** | **417** | **(234)** | — | 1,493 | (431) | 1,062 | — | — | 1,419 | 1,419 |
| Proceeds from other short-term debt | **—** | **—** | **200** | **200** | — | 5,665 | — | 5,665 | — | — | 450 | 450 |
| Repayments of other short-term debt | **—** | **(4,765)** | **—** | **(4,765)** | — | (205) | (250) | (455) | — | — | (2) | (2) |
| Payments to related parties under CSCS agreement – net | **—** | **(54)** | **—** | **(54)** | — | (21) | — | (21) | — | — | — | — |
| Issuances of common stock - net | **1,494** | **—** | **—** | **1,494** | 718 | — | — | 718 | 55 | — | — | 55 |
| Proceeds from issuance of NEP convertible preferred units - net | **—** | **—** | **—** | **—** | — | — | — | — | — | 548 | — | 548 |
| Dividends on common stock | **(2,408)** | **—** | **—** | **(2,408)** | (2,101) | — | — | (2,101) | (1,845) | — | — | (1,845) |
| Contributions from (dividends to) NEE | **—** | **1,479** | **(1,479)** | **—** | — | (7,272) | 7,272 | — | — | (633) | 633 | — |
| Other - net | **(73)** | **(271)** | **(47)** | **(391)** | (96) | (238) | (38) | (372) | (102) | (601) | (22) | (725) |
| Net cash provided by (used in) financing activities | **(987)** | **2,966** | **1,894** | **3,873** | (1,479) | 2,402 | 6,711 | 7,634 | (1,892) | 1,214 | 3,566 | 2,888 |
| Effects of currency translation on cash, cash equivalents and restricted cash | **—** | **4** | **—** | **4** | — | (7) | — | (7) | — | 26 | — | 26 |
| Net increase (decrease) in cash, cash equivalents and restricted cash | **2** | **309** | **(4,456)** | **(4,145)** | (2) | (1,274) | 4,546 | 3,270 | — | 432 | 22 | 454 |
| Cash, cash equivalents and restricted cash at beginning of year | **(1)** | **533** | **4,721** | **5,253** | 1 | 1,807 | 175 | 1,983 | 1 | 1,375 | 153 | 1,529 |
| Cash, cash equivalents and restricted cash at end of year | **$ 1** | **$ 842** | **$ 265** | **$ 1,108** | $ (1) | $ 533 | $ 4,721 | $ 5,253 | $ 1 | $ 1,807 | $ 175 | $ 1,983 |

(a) Represents primarily FPL and consolidating adjustments.

## 18. Quarterly Data (Unaudited)

Condensed consolidated quarterly financial information is as follows:

| | March 31[a] | June 30[a] | September 30[a] | December 31[a] |
|---|---|---|---|---|
| | (millions, except per share amounts) | | | |
| **NEE:** | | | | |
| 2019 | | | | |
| Operating revenues[b] | **$ 4,075** | **$ 4,970** | **$ 5,572** | **$ 4,588** |
| Operating income[b] | **$ 1,135** | **$ 1,747** | **$ 1,593** | **$ 878** |
| Net income[b] | **$ 606** | **$ 1,139** | **$ 798** | **$ 844** |
| Net income attributable to NEE[b] | **$ 680** | **$ 1,234** | **$ 879** | **$ 975** |
| Earnings per share attributable to NEE - basic[c] | **$ 1.42** | **$ 2.58** | **$ 1.82** | **$ 2.00** |
| Earnings per share attributable to NEE - assuming dilution[c] | **$ 1.41** | **$ 2.56** | **$ 1.81** | **$ 1.99** |
| Dividends per share | **$ 1.25** | **$ 1.25** | **$ 1.25** | **$ 1.25** |
| High-low common stock sales prices | **$195.55 - $168.66** | **$208.91 - $187.30** | **$233.45 - $201.06** | **$245.01 - $220.66** |
| 2018 | | | | |
| Operating revenues[b] | $ 3,857 | $ 4,063 | $ 4,416 | $ 4,390 |
| Operating income[b] | $ 1,059 | $ 1,146 | $ 968 | $ 1,107 |
| Net income[b][d] | $ 3,834 | $ 687 | $ 941 | $ 314 |
| Net income attributable to NEE[b][d] | $ 4,431 | $ 781 | $ 1,005 | $ 422 |
| Earnings per share attributable to NEE - basic[c][d] | $ 9.41 | $ 1.66 | $ 2.12 | $ 0.88 |
| Earnings per share attributable to NEE - assuming dilution[c][d] | $ 9.32 | $ 1.61 | $ 2.10 | $ 0.88 |
| Dividends per share | $ 1.11 | $ 1.11 | $ 1.11 | $ 1.11 |
| High-low common stock sales prices | $164.41 - $145.10 | $169.53 - $155.06 | $175.65 - $163.52 | $184.20 - $164.78 |
| **FPL:** | | | | |
| 2019 | | | | |
| Operating revenues[b] | **$ 2,618** | **$ 3,158** | **$ 3,491** | **$ 2,925** |
| Operating income[b] | **$ 857** | **$ 854** | **$ 973** | **$ 617** |
| Net income[b] | **$ 588** | **$ 663** | **$ 683** | **$ 400** |
| 2018 | | | | |
| Operating revenues[b] | $ 2,620 | $ 2,908 | $ 3,399 | $ 2,935 |
| Operating income[b] | $ 707 | $ 921 | $ 917 | $ 609 |
| Net income[b] | $ 484 | $ 626 | $ 654 | $ 407 |

(a) In the opinion of NEE and FPL management, all adjustments, which consist of normal recurring accruals necessary to present a fair statement of the amounts shown for such periods, have been made. Results of operations for an interim period generally will not give a true indication of results for the year.
(b) The sum of the quarterly amounts may not equal the total for the year due to rounding.
(c) The sum of the quarterly amounts may not equal the total for the year due to rounding and changes in weighted-average number of common shares outstanding.
(d) First quarter of 2018 includes gain on the deconsolidation of NEP (see Note 1 - NextEra Energy Partners, LP).

## Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

## Item 9A. Controls and Procedures

*Disclosure Controls and Procedures*

As of December 31, 2019, each of NEE and FPL had performed an evaluation, under the supervision and with the participation of its management, including NEE's and FPL's chief executive officer and chief financial officer, of the effectiveness of the design and operation of each company's disclosure controls and procedures (as defined in the Securities Exchange Act of 1934 Rules 13a-15 (e) and 15d-15(e)). Based upon that evaluation, the chief executive officer and the chief financial officer of each of NEE and FPL concluded that the company's disclosure controls and procedures were effective as of December 31, 2019.

*Internal Control Over Financial Reporting*

(a) Management's Annual Report on Internal Control Over Financial Reporting

See Item 8. Financial Statements and Supplementary Data.

(b) Attestation Report of the Independent Registered Public Accounting Firm

See Item 8. Financial Statements and Supplementary Data.

(c) Changes in Internal Control Over Financial Reporting

NEE and FPL are continuously seeking to improve the efficiency and effectiveness of their operations and of their internal controls. This results in refinements to processes throughout NEE and FPL. However, there has been no change in NEE's or FPL's internal control over financial reporting (as defined in the Securities Exchange Act of 1934 Rules 13a-15(f) and 15d-15(f)) that occurred during NEE's and FPL's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NEE's or FPL's internal control over financial reporting.

## Item 9B. Other Information

None

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item will be included under the headings "Business of the Annual Meeting," "Information About NextEra Energy and Management" and "Corporate Governance and Board Matters" in NEE's Proxy Statement which will be filed with the SEC in connection with the 2020 Annual Meeting of Shareholders (NEE's Proxy Statement) and is incorporated herein by reference, or is included in Item 1. Business - Information About Our Executive Officers.

NEE has adopted the NextEra Energy, Inc. Code of Ethics for Senior Executive and Financial Officers (the Senior Financial Executive Code), which is applicable to the chief executive officer, the chief financial officer, the chief accounting officer and other senior executive and financial officers. The Senior Financial Executive Code is available under Corporate Governance in the Investor Relations section of NEE's internet website at www.nexteraenergy.com. Any amendments or waivers of the Senior Financial Executive Code which are required to be disclosed to shareholders under SEC rules will be disclosed on the NEE website at the address listed above.

### Item 11. Executive Compensation

The information required by this item will be included in NEE's Proxy Statement under the headings "Executive Compensation" and "Corporate Governance and Board Matters" and is incorporated herein by reference.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item relating to security ownership of certain beneficial owners and management will be included in NEE's Proxy Statement under the heading "Information About NextEra Energy and Management" and is incorporated herein by reference.

**Securities Authorized For Issuance Under Equity Compensation Plans**

NEE's equity compensation plan information at December 31, 2019 is as follows:

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 4,011,354 [(a)] | $ 123.09 [(b)] | 6,414,488 [(c)] |
| Equity compensation plans not approved by security holders | — | — | — |
| Total | 4,011,354 | $ 123.09 | 6,414,488 |

(a) Includes an aggregate of 2,416,688 outstanding options, 1,422,352 unvested performance share awards (at maximum payout), 22,446 deferred fully vested performance shares and 117,936 deferred stock awards (including future reinvested dividends) under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan and former LTIP, and 31,932 fully vested shares deferred by directors under the NextEra Energy, Inc. 2007 Non-Employee Directors Stock Plan and its predecessor, the FPL Group, Inc. Amended and Restated Non-Employee Directors Stock Plan.

(b) Relates to outstanding options only.

(c) Includes 5,939,880 shares under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan and 474,608 shares under the NextEra Energy, Inc. 2017 Non-Employee Directors Stock Plan.

### Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item, to the extent applicable, will be included in NEE's Proxy Statement under the heading "Corporate Governance and Board Matters" and is incorporated herein by reference.

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## Item 14. Principal Accounting Fees and Services

**NEE** - The information required by this item will be included in NEE's Proxy Statement under the heading "Audit-Related Matters" and is incorporated herein by reference.

**FPL** - The following table presents fees billed for professional services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, Deloitte & Touche) for the fiscal years ended December 31, 2019 and 2018. The amounts presented below reflect allocations from NEE for FPL's portion of the fees, as well as amounts billed directly to FPL.

| | 2019 | 2018 |
|---|---|---|
| Audit fees[(a)] | **$ 3,621,000** | $ 3,895,000 |
| Audit-related fees[(b)] | **380,000** | 84,000 |
| Tax fees[(c)] | **2,097,000** | 256,000 |
| All other fees[(d)] | **15,000** | 7,000 |
| Total | **$ 6,113,000** | $ 4,242,000 |

(a) Audit fees consist of fees billed for professional services rendered for the audit of FPL's and NEE's annual consolidated financial statements for the fiscal year, the reviews of the financial statements included in FPL's and NEE's Quarterly Reports on Form 10-Q during the fiscal year and the audit of the effectiveness of internal control over financial reporting, comfort letters, and consents.

(b) Audit-related fees consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of FPL's and NEE's consolidated financial statements and are not reported under audit fees. These fees primarily relate to audits of subsidiary financial statements and attestation services.

(c) Tax fees consist of fees billed for professional services rendered for tax compliance, tax advice and tax planning. In 2019 and 2018, approximately $2,069,000 and $36,000, respectively, was paid related to tax compliance services. In 2019, these fees primarily related to research and development tax credit compliance services. All other tax fees in 2019 and in 2018 related to tax advice and planning services.

(d) All other fees consist of fees for products and services other than the services reported under the other named categories. In 2019 and 2018, these fees related to training.

In accordance with the requirements of the Sarbanes-Oxley Act of 2002, the Audit Committee Charter and the Audit Committee's pre-approval policy for services provided by the independent registered public accounting firm, all services performed by Deloitte & Touche are approved in advance by the Audit Committee, except for audits of certain trust funds where the fees are paid by the trust. Audit and audit-related services specifically identified in an appendix to the pre-approval policy are pre-approved by the Audit Committee each year. This pre-approval allows management to request the specified audit and audit-related services on an as-needed basis during the year, provided any such services are reviewed with the Audit Committee at its next regularly scheduled meeting. Any audit or audit-related service for which the fee is expected to exceed $250,000, or that involves a service not listed on the pre-approval list, must be specifically approved by the Audit Committee prior to commencement of such service. In addition, the Audit Committee approves all services other than audit and audit-related services performed by Deloitte & Touche in advance of the commencement of such work. The Audit Committee has delegated to the Chair of the committee the right to approve audit, audit-related, tax and other services, within certain limitations, between meetings of the Audit Committee, provided any such decision is presented to the Audit Committee at its next regularly scheduled meeting. At each Audit Committee meeting (other than meetings held to review earnings materials), the Audit Committee reviews a schedule of services for which Deloitte & Touche has been engaged since the prior Audit Committee meeting under existing pre-approvals and the estimated fees for those services. In 2019 and 2018, none of the amounts presented above represent services provided to NEE or FPL by Deloitte & Touche that were approved by the Audit Committee after services were rendered pursuant to Rule 2-01(c)(7)(i)(C) of Regulation S-X (which provides for a waiver of the otherwise applicable pre-approval requirement if certain conditions are met).

## PART IV

### Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements


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2. Financial Statement Schedules - Schedules are omitted as not applicable or not required.

3. Exhibits (including those incorporated by reference)

Certain exhibits listed below refer to "FPL Group" and "FPL Group Capital," and were effective prior to the change of the name FPL Group, Inc. to NextEra Energy, Inc., and of the name FPL Group Capital Inc to NextEra Energy Capital Holdings, Inc., during 2010.

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *2(a) | Stock Purchase Agreement by and among The Southern Company, 700 Universe, LLC and NextEra Energy, Inc. dated as of May 20, 2018 (filed as Exhibit 2(a) to Form 8-K dated May 23, 2018, File No. 1-8841) | x | |
| *2(b) | Stock Purchase Agreement by and among NUI Corporation, Southern Company Gas, 700 Universe, LLC and NextEra Energy, Inc. dated as of May 20, 2018 (filed as Exhibit 2(b) to Form 8-K dated May 23, 2018, File No. 1-8841) | x | |
| *3(i)a | Restated Articles of Incorporation of NextEra Energy, Inc. (filed as Exhibit 3(i)(b) to Form 8-K dated May 21, 2015, File No. 1-8841) | x | |
| *3(i)b | Restated Articles of Incorporation of Florida Power & Light Company (filed as Exhibit 3 (i)b to Form 10-K for the year ended December 31, 2010, File No. 2-27612) | | x |
| *3(ii)a | Amended and Restated Bylaws of NextEra Energy, Inc., effective October 14, 2016 (filed as Exhibit 3(ii)(b) to Form 8-K dated October 14, 2016, File No. 1-8841) | x | |
| *3(ii)b | Amended and Restated Bylaws of Florida Power & Light Company, Inc., as amended through October 17, 2008 (filed as Exhibit 3(ii)b to Form 10-Q for the quarter ended September 30, 2008, File No. 2-27612) | | x |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *4(a) | Mortgage and Deed of Trust dated as of January 1, 1944, as amended, between Florida Power & Light Company and Deutsche Bank Trust Company Americas, Trustee (filed as Exhibit B-3, File No. 2-4845; Exhibit 7(a), File No. 2-7126; Exhibit 7(a), File No. 2-7523; Exhibit 7(a), File No. 2-7990; Exhibit 7(a), File No. 2-9217; Exhibit 4(a)-5, File No. 2-10093; Exhibit 4(c), File No. 2-11491; Exhibit 4(b)-1, File No. 2-12900; Exhibit 4(b)-1, File No. 2-13255; Exhibit 4(b)-1, File No. 2-13705; Exhibit 4(b)-1, File No. 2-13925; Exhibit 4(b)-1, File No. 2-15088; Exhibit 4(b)-1, File No. 2-15677; Exhibit 4(b)-1, File No. 2-20501; Exhibit 4(b)-1, File No. 2-22104; Exhibit 2(c), File No. 2-23142; Exhibit 2(c), File No. 2-24195; Exhibit 4(b)-1, File No. 2-25677; Exhibit 2(c), File No. 2-27612; Exhibit 2(c), File No. 2-29001; Exhibit 2(c), File No. 2-30542; Exhibit 2(c), File No. 2-33038; Exhibit 2(c), File No. 2-37679; Exhibit 2(c), File No. 2-39006; Exhibit 2(c), File No. 2-41312; Exhibit 2(c), File No. 2-44234; Exhibit 2(c), File No. 2-46502; Exhibit 2(c), File No. 2-48679; Exhibit 2(c), File No. 2-49726; Exhibit 2(c), File No. 2-50712; Exhibit 2(c), File No. 2-52826; Exhibit 2(c), File No. 2-53272; Exhibit 2(c), File No. 2-54242; Exhibit 2(c), File No. 2-56228; Exhibits 2(c) and 2(d), File No. 2-60413; Exhibits 2(c) and 2(d), File No. 2-65701; Exhibit 2(c), File No. 2-66524; Exhibit 2(c), File No. 2-67239; Exhibit 4(c), File No. 2-69716; Exhibit 4(c), File No. 2-70767; Exhibit 4(b), File No. 2-71542; Exhibit 4(b), File No. 2-73799; Exhibits 4(c), 4(d) and 4(e), File No. 2-75762; Exhibit 4(c), File No. 2-77629; Exhibit 4(c), File No. 2-79557; Exhibit 99(a) to Post-Effective Amendment No. 5 to Form S-8, File No. 33-18669; Exhibit 99(a) to Post-Effective Amendment No. 1 to Form S-3, File No. 33-46076; Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 1995, File No. 1-3545; Exhibit 4(a) to Form 10-Q for the quarter ended March 31, 1996, File No. 1-3545; Exhibit 4(o), File No. 333-102169; Exhibit 4(k) to Post-Effective Amendment No. 1 to Form S-3, File No. 333-102172; Exhibit 4(l) to Post-Effective Amendment No. 2 to Form S-3, File No. 333-102172; Exhibit 4(m) to Post-Effective Amendment No. 3 to Form S-3, File No. 333-102172; Exhibit 4(f) to Amendment No. 1 to Form S-3, File No. 333-125275; Exhibit 4(y) to Post-Effective Amendment No. 2 to Form S-3, File Nos. 333-116300, 333-116300-01 and 333-116300-02; Exhibit 4(z) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-116300, 333-116300-01 and 333-116300-02; Exhibit 4(b) to Form 10-Q for the quarter ended March 31, 2006, File No. 2-27612; Exhibit 4(a) to Form 8-K dated April 17, 2007, File No. 2-27612; Exhibit 4 to Form 8-K dated January 16, 2008, File No. 2-27612; Exhibit 4(a) to Form 8-K dated March 17, 2009, File No. 2-27612; Exhibit 4 to Form 8-K dated February 9, 2010, File No. 2-27612; Exhibit 4 to Form 8-K dated December 9, 2010, File No. 2-27612; Exhibit 4(a) to Form 8-K dated June 10, 2011, File No. 2-27612; Exhibit 4 to Form 8-K dated December 13, 2011, File No. 2-27612; Exhibit 4 to Form 8-K dated May 15, 2012, File No. 2-27612; Exhibit 4 to Form 8-K dated December 20, 2012, File No. 2-27612; Exhibit 4 to Form 8-K dated June 5, 2013, File No. 2-27612; Exhibit 4 to Form 8-K dated May 15, 2014, File No. 2-27612; Exhibit 4 to Form 8-K dated September 10, 2014, File No. 2-27612; Exhibit 4 to Form 8-K dated November 19, 2015, File No. 2-27612; Exhibit 4 (b) to Form 10-K dated December 31, 2017, File No. 2-27612; Exhibit 4(a) to Form 10-Q dated March 31, 2018, File No. 2-27612; Exhibit 4(j), File No. 333-226056, 333-226056-01 and 333-226056-02; Exhibit 4(k), File No. 333-226056, 333-226056-01 and 333-226056-02; Exhibit 4(a) to Form 10-Q dated March 31, 2019, File No. 2-27612; and Exhibit 4(f) to Form 10-Q dated September 30, 2019, File No. 2-27612) | x | x |
| *4(b) | Indenture (For Unsecured Debt Securities), dated as of November 1, 2017, between Florida Power & Light Company and The Bank of New York Mellon (as Trustee) (filed as Exhibit 4(a) to Form 8-K dated November 6, 2017, File No. 2-27612) | x | x |
| *4(c) | Officer's Certificate of Florida Power & Light Company, dated June 15, 2018, creating the Floating Rate Notes, Series due June 15, 2068 (filed as Exhibit 4 to Form 8-K dated June 15, 2018, File No. 2-27612) | x | x |
| *4(d) | Officer's Certificate of Florida Power & Light Company, dated November 14, 2018, creating the Floating Rate Notes, Series due November 14, 2068 (filed as Exhibit 4 to Form 8-K dated November 14, 2018, File No. 2-27612) | x | x |
| *4(e) | Officer's Certificate of Florida Power & Light Company, dated March 27, 2019, creating the Floating Rate Notes, Series due March 27, 2069 (filed as Exhibit 4(b) to Form 8-K dated March 27, 2019, File No. 2-27612) | x | x |
| *4(f) | Officer's Certificate of Florida Power & Light Company, dated May 7, 2019, creating the Floating Rate Notes, Series due May 6, 2022 (filed as Exhibit 4 to Form 8-K dated May 7, 2019, File No. 2-27612) | x | x |

| Exhibit Number | Description | NEE | FPL |
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| *4(g) | Indenture (For Unsecured Debt Securities), dated as of June 1, 1999, between FPL Group Capital Inc and The Bank of New York Mellon, as Trustee (filed as Exhibit 4(a) to Form 8-K dated July 16, 1999, File No. 1-8841) | x | x |
| *4(h) | First Supplemental Indenture to Indenture (For Unsecured Debt Securities) dated as of June 1, 1999, dated as of September 21, 2012, between NextEra Energy Capital Holdings, Inc. and The Bank of New York Mellon, as Trustee (filed as Exhibit 4(e) to Form 10-Q for the quarter ended September 30, 2012, File No. 1-8841) | x | x |
| *4(i) | Guarantee Agreement, dated as of June 1, 1999, between FPL Group, Inc. (as Guarantor) and The Bank of New York Mellon (as Guarantee Trustee) (filed as Exhibit 4(b) to Form 8-K dated July 16, 1999, File No. 1-8841) | x | |
| *4(j) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated June 10, 2011, creating the 4.50% Debentures, Series due June 1, 2021 (filed as Exhibit 4(b) to Form 8-K dated June 10, 2011, File No. 1-8841) | x | |
| *4(k) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. dated June 6, 2013, creating the 3.625% Debentures, Series due June 15, 2023 (filed as Exhibit 4 to Form 8-K dated June 6, 2013, File No. 1-8841) | x | |
| *4(l) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated August 27, 2015, creating the 2.80% Debentures, Series due August 27, 2020 (filed as Exhibit 4(c) to Form 10-Q for the quarter ended September 30, 2015, File No. 1-8841) | x | |
| *4(m) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated September 16, 2015, creating the Series H Debentures due September 1, 2020 (filed as Exhibit 4(c) to Form 8-K dated September 16, 2015, File No. 1-8841) | x | |
| *4(n) | Letter, dated August 9, 2018, from NextEra Energy Capital Holdings, Inc. to The Bank of New York Mellon, as trustee, setting forth certain terms of the Series H Debentures due September 1, 2020, effective August 9, 2018 (filed as Exhibit 4(b) to Form 8-K dated August 9, 2018, File No. 1-8841) | x | |
| *4(o) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated August 8, 2016, creating the Series I Debentures due September 1, 2021 (filed as Exhibit 4(c) to Form 8-K dated August 8, 2016, File No. 1-8841) | x | |
| *4(p) | Letter, dated August 8, 2019, from NextEra Energy Capital Holdings, Inc. to The Bank of New York Mellon, as trustee, setting forth certain terms of the Series I Debentures due September 1, 2021 effective August 8, 2019 (filed as Exhibit 4(b) to Form 8-K dated August 8, 2019, File No. 1-8841) | x | |
| *4(q) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated April 28, 2017, creating the 3.55% Debentures, Series due May 1, 2027 (filed as Exhibit 4 to Form 8-K dated April 28, 2017, File No. 1-8841) | x | |
| *4(r) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated December 14, 2017, creating the 2.80% Debentures, Series due January 15, 2023 (filed as Exhibit 4 to Form 8-K dated December 14, 2017, File No. 1-8841) | x | |
| *4(s) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated May 4, 2018, creating the Floating Rate Debentures, Series due May 4, 2021 (filed as Exhibit 4 to Form 8-K dated May 4, 2018, File No. 1-8841) | x | |
| *4(t) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated August 28, 2018, creating the Floating Rate Debentures, Series due August 28, 2021 (filed as Exhibit 4 (b) to Form 8-K dated August 28, 2018, File No. 1-8841) | x | |
| *4(u) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated February 27, 2019, creating the 3.20% Debentures, Series due February 25, 2022 (filed as Exhibit 4(b) to Form 8-K dated February 27, 2019, File No. 1-8841) | x | |
| *4(v) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated February 27, 2019, creating the Floating Rate Debentures, Series due February 25, 2022 (filed as Exhibit 4 (a) to Form 8-K dated February 27, 2019, File No. 1-8841) | x | |
| *4(w) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated March 6, 2019, creating the 3.30% Debentures, Series due August 15, 2022 (filed as Exhibit 4(a) to Form 8-K dated March 6, 2019, File No. 1-8841) | x | |
| *4(x) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated March 27, 2019, creating the Floating Rate Debentures, Series due September 28, 2020 (filed as Exhibit 4(a) to Form 8-K dated March 27, 2019, File No. 1-8841) | x | |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *4(y) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated April 4, 2019, creating the 2.90% Debentures, Series due April 1, 2022 (filed as Exhibit 4(a) to Form 8-K dated April 4, 2019, File No. 1-8841) | x | |
| *4(z) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated April 4, 2019, creating the 3.15% Debentures, Series due April 1, 2024 (filed as Exhibit 4(b) to Form 8-K dated April 4, 2019, File No. 1-8841) | x | |
| *4(aa) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated April 4, 2019, creating the 3.25% Debentures, Series due April 1, 2026 (filed as Exhibit 4(c) to Form 8-K dated April 4, 2019, File No. 1-8841) | x | |
| *4(bb) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated April 4, 2019, creating the 3.50% Debentures, Series due April 1, 2029 (filed as Exhibit 4(d) to Form 8-K dated April 4, 2019, File No. 1-8841) | x | |
| *4(cc) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated September 9, 2019, creating the Series J Debentures due September 1, 2024 (filed as Exhibit 4(e) to Form 10-Q dated September 30, 2019, File No. 1-8841) | x | |
| *4(dd) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated October 3, 2019, creating the 2.75% Debentures, Series due November 1, 2029 (filed as Exhibit 4 to Form 8-K dated October 3, 2019, File No. 1-8841) | x | |
| *4(ee) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated October 7, 2019, creating the 1.95% Debentures, Series due September 1, 2022 (filed as Exhibit 4 to Form 8-K dated October 7, 2019, File No. 1-8841) | x | |
| *4(ff) | Indenture (For Unsecured Subordinated Debt Securities relating to Trust Securities), dated as of March 1, 2004, among FPL Group Capital Inc, FPL Group, Inc. (as Guarantor) and The Bank of New York Mellon (as Trustee) (filed as Exhibit 4(au) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03) | x | |
| *4(gg) | Indenture (For Unsecured Subordinated Debt Securities), dated as of September 1, 2006, among FPL Group Capital Inc, FPL Group, Inc. (as Guarantor) and The Bank of New York Mellon (as Trustee) (filed as Exhibit 4(a) to Form 8-K dated September 19, 2006, File No. 1-8841) | x | |
| *4(hh) | First Supplemental Indenture to Indenture (For Unsecured Subordinated Debt Securities) dated as of September 1, 2006, dated as of November 19, 2012, between NextEra Energy Capital Holdings, Inc., NextEra Energy, Inc. as Guarantor, and The Bank of New York Mellon, as Trustee (filed as Exhibit 2 to Form 8-A dated January 16, 2013, File No. 1-33028) | x | |
| *4(ii) | Officer's Certificate of FPL Group Capital Inc and FPL Group, Inc., dated September 19, 2006, creating the Series B Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4(c) to Form 8-K dated September 19, 2006, File No. 1-8841) | x | |
| *4(jj) | Replacement Capital Covenant, dated September 19, 2006, by FPL Group Capital Inc and FPL Group, Inc. relating to FPL Group Capital Inc's Series B Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4(d) to Form 8-K dated September 19, 2006, File No. 1-8841) | x | |
| *4(kk) | Amendment, dated November 9, 2016, to the Replacement Capital Covenant, dated September 19, 2006, by NextEra Energy Capital Holdings, Inc. (formerly known as FPL Group Capital Holdings Inc) and NextEra Energy, Inc. (formerly known as FPL Group, Inc.), relating to FPL Group Capital Inc's Series B Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4 (cc) to Form 10-K for the year ended December 31, 2016, File No. 1-8841) | x | |
| *4(ll) | Officer's Certificate of FPL Group Capital Inc and FPL Group, Inc., dated June 12, 2007, creating the Series C Junior Subordinated Debentures due 2067 (filed as Exhibit 4(a) to Form 8-K dated June 12, 2007, File No. 1-8841) | x | |
| *4(mm) | Replacement Capital Covenant, dated June 12, 2007, by FPL Group Capital Inc and FPL Group, Inc. relating to FPL Group Capital Inc's Series C Junior Subordinated Debentures due 2067 (filed as Exhibit 4(b) to Form 8-K dated June 12, 2007, File No. 1-8841) | x | |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *4(nn) | Amendment, dated November 9, 2016, to the Replacement Capital Covenant, dated June 12, 2007 by NextEra Energy Capital Holdings, Inc. (formerly known as FPL Group Capital Holdings Inc) and NextEra Energy, Inc. (formerly known as FPL Group, Inc.), relating to FPL Group Capital Inc's Series C Junior Subordinated Debentures due 2067 (filed as Exhibit 4(hh) to Form 10-K for the year ended December 31, 2016, File No. 1-8841) | x | |
| *4(oo) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. and NextEra Energy, Inc., dated November 19, 2012, creating the Series I Junior Subordinated Debentures due November 15, 2072 (filed as Exhibit 4 to Form 8-K dated November 19, 2012, File No. 1-8841) | x | |
| *4(pp) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. and NextEra Energy, Inc., dated January 18, 2013, creating the Series J Junior Subordinated Debentures due January 15, 2073 (filed as Exhibit 4 to Form 8-K dated January 18, 2013, File No. 1-8841) | x | |
| *4(qq) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. and NextEra Energy, Inc., dated June 7, 2016, creating the Series K Junior Subordinated Debentures due June 1, 2076 (filed as Exhibit 4 to Form 8-K dated June 7, 2016, File No. 1-8841) | x | |
| *4(rr) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated September 29, 2017, creating the Series L Junior Subordinated Debentures due September 29, 2057 (filed as Exhibit 4(c) to Form 8-K dated September 29, 2017, File No. 1-8841) | x | |
| *4(ss) | Officer's Certificate of NextEra Energy Capital Holdings, Inc., dated November 2, 2017, creating the Series M Junior Subordinated Debentures due December 1, 2077 (filed as Exhibit 4(a) to Form 8-K dated November 2, 2017, File No. 1-8841) | x | |
| *4(tt) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. and NextEra Energy, Inc., dated March 15, 2019, creating the Series N Junior Subordinated Debentures due March 1, 2079 (filed as Exhibit 4 to Form 8-K dated March 15, 2019, File No. 1-8841) | x | |
| *4(uu) | Officer's Certificate of NextEra Energy Capital Holdings, Inc. and NextEra Energy, Inc., dated April 4, 2019, creating the Series O Junior Subordinated Debentures due May 1, 2079 (filed as Exhibit 4(e) to Form 8-K dated April 4, 2019, File No. 1-8841) | x | |
| *4(vv) | Indenture (For Securing Senior Secured Bonds, Series A), dated May 22, 2007, between FPL Recovery Funding LLC (as Issuer) and The Bank of New York Mellon (as Trustee and Securities Intermediary) (filed as Exhibit 4.1 to Form 8-K dated May 22, 2007 and filed June 1, 2007, File No. 333-141357) | | x |
| *4(ww) | Purchase Contract Agreement, dated as of September 1, 2019, between NextEra Energy, Inc. and The Bank of New York Mellon, as Purchase Contract Agent (filed as Exhibit 4 (c) to Form 10-Q for the quarter ended September 30, 2019, File No. 1-8841) | x | |
| *4(xx) | Pledge Agreement, dated as of September 1, 2019, between NextEra Energy, Inc., Deutsche Bank Trust Company Americas, as Collateral Agent, Custodial Agent and Securities Intermediary, and The Bank of New York Mellon, as Purchase Contract Agent (filed as Exhibit 4(d) to Form 10-Q for the quarter ended September 30, 2019, File No. 1-8841) | x | |
| *4(yy) | Senior Note Indenture dated as of January 1, 1998, between Gulf Power Company and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto (filed as Exhibit 4.1 to Form 8-K dated June 17, 1998, File No. 0-2429; Exhibit 4.2 to Form 8-K dated April 6, 2010, File No. 1-31737; Exhibit 4.2 to Form 8-K dated September 9, 2010, File No. 1-31737; Exhibit 4.2 to Form 8-K dated May 15, 2012, File No. 1-31737; Exhibit 4.2 to Form 8-K dated June 10, 2013, File No. 1-31737; Exhibit 4.2 to Form 8-K dated September 16, 2014, File No. 1-31737; and Exhibit 4.2 to Form 8-K dated May 15, 2017, File No. 1-31737) | x | |
| 4(zz) | Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 | x | |
| *10(a) | FPL Group, Inc. Supplemental Executive Retirement Plan, amended and restated effective April 1, 1997 (SERP) (filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 1999, File No. 1-8841) | x | x |
| *10(b) | FPL Group, Inc. Supplemental Executive Retirement Plan, amended and restated effective January 1, 2005 (Restated SERP) (filed as Exhibit 10(b) to Form 8-K dated December 12, 2008, File No. 1-8841) | x | x |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *10(c) | Amendment Number 1 to the Restated SERP changing name to NextEra Energy, Inc. Supplemental Executive Retirement Plan (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, File No. 1-8841) | x | x |
| *10(d) | Appendix A1 (revised as of March 16, 2016) to the NextEra Energy, Inc. Supplemental Executive Retirement Plan (filed as Exhibit 10(d) to Form 10-K dated December 31, 2017, File No. 1-8841) | x | x |
| *10(e) | Appendix A2 (revised as of October 1, 2017) to the NextEra Energy, Inc. Supplemental Executive Retirement Plan (filed as Exhibit 10(e) to Form 10-K dated December 31, 2017, File No. 1-8841) | x | x |
| *10(f) | Supplement to the Restated SERP relating to a special credit to certain executive officers and other officers effective February 15, 2008 (filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 2007, File No. 1-8841) | x | x |
| *10(g) | Supplement to the Restated SERP effective February 15, 2008 as it applies to Armando Pimentel, Jr. (filed as Exhibit 10(i) to Form 10-K for the year ended December 31, 2007, File No. 1-8841) | x | x |
| *10(h) | Supplement to the SERP effective December 14, 2007 as it applies to Manoochehr K. Nazar (filed as Exhibit 10(j) to Form 10-K for the year ended December 31, 2009, File No. 1-8841) | x | x |
| *10(i) | NextEra Energy, Inc. (formerly known as FPL Group, Inc.) Amended and Restated Long-Term Incentive Plan, most recently amended and restated on May 22, 2009 (filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2009, File No. 1-8841) | x | x |
| *10(j) | NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 10(c) to Form 8-K dated March 16, 2012, File No. 1-8841) | x | x |
| *10(k) | Form of Performance Share Award Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(l) | Form of Performance Share Award Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(m) | Form of Performance Share Award Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2018, File No. 1-8841) | x | x |
| *10(n) | Form of Restricted Stock Award Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(e) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(o) | Form of Restricted Stock Award Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2018, File No. 1-8841) | x | x |
| *10(p) | Form of FPL Group, Inc. Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement effective February 15, 2008 (filed as Exhibit 10(b) to Form 8-K dated February 15, 2008, File No. 1-8841) | x | x |
| *10(q) | Form of FPL Group, Inc. Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement effective February 13, 2009 (filed as Exhibit 10(u) to Form 10-K for the year ended December 31, 2008, File No. 1-8841) | x | x |
| *10(r) | Form of FPL Group, Inc. Amended and Restated Long-Term Incentive Plan - Non-Qualified Stock Option Agreement effective February 12, 2010 (filed as Exhibit 10(bb) to Form 10-K for the year December 31, 2009, File No. 1-8841) | x | x |
| *10(s) | Form of NextEra Energy, Inc. Amended and Restated Long-Term Incentive Plan - Non-Qualified Stock Option Agreement effective February 18, 2011 (filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2011, File No. 1-8841) | x | x |
| *10(t) | Form of Non-Qualified Stock Option Award Agreement under the NextEra Energy, Inc. 2011 Long Term Incentive Plan (filed as Exhibit 10(b) to Form 8-K dated October 13, 2011, File No. 1-8841) | x | x |
| *10(u) | Form of Non-Qualified Stock Option Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(f) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *10(v) | Form of Non-Qualified Stock Option Agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(g) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(w) | Form of Non-Qualified Stock Option agreement under the NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan for certain executive officers (filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2018, File No. 1-8841) | x | x |
| *10(x) | Form of FPL Group, Inc. Amended and Restated Long-Term Incentive Plan Amended and Restated Deferred Stock Award Agreement effective February 12, 2010 between FPL Group, Inc. and James L. Robo (filed as Exhibit 10(dd) to Form 10-K for the year ended December 31, 2009, File No. 1-8841) | x | x |
| *10(y) | Form of Deferred Stock Award Agreement under NextEra Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 10(a) to Form 8-K dated March 16, 2012, File No. 1-8841) | x | x |
| *10(z) | NextEra Energy, Inc. 2013 Executive Annual Incentive Plan (filed as Exhibit 10(c) to Form 8-K dated October 11, 2012, File No. 1-8841) | x | x |
| *10(aa) | NextEra Energy, Inc. Deferred Compensation Plan effective January 1, 2005 as amended and restated through February 11, 2016 (filed as Exhibit 10(h) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(bb) | FPL Group, Inc. Deferred Compensation Plan, amended and restated effective January 1, 2003 (filed as Exhibit 10(k) to Form 10-K for the year ended December 31, 2002, File No. 1-8841) | x | x |
| *10(cc) | FPL Group, Inc. Executive Long-Term Disability Plan effective January 1, 1995 (filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 1995, File No. 1-8841) | x | x |
| *10(dd) | FPL Group, Inc. Amended and Restated Non-Employee Directors Stock Plan, as amended and restated October 13, 2006 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2006, File No. 1-8841) | x | |
| *10(ee) | FPL Group, Inc. 2007 Non-Employee Directors Stock Plan (filed as Exhibit 99 to Form S-8, File No. 333-143739) | x | |
| *10(ff) | NextEra Energy, Inc. 2017 Non-Employee Directors Stock Plan, as amended and restated as of May 18, 2017 (filed as Exhibit 10 to Form 10-Q for the quarter ended June 30, 2017, File No. 1-8841) | x | |
| *10(gg) | NextEra Energy, Inc. Non-Employee Director Compensation Summary effective January 1, 2019 (filed as Exhibit 10(hh) to Form 10-K for the year ended December 31, 2018, File No. 1-8841) | x | |
| 10(hh) | NextEra Energy, Inc. Non-Employee Director Compensation Summary effective January 1, 2020 | x | |
| *10(ii) | Form of Amended and Restated Executive Retention Employment Agreement effective December 10, 2009 between FPL Group, Inc. and each of James L. Robo, Armando Pimentel, Jr., and Charles E. Sieving (filed as Exhibit 10(nn) to Form 10-K for the year ended December 31, 2009, File No. 1-8841) | x | x |
| *10(jj) | Executive Retention Employment Agreement between FPL Group, Inc. and Joseph T. Kelliher dated as of May 21, 2009 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2009, File No. 1-8841) | x | x |
| *10(kk) | Executive Retention Employment Agreement between FPL Group, Inc. and Manoochehr K. Nazar dated as of January 1, 2010 (filed as Exhibit 10(rr) to Form 10-K for the year ended December 31, 2009, File No. 1-8841) | x | x |
| *10(ll) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Eric E. Silagy dated as of May 2, 2012 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, File No. 1-8841) | x | x |
| *10(mm) | Executive Retention Employment Agreement between NextEra Energy, Inc. and William L. Yeager dated as of January 1, 2013 (filed as Exhibit 10(ccc) to Form 10-K for the year ended December 31, 2012, File No. 1-8841) | x | x |

| Exhibit Number | Description | NEE | FPL |
|---|---|---|---|
| *10(nn) | Form of 2012 409AAmendment to NextEra Energy, Inc. Executive Retention Employment Agreement effective October 11, 2012 between NextEra Energy, Inc. and each of James L. Robo, Armando Pimentel, Jr., Eric E. Silagy, Joseph T. Kelliher, Manoochehr K. Nazar and Charles E. Sieving (filed as Exhibit 10(ddd) to Form 10-K for the year ended December 31, 2012, File No. 1-8841) | x | x |
| *10(oo) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Deborah H. Caplan dated as of April 23, 2013 (filed as Exhibit 10(e) to Form 10-Q for the quarter ended June 30, 2013, File No. 1-8841) | x | x |
| *10(pp) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Miguel Arechabala dated as of January 1, 2014 (filed as Exhibit 10(bbb) to Form 10-K for the year ended December 31, 2013, File No. 1-8841) | x | x |
| *10(qq) | Executive Retention Employment Agreement between NextEra Energy, Inc. and John W. Ketchum dated as of March 4, 2016 (filed as Exhibit 10(i) to Form 10-Q for the quarter ended March 31, 2016, File No. 1-8841) | x | x |
| *10(rr) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Rebecca J. Kujawa dated as of March 1, 2019 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2019, File No. 1-8841) | x | x |
| 10(ss) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Donald Moul dated as of January 1, 2020 | x | x |
| 10(tt) | Executive Retention Employment Agreement between NextEra Energy, Inc. and Ronald Reagan dated as of January 1, 2020 | x | x |
| *10(uu) | NextEra Energy, Inc. Executive Severance Benefit Plan effective February 26, 2013 (filed as Exhibit 10(eee) to Form 10-K for the year ended December 31, 2012, File No. 1-8841) | x | x |
| *10(vv) | Guarantee Agreement between FPL Group, Inc. and FPL Group Capital Inc, dated as of October 14, 1998 (filed as Exhibit 10(y) to Form 10-K for the year ended December 31, 2001, File No. 1-8841) | x | |
| *10(ww) | NextEra Energy Partners, LP 2014 Long-Term Incentive Plan (filed as Exhibit 10.8 to Form 8-K dated July 1, 2014, File No. 1-36518) | x | |
| *10(xx) | Form of Restricted Unit Award Agreement under the NextEra Energy Partners, LP 2014 Long-Term Incentive Plan (filed as Exhibit 10.17 to Form 10-K for the year ended December 31, 2017, File No. 1-36518) | x | |
| 21 | Subsidiaries of NextEra Energy, Inc. | x | |
| 23 | Consent of Independent Registered Public Accounting Firm | x | x |
| 31(a) | Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of NextEra Energy, Inc. | x | |
| 31(b) | Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer of NextEra Energy, Inc. | x | |
| 31(c) | Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of Florida Power & Light Company | | x |
| 31(d) | Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer of Florida Power & Light Company | | x |
| 32(a) | Section 1350 Certification of NextEra Energy, Inc. | x | |
| 32(b) | Section 1350 Certification of Florida Power & Light Company | | x |
| 101.INS | XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document | x | x |
| 101.SCH | Inline XBRL Schema Document | x | x |
| 101.PRE | Inline XBRL Presentation Linkbase Document | x | x |
| 101.CAL | Inline XBRL Calculation Linkbase Document | x | x |
| 101.LAB | Inline XBRL Label Linkbase Document | x | x |
| 101.DEF | Inline XBRL Definition Linkbase Document | x | x |
| 104 | Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101) | x | x |

* Incorporated herein by reference

NEE and FPL agree to furnish to the SEC upon request any instrument with respect to long-term debt that NEE and FPL have not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

**Item 16. Form 10-K Summary**

Not applicable

## NEXTERA ENERGY, INC. SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized and in the capacities and on the date indicated.

NextEra Energy, Inc.

**JAMES L. ROBO**

**James L. Robo**
Chairman, President and Chief Executive Officer
and Director
(Principal Executive Officer)

Date: February 14, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature and Title as of February 14, 2020:

**REBECCA J. KUJAWA**

**Rebecca J. Kujawa**
Executive Vice President, Finance
and Chief Financial Officer
(Principal Financial Officer)

**JAMES M. MAY**

**James M. May**
Vice President, Controller and Chief Accounting
Officer
(Principal Accounting Officer)

Directors:

**SHERRY S. BARRAT**
**Sherry S. Barrat**

**AMY B. LANE**
**Amy B. Lane**

**JAMES L. CAMAREN**
**James L. Camaren**

**DAVID L. PORGES**
**David L. Porges**

**KENNETH B. DUNN**
**Kenneth B. Dunn**

**RUDY E. SCHUPP**
**Rudy E. Schupp**

**NAREN K. GURSAHANEY**
**Naren K. Gursahaney**

**JOHN L. SKOLDS**
**John L. Skolds**

**KIRK S. HACHIGIAN**
**Kirk S. Hachigian**

**WILLIAM H. SWANSON**
**William H. Swanson**

**TONI JENNINGS**
**Toni Jennings**

**HANSEL E. TOOKES, II**
**Hansel E. Tookes, II**

**DARRYL L. WILSON**
**Darryl L. Wilson**

## FLORIDA POWER & LIGHT COMPANY SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized and in the capacities and on the date indicated.

Florida Power & Light Company

**ERIC E. SILAGY**

**Eric E. Silagy**
President and Chief Executive Officer and Director
(Principal Executive Officer)

Date: February 14, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature and Title as of February 14, 2020:

**REBECCA J. KUJAWA**

**Rebecca J. Kujawa**
Executive Vice President, Finance
and Chief Financial Officer and Director
(Principal Financial Officer)

**KEITH FERGUSON**

**Keith Ferguson**
Controller
(Principal Accounting Officer)

Director:

**JAMES L. ROBO**

**James L. Robo**

**Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Securities Exchange Act of 1934 by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Securities Exchange Act of 1934**

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of FPL during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

**Exhibit 31(a)**

## Rule 13a-14(a)/15d-14(a) Certification

I, James L. Robo, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2019 of NextEra Energy, Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2020

**JAMES L. ROBO**

James L. Robo
Chairman, President and Chief Executive Officer
of NextEra Energy, Inc.

**Exhibit 31(b)**

## Rule 13a-14(a)/15d-14(a) Certification

I, Rebecca J. Kujawa, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2019 of NextEra Energy, Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2020

**REBECCA J. KUJAWA**

Rebecca J. Kujawa
Executive Vice President, Finance and
Chief Financial Officer
of NextEra Energy, Inc.

**Exhibit 31(c)**

## Rule 13a-14(a)/15d-14(a) Certification

I, Eric E. Silagy, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2019 of Florida Power & Light Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2020

**ERIC E. SILAGY**

Eric E. Silagy
President and Chief Executive Officer
of Florida Power & Light Company

**Exhibit 31(d)**

## Rule 13a-14(a)/15d-14(a) Certification

I, Rebecca J. Kujawa, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2019 of Florida Power & Light Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2020

**REBECCA J. KUJAWA**

Rebecca J. Kujawa
Executive Vice President, Finance
and Chief Financial Officer
of Florida Power & Light Company

**Exhibit 32(a)**

## Section 1350 Certification

We, James L. Robo and Rebecca J. Kujawa, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Annual Report on Form 10-K of NextEra Energy, Inc. (the registrant) for the annual period ended December 31, 2019 (Report) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

Dated: February 14, 2020

**JAMES L. ROBO**

James L. Robo
Chairman, President and Chief Executive Officer
of NextEra Energy, Inc.

**REBECCA J. KUJAWA**

Rebecca J. Kujawa
Executive Vice President, Finance and
Chief Financial Officer
of NextEra Energy, Inc.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 and, accordingly, is not being filed with the Securities and Exchange Commission as part of the Report and is not to be incorporated by reference into any filing of the registrant under the Securities Act of 1933 or the Securities Exchange Act of 1934 (whether made before or after the date of the Report, irrespective of any general incorporation language contained in such filing).

**Exhibit 32(b)**

## Section 1350 Certification

We, Eric E. Silagy and Rebecca J. Kujawa, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Annual Report on Form 10-K of Florida Power & Light Company (the registrant) for the annual period ended December 31, 2019 (Report) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

Dated: February 14, 2020

**ERIC E. SILAGY**

Eric E. Silagy
President and Chief Executive Officer
of Florida Power & Light Company

**REBECCA J. KUJAWA**

Rebecca J. Kujawa
Executive Vice President, Finance
and Chief Financial Officer
of Florida Power & Light Company

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 and, accordingly, is not being filed with the Securities and Exchange Commission as part of the Report and is not to be incorporated by reference into any filing of the registrant under the Securities Act of 1933 or the Securities Exchange Act of 1934 (whether made before or after the date of the Report, irrespective of any general incorporation language contained in such filing).

# BOARD OF DIRECTORS

**JAMES L. ROBO**
Chairman of the Board and Chief Executive Officer, NextEra Energy, Inc.
*Director since 2012.*
*Chair: Executive Committee.*

**SHERRY S. BARRAT**
Retired. Formerly Vice Chairman, Northern Trust Corporation
(financial holding company)
*Director since 1998.*
*Member: Compensation Committee, Finance & Investment Committee.*

**JAMES L. CAMAREN**
Private Investor. Formerly Chairman & Chief Executive Officer, Utilities, Inc.
(water utilities)
*Director since 2002.*
*Member: Compensation Committee, Governance & Nominating Committee.*

**KENNETH B. DUNN**
Emeritus Professor of Financial Economics and former Dean,
Tepper School of Business, Carnegie Mellon University
(higher education)
*Director since 2010.*
*Member: Audit Committee, Finance & Investment Committee.*

**NAREN K. GURSAHANEY**
Retired. Formerly President and Chief Executive Officer, ADT Corporation
(electronic security services)
*Director since 2014.*
*Member: Audit Committee, Governance & Nominating Committee.*

**KIRK S. HACHIGIAN**
Chairman of the Board, JELD-WEN, Inc.
(window and door manufacturer)
*Director since 2013.*
*Chair: Compensation Committee.*
*Member: Governance & Nominating Committee, Executive Committee.*

**TONI JENNINGS**
Chairman, Jack Jennings & Sons, Inc.
(construction)
Former Lt. Governor, State of Florida
*Director since 2007.*
*Member: Audit Committee, Governance & Nominating Committee.*

**AMY B. LANE**
Retired. Formerly Investment Banker, Merrill Lynch & Co., Inc.
(investment banking firm)
*Director since 2015.*
*Chair: Finance & Investment Committee.*
*Member: Compensation Committee, Executive Committee.*

**DAVID L. PORGES**
Retired. Formerly Chairman of the Board, Equitrans Midstream Corporation
(natural gas midstream operator)
*Director since 2020.*
*Member: Finance & Investment Committee*

**RUDY E. SCHUPP**
Retired. Formerly President, Valley National Bancorp and Chief Banking Officer, Valley National Bank
(commercial bank)
*Director since 2005.*
*Lead Director.*
*Chair: Governance & Nominating Committee.*
*Member: Finance & Investment Committee, Executive Committee.*

**JOHN L. SKOLDS**
Retired. Formerly Executive Vice President of Exelon Corporation and President of Exelon Energy Delivery and Exelon Generation
(utility services holding company)
*Director since 2012.*
*Chair: Nuclear Committee.*
*Member: Audit Committee.*

**WILLIAM H. SWANSON**
Retired. Formerly Chairman of the Board and Chief Executive Officer, Raytheon Company
(global defense technology)
*Director since 2009.*
*Chair: Audit Committee.*
*Member: Finance & Investment Committee, Executive Committee.*

**HANSEL E. TOOKES, II**
Retired. Formerly President, Raytheon International
(defense and aerospace systems)
*Director since 2005.*
*Member: Compensation Committee, Finance & Investment Committee.*

**DARRYL L. WILSON**
Retired. Formerly Vice President, Commercial of GE Power
(power generation manufacturing)
*Director since 2018.*
*Member: Audit Committee.*

PROPOSED 2020 COMMON STOCK DIVIDEND DATES*

| Declaration | Ex-Dividend | Record | Payment |
|---|---|---|---|
| February 14 | February 27 | February 28 | March 16 |
| May 22 | June 1 | June 2 | June 15 |
| July 30 | August 27 | August 28 | September 15 |
| October 16 | November 25 | November 27 | December 15 |

*Declaration of dividends and dates shown are subject to the discretion of the Board of Directors of NextEra Energy, Inc.
Dates shown are based on the assumption that past patterns will prevail.

# INVESTOR INFORMATION

**CORPORATE OFFICES**
NextEra Energy, Inc.
700 Universe Blvd.
Juno Beach, FL 33408

**EXCHANGE LISTING**
*Common Stock*
New York Stock Exchange
Ticker Symbol: NEE

*NextEra Energy Capital Holdings, Inc. Series I Junior Subordinated Debentures*
New York Stock Exchange
Ticker Symbol: NEE.PRI

*NextEra Energy Capital Holdings, Inc. Series J Junior Subordinated Debentures*
New York Stock Exchange
Ticker Symbol: NEE.PRJ

*NextEra Energy Capital Holdings, Inc. Series K Junior Subordinated Debentures*
New York Stock Exchange
Ticker Symbol: NEE.PRK

*NextEra Energy Capital Holdings, Inc. Series N Junior Subordinated Debentures*
New York Stock Exchange
Ticker Symbol: NEE.PRN

*NextEra Energy Capital Holdings, Inc. Series J Senior Debentures (Corporate Unit)*
New York Stock Exchange
Ticker Symbol: NEE.PRO

*NextEra Energy Capital Holdings, Inc. Series K Senior Debentures (Corporate Unit)*
New York Stock Exchange
Ticker Symbol: NEE.PRP

**NEWSPAPER LISTING**
*Common Stock:* NEE

**REGISTRAR, TRANSFER AND PAYING AGENTS**
*NextEra Energy, Inc. Common Stock*

NextEra Energy, Inc.
c/o Computershare
P.O. Box 505000
Louisville, KY 40233-5000

*Florida Power & Light Company First Mortgage Bonds*

Deutsche Bank Trust
Company Americas
5022 Gate Parkway
Suite 200
Jacksonville, FL 32256
800-735-7777

*Gulf Power Company Debentures*

Wells Fargo Bank, N.A.
Corporate Trust Operations
MAC N9300-070
600 South Fourth Street
Minneapolis, MN 55402
Attn: Bondholder Communications:
1-800-344-5128.

*NextEra Energy Capital Holdings, Inc. Debentures*

*NextEra Energy Capital Holdings, Inc. Junior Subordinated Debentures*

*NextEra Energy, Inc. Corporate Units*

The Bank of New York Mellon
Bondholder Relations
111 Sanders Creek Parkway
East Syracuse, NY 13057
800-254-2826

**SHAREHOLDER INQUIRIES**
Communications concerning transfer requirements, lost certificates, dividend checks, address changes, stock accounts and the dividend reinvestment and direct stock purchase plan should be directed to Computershare: 888-218-4392 or **www.computershare.com/NEE**.

Other shareholder communications to: Shareholder Services 800-222-4511

**ELECTRONIC PROXY MATERIAL**
Shareholders may elect to receive proxy materials electronically by accessing **https://enroll.icsdelivery.com/NEE**.

**DIRECT DEPOSIT OF DIVIDENDS**
Cash dividends may be deposited directly to personal accounts at financial institutions. Call Computershare for authorization forms.

**DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN**
NextEra Energy offers a plan for the reinvestment of dividends and the purchase of common stock. Enrollment materials may be obtained by calling Computershare or by accessing **www.computershare.com/NEE**.

**DIRECT REGISTRATION SERVICES**
NextEra Energy common stock can be issued in direct registration (book entry) form.

**ONLINE INVESTOR INFORMATION**
Visit our investor information site at **NextEraEnergy.com/investors** to get stock quotes, earnings reports, financial releases, SEC filings and other news. You can also request and receive information via email. Shareholders of record can receive secure online account access through a link to Computershare.

**SEC FILINGS**
All Securities and Exchange Commission filings appear at **NextEraEnergy.com/investors**. Copies of SEC filings also are available without charge by writing to NextEra Energy, Shareholder Services.

**NEWS AND FINANCIAL INFORMATION**
Get the latest news and financial information about NextEra Energy by visiting **NextEraEnergy.com**.

**ANALYST INQUIRIES**
Investor Relations
561-694-4697

**NEWS MEDIA INQUIRIES**
Media Relations
561-694-4442

**CERTIFIED PUBLIC ACCOUNTANTS**
Deloitte & Touche LLP
1800 North Military Trail
Suite 200
Boca Raton, FL 33431-6386

NextEra Energy, Inc. (NYSE: NEE) is a leading clean energy company headquartered in Juno Beach, Florida. NextEra Energy owns two electric companies in Florida: Florida Power & Light Company, which serves more than 5 million customer accounts in Florida and is the largest rate-regulated electric utility in the United States as measured by retail electricity produced and sold; and Gulf Power Company, which serves more than 470,000 customers in eight counties throughout northwest Florida. NextEra Energy also owns a competitive energy business, NextEra Energy Resources, LLC, which, together with its affiliated entities, is the world's largest generator of renewable energy from the wind and sun and a world leader in battery storage. Through its subsidiaries, NextEra Energy generates clean, emissions-free electricity from eight commercial nuclear power units in Florida, New Hampshire, Iowa and Wisconsin. A Fortune 200 company and included in the S&P 100 index, NextEra Energy has been recognized often by third parties for its efforts in sustainability, corporate responsibility, ethics and compliance, and diversity. NextEra Energy is ranked No. 1 in the electric and gas utilities industry on Fortune's 2020 list of "World's Most Admired Companies" and ranked among the top 25 on Fortune's 2018 list of companies that "Change the World." For more information about NextEra Energy companies, visit these websites: **NextEraEnergy.com, FPL.com, GulfPower.com, NextEraEnergyResources.com.**

NextEra Energy, Inc.
700 Universe Boulevard
Juno Beach, FL 33408

For more information, go to:
NextEraEnergy.com
FPL.com
GulfPower.com
NextEraEnergyResources.com

103122

# ENBRIDGE 2019 ANNUAL REPORT

Filed: 2020-11-04
EB-2020-0150
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ENBRIDGE
Life Takes Energy

# 2019 Annual Report

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Investor Information

Flanagan Terminal

# Enbridge Today

Enbridge is North America's largest energy infrastructure company with an extensive leading network of crude oil, natural gas and renewable energy. Our purpose is to fuel quality of life by delivering energy, safely and reliably. Our 13,000-person team brings enthusiasm and ingenuity to work every day in support of this mission.

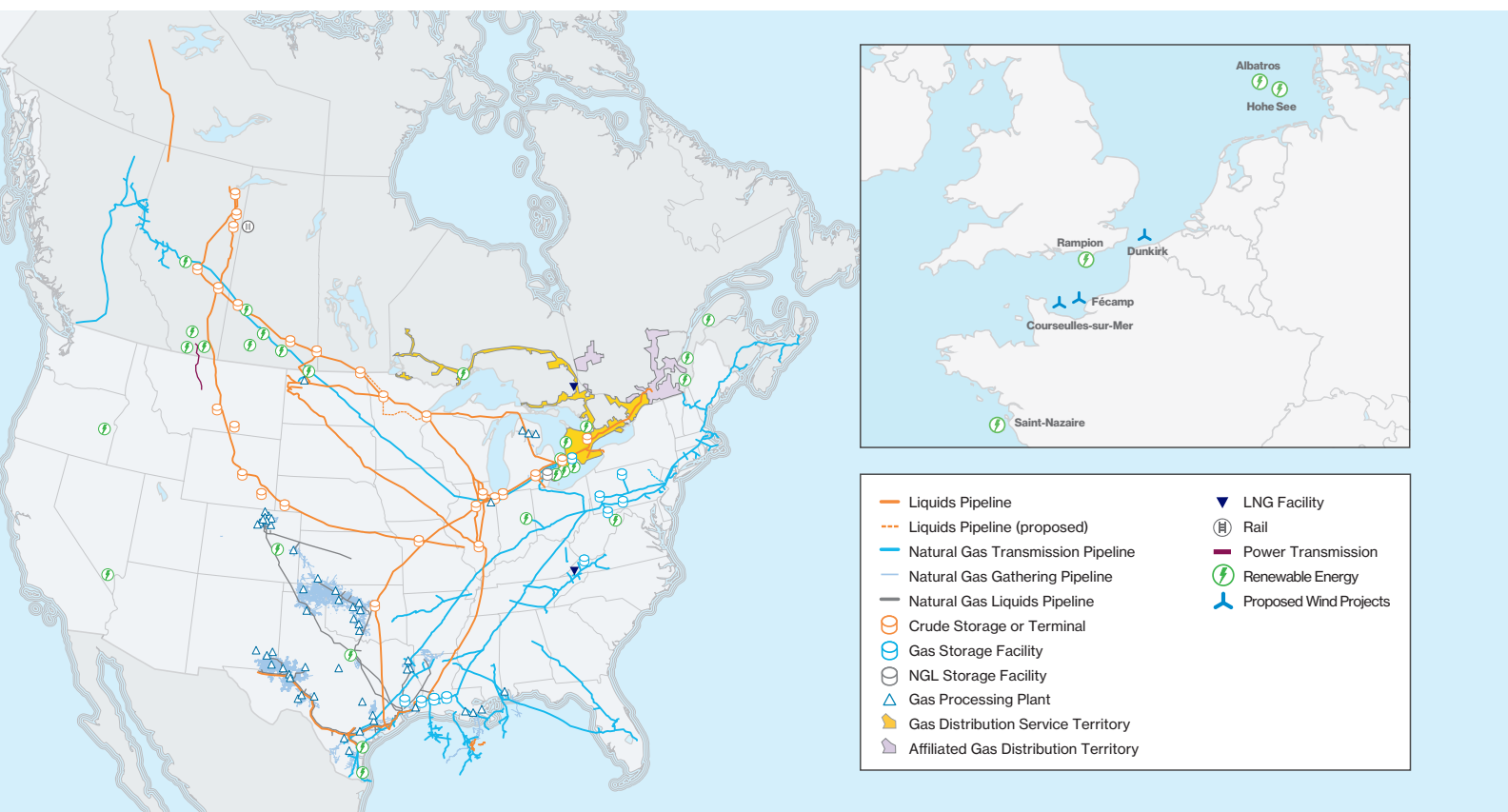
We connect energy supply to the best markets in North America through our three core businesses, and our growing renewable power generation business — to provide energy that's critical to everyday life and drives our economy.

**Liquids Pipelines** moves approximately 25% of North American crude oil demand, serving 12 million barrels per day (bpd) of refining capacity and connecting producers to the best markets in the U.S. Midwest, the Gulf Coast and Eastern Canada.

**Gas Transmission and Midstream** transports nearly 20% of the natural gas consumed in the U.S., connecting to key residential, industrial and commercial markets totaling approximately 170 million people as well as power generation facilities across the continent.

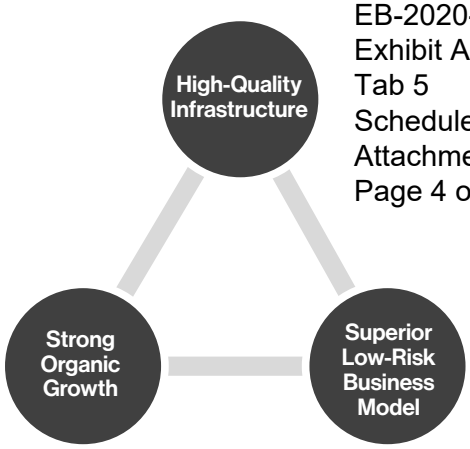
**Gas Distribution and Storage** (Enbridge Gas) is the largest natural gas utility in North America by throughput and serves approximately 12 million people with our 3.8 million meter connections in Ontario and Quebec.

**Renewable Power Generation** has interests in more than 30 renewable power facilities, including a growing presence in offshore wind in Europe. Our operating facilities have the capacity to generate about 1,750 MW (net ownership) of zero-emission energy in North America and Europe, which is enough energy to power about 700,000 homes.

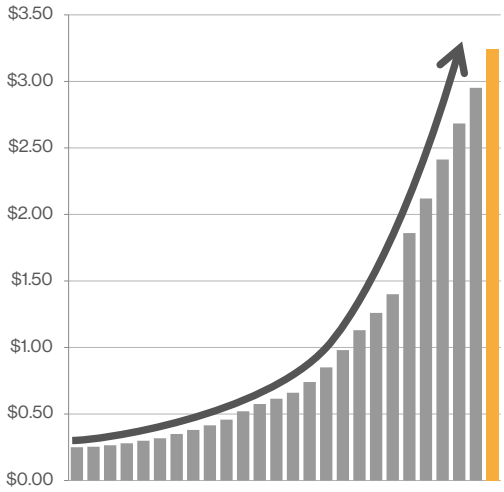


**Our value proposition** is straightforward and consistent: we invest in high-quality, long-lived assets that fit within our low-risk business model and generate stable, predictable cash flows and strong organic growth. We call this our Pipeline-Utility business model and it's illustrated by our value proposition triangle.

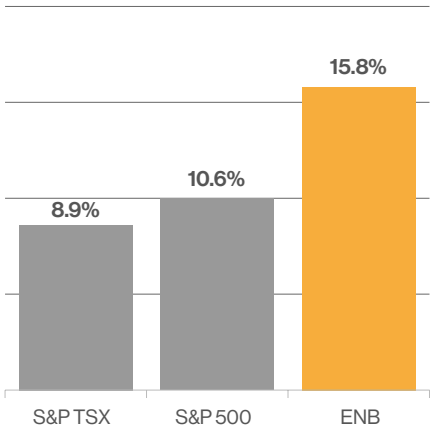
Our business model has proven to be successful and has created long-term value for shareholders. We've delivered 25 years of consecutive dividend growth and we've outperformed the S&P 500 by more than 15% over the same period.




## Dividend Growth
(1995 – 2020)




## Total Shareholder Return
(1995 – 2019)



**Our approach to the business is guided by our values of safety, integrity and respect.**
These values help us to establish trust with our people, customers and the hundreds of communities we serve across North America.

We engage regularly with various stakeholder and Indigenous groups who live and work near our operations, and our aim is to build long-term relationships by addressing concerns, respecting culture and designing projects that create mutual benefits. We believe strongly in supporting the communities where we live and operate – by giving back and contributing to their strength and vitality.

Our priority is to protect our people, communities and the environment, and we believe that all incidents can be prevented. Safety is not just a value; it's the very foundation of our business.

# Letter to Shareholders

We're very pleased to report that 2019 was another strong year for Enbridge and our investors. We delivered solid operating and financial results, advanced our strategic priorities and focused on further improving the safety and reliability of our assets.

## Completion of our three-year plan

2019 marked the final year of the three-year plan we established following the acquisition of Spectra Energy in 2017. By bringing Spectra into the fold, we accelerated our gas strategy and expanded our U.S. presence, and today, it's even clearer it was the right thing to do. Not only has it diversified our asset mix, opportunity set and geography, which has made us more resilient; it has also repositioned Enbridge for the future and the changing energy landscape.

Over the past three years, we completed Spectra integration and exceeded the synergies we targeted from the deal, and we greatly simplified our corporate structure. We've sold $8 billion of assets that were not part of our future, markedly strengthened our balance sheet and financial flexibility, and placed $28 billion of new projects into service. Given the strength of our business and growth outlook, we increased the dividend by 10% annually over the last three years. This contributed to a total shareholder return of 30% in 2019 and a great outcome for shareholders.

## 2019 look back

We made excellent progress on our strategic priorities last year, particularly with our focus on optimizing our asset base, enhancing returns and extending our growth outlook while preserving our financial strength and our low-risk business model.

- We delivered record financial results and distributable cash flow (DCF) per share of $4.57, at the top end of our guidance range. Year-end Debt:EBITDA was 4.5x, which is the very strong end of our 4.5–5.0x target. We increased our 2020 annual dividend by approximately 10% to $3.24 per share, which marks 25 years of consecutive dividend increases for our shareholders.
- We strengthened our core business by enabling 100,000 barrels per day of throughput optimizations to our Mainline system, completing our first rate case in 28 years on our Texas Eastern system and capturing synergies from the amalgamation of our Ontario natural gas utilities.
- We placed $9 billion of new projects into service, including the Canadian segment of the Line 3 Replacement Project (L3RP), the Gray Oak pipeline in the U.S. Gulf Coast and the Hohe See offshore wind project in Germany.

**Gregory L. Ebel**
Chair,
Board of Directors

**Al Monaco**
President & Chief
Executive Officer

- We've progressed a slate of $11 billion of secured growth projects that are diversified, low risk and capital efficient. These include the U.S. segment of L3RP, modernization projects in Gas Transmission and Midstream, customer-growth and expansions in our utility, and one offshore wind project in France.
- We advanced our energy export strategy by announcing new projects in the U.S. Gulf Coast that extend our integrated value chain and leverage our existing footprint, including the acquisition of the Rio Bravo Pipeline development project and an option to purchase interest in an offshore VLCC-capable oil export terminal.
- We continued to enhance our environment, social and governance (ESG) performance and disclosure, including: enabling $450 million of economic opportunities for Indigenous groups along our Line 3 Canada right-of-way; issuing our first climate report that outlines our climate-related risks, strategies and approach to energy transition; and advancing our diversity strategy to increase the number of women on the board to 42% and in senior management roles nearing 30%.

**30%** total shareholder return
**3** years of 10% dividend increases
**25** consecutive years of dividend increases

### Challenges

While we had good results in many areas of safety and reliability in 2019, we experienced incidents in our Gas Transmission and Midstream business, one of which caused a fatality. All of our hearts at Enbridge go out to the family. No incident is acceptable to us and we've taken steps in response to these events to deepen our resolve to further enhance the safety and integrity of our systems.

Although we were disappointed by the regulatory delay to our Line 3 Replacement Project in Minnesota, we have strong support from the communities and Tribal Nations along the route. Ultimately, the segment must be replaced to assure safety, reliability and environmental protection. In February 2020, the Minnesota Public Utilities Commission re-certified the Environmental Impact Statement and Certificate of Need and Route Permit, which allow us to progress the remaining permits. We continue to work closely with State and Federal agencies to secure all necessary permits required to commence construction.

## Enbridge's resilience for the future

We've come out of 2019 in a strong position with great assets that provide resiliency to the changing energy landscape. Our best-in-class liquids, natural gas transmission and natural gas utility businesses provide reach and diverse options to grow, and we're connected to the best markets in North America, including export links. The energy we deliver is essential to the North American economy, and millions of people rely on it every day in every aspect of their lives. Importantly, our assets will continue to serve our customers and their communities long into the future.

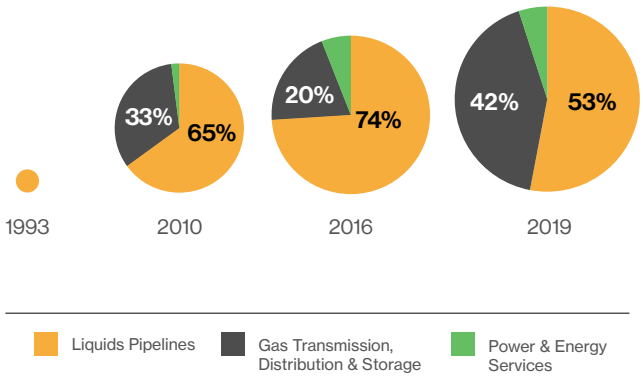
We have the financial strength and flexibility to execute on our strategic plan, and take advantage of emerging opportunities in an evolving and transitioning energy market – and we have the very best people to make it happen.

Long ago, we began integrating ESG principles into our strategy and decision-making, and today ESG is core to our long-term value and resilience.

It's clear from the actions we've taken that Enbridge is already playing an active role in the energy transition.

By responding to energy fundamentals, we've transformed our business, from largely liquids-pipeline focused to an increasingly diversified business mix with natural gas and renewables.

**Repositioning Our Business**
(Asset mix*)




*Size of pie represents earnings before interest, income tax and depreciation and amortization (EBITDA).

We're proud of our role to deliver energy that millions of people rely on every day in every aspect of their lives.

We've made significant investments into our renewables business over the past two decades and built a solid operating and development capability in this growing part of our business. In addition to our three operating offshore windfarms in Europe, we're advancing four new development projects in offshore France, which will help grow this business into a new Enbridge platform.

We've set and met our own emissions targets, lowering direct energy emissions by 21% between 2005 and 2011. And our energy conservation programs, which have been in place since 1995, have helped our utility customers save energy and resulted in emissions reductions equivalent to taking 10 million cars off the road.

We'll continue to do our part to reduce emissions and conserve energy, while at the same time meeting society's growing need for sustainable energy.

Even though we've led our sector in many aspects of energy efficiency and conservation, we're setting the next phase of emissions reductions targets.

We're investing in low-carbon innovation and greening the gas grid, including: renewable natural gas that captures methane in landfills; our power-to-gas-facility – the first in North America – that allows us to inject hydrogen into the gas grid to reduce carbon content; and compressed natural gas.

We're also now beginning to invest in self-powering our pipeline assets with our own renewable power plants.

For more information on our ESG performance and disclosure, please review our 2019 Climate Report and our 2018 Sustainability Report.

***Resilient Energy Infrastructure: Addressing Climate-Related Risks and Opportunities Report***
enbridge.com/Sustainability-Reports/Resilient-Energy-Infrastructure

***Building Connections: 2018 Sustainability Report***
enbridge.com/sustainability-reports/sustainability-report-2018

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## Looking ahead

At Enbridge, we've always focused on improving returns from existing assets and allocating cash flow generated from those assets to the opportunities that sustain long-term growth.

### Opportunity set

Post completion of our secured capital program, we'll have $5 billion to $6 billion of available capital and financial capacity – within our equity self-funding model – to re-invest in the business, and we expect annual DCF per share growth to be 5 to 7%. We'll continue to be disciplined about where we invest, prioritizing capital-efficient opportunities that are in our expansive footprint.

Within each core business, we're seeing opportunities to increase revenue, reduce costs and further improve our operations. We'll continue to optimize and expand our core franchises, with a focus on energy-export infrastructure with our integrated Liquids and Gas Pipeline platforms and investment in our Gas Distribution franchise to grow its customer base. We'll also grow our Renewable Power division by developing new offshore wind projects that fit our low-risk business model.

### Embracing technology

Another area of opportunity we're leveraging in a big way is technology. We're using technology to improve business performance and find solutions to drive higher levels of safety, reliability and productivity. Last year, we established a Technology + Innovation Lab, with locations in Calgary and Houston, to bring together business and operations people with technology experts to tackle problems using machine learning, Ai and predictive analytics. We've adopted agile ways of working to deliver progress quickly – and we're beginning to see results. For example, in Liquids we built a "simulation engine" to optimize how crude flows through our pipeline system, and in Gas Transmission and Midstream we're using digital platforms to better assess the integrity of our gas system and predict where to prioritize maintenance.

### People

We believe it's vitally important to continue to strengthen our organizational capabilities by developing our people and helping them advance their careers. In 2019, we expanded our executive leadership team as part of a broader succession-planning and development effort.

We're also focused on building a diverse team and inclusive culture where everyone feels valued. This is important for two reasons; first, fairness, equity and merit are core to our values, and second, we believe that diversity of thought leads to improving our business. We set diversity targets in 2018 and we're beginning to see progress. Today, 42% of our Board is comprised of women and 28% of senior leadership roles are held by women.

### Leading ESG performance and approach

ESG is not new to Enbridge – environmental and social considerations have long been integrated into how we think about our business. We have strong Board oversight in this area and our Corporate Social Responsibility and Safety & Reliability Board committees have been in place for more than 15 years. We report annually on the ESG factors of greatest relevance to our stakeholders: climate and energy transition, safety and asset integrity, and community and Indigenous engagement. Our disclosure and performance have earned us strong ESG ratings from investors. We're proud of our standing and we're focused on maintaining industry leadership.

## Final thoughts

We'd like to thank all members of the team for their continuing dedication to Enbridge.

We'd also like to thank our Board of Directors for their guidance and strong governance. Our Board possesses a wide range of skills, experience and knowledge to steer our company forward into the future.

We were saddened by the passing last year of Michael Phelps who was a valued director and friend. He will be missed by us all.

In February 2020, we welcomed Gregory J. Goff as a director. He brings extensive experience in energy and will be a strong addition to our Board. And this year, we say farewell to one of our longest-serving directors, Cathy Williams. Cathy has made valuable contributions during her tenure, particularly through her leadership on our Human Resources and Governance committees.

Today, Enbridge's diversified asset base provides reach and scale that makes us resilient and gives us many options to grow. We provide critical energy to the best markets and to millions of people. Our business model, our commitment to people, safety and the environment, and our track record of evolving our business and adapting to changing markets will allow us to prosper and deliver shareholder value for decades to come.

**Gregory L. Ebel**

**Al Monaco**

March 3, 2020

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

## FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2019**

**or**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to**

**Commission file number 1-10934**

## ENBRIDGE INC.
(Exact Name of Registrant as Specified in Its Charter)

| **Canada** | **98-0377957** |
|---|---|
| (State or Other Jurisdiction of Incorporation or Organization) | (I.R.S. Employer Identification No.) |

**200, 425 - 1st Street S.W.**
**Calgary, Alberta, Canada T2P 3L8**
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code **(403) 231-3900**

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|
| Common Shares | ENB | New York Stock Exchange |
| 6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078 | ENBA | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.Yes ☒ No ☐
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.Yes ☐ No ☒
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.Yes ☒ No ☐
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).Yes ☒ No ☐
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large Accelerated Filer | ☒ | Accelerated Filer | ☐ |
| Non-Accelerated Filer | ☐ | Smaller reporting company | ☐ |
| Emerging growth company | ☐ | | |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes ☐ No ☒
The aggregate market value of the registrant's common shares held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2019, was approximately US$73.1 billion.
As at February 7, 2020, the registrant had 2,024,814,011 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Not applicable.

# EXPLANATORY NOTE

Enbridge Inc., a corporation existing under the *Canada Business Corporations Act*, qualifies as a foreign private issuer in the United States for purposes of the Securities Exchange Act of 1934, as amended (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is no longer required to do so, Enbridge Inc. currently continues to file annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K with the Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers.

Enbridge Inc. intends to prepare and file a management proxy circular and related material under Canadian requirements. As Enbridge Inc.'s management proxy circular is not filed pursuant to Regulation 14A, Enbridge Inc. may not incorporate by reference information required by Part III of this Form 10-K from its management proxy circular. Accordingly, in reliance upon and as permitted by Instruction G(3) to Form 10-K, Enbridge Inc. will be filing an amendment to this Form 10-K containing the Part III information no later than 120 days after the end of the fiscal year covered by this Form 10-K.

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# GLOSSARY

| | |
|---|---|
| AOCI | Accumulated other comprehensive income/(loss) |
| ARO | Asset retirement obligations |
| ASU | Accounting Standards Update |
| BC | British Columbia |
| bcf/d | Billion cubic feet per day |
| bpd | Barrels per day |
| CER | The Canadian Regulator Act created the new Canada Energy Regulator and repealed the National Energy Board Act, on August 28, 2019 |
| CPPIB | Canada Pension Plan Investment Board |
| CTS | Competitive Toll Settlement |
| Dawn | Dawn Hub |
| DCP Midstream | DCP Midstream, LLC |
| EBITDA | Earnings before interest, income taxes and depreciation and amortization |
| EEM | Enbridge Energy Management, L.L.C. |
| EEP | Enbridge Energy Partners, L.P. |
| EGD | Enbridge Gas Distribution Inc. |
| Enbridge | Enbridge Inc. |
| ENF | Enbridge Income Fund Holdings Inc. |
| FEIS | Final Environmental Impact Statement |
| FERC | Federal Energy Regulatory Commission |
| Flanagan South | Flanagan South Pipeline |
| GHG | Greenhouse gas |
| ISO | Incentive Stock Options |
| LIBOR | London Interbank Offered Rate |
| LMCI | Land Matters Consultation Initiative |
| LNG | Liquefied natural gas |
| MATL | Montana-Alberta Tie-Line |
| MD&A | Management's Discussion and Analysis |
| Merger Transaction | Combination of Enbridge and Spectra Energy through a stock-for-stock merger transaction which closed on February 27, 2017 |
| MNPUC | Minnesota Public Utilities Commission |
| MOLP | Midcoast Operating, L.P. and its subsidiaries |

| | |
|---|---|
| MW | Megawatts |
| NGL | Natural gas liquids |
| Noverco | Noverco Inc. |
| NYSE | New York Stock Exchange |
| OCI | Other comprehensive income/(loss) |
| OEB | Ontario Energy Board |
| OPEB | Other postretirement benefit obligations |
| RSU | Restricted Stock Units |
| Sabal Trail | Sabal Trail Transmission, LLC |
| Seaway Pipeline | Seaway Crude Pipeline System |
| SEP | Spectra Energy Partners, LP |
| Spectra Energy | Spectra Energy Corp |
| Sponsored Vehicles buy-in | In the fourth quarter of 2018, Enbridge Inc. completed the buy-ins of our sponsored vehicles: Spectra Energy Partners, LP (SEP), Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) and Enbridge Income Fund Holdings Inc. (ENF), (collectively, the Sponsored Vehicles), where we acquired, in separate combination transactions, all of the outstanding equity securities of those Sponsored Vehicles not beneficially owned by us. |
| TCJA | Tax Cuts and Jobs Act |
| Texas Eastern | Texas Eastern Transmission, L.P. |
| the Fund | Enbridge Income Fund |
| TSX | Toronto Stock Exchange |
| Union Gas | Union Gas Limited |
| U.S. GAAP | Generally accepted accounting principles in the United States of America |
| U.S. L3R Program | United States portion of the Line 3 Replacement Program |
| Vector | Vector Pipeline L.P. |
| VIE | Variable interest entities |
| WCSB | Western Canadian Sedimentary Basin |

## CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to “dollars”, “$” or “C$” are to Canadian dollars and all references to “US$” are to United States dollars. All amounts are provided on a before tax basis, unless otherwise stated.

## FORWARD-LOOKING INFORMATION

*Forward-looking information, or forward-looking statements, have been included in this Annual Report on Form 10-K to provide information about us and our subsidiaries and affiliates, including management’s assessment of our and our subsidiaries’ future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as “anticipate”, “believe”, “estimate”, “expect”, “forecast”, “intend”, “likely”, “plan”, “project”, “target” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; expected distributable cash flow; expected debt-to-EBITDA ratio; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions, including the realization of efficiencies and synergies; expected future actions of regulators and related court proceedings and other litigation; expectations regarding commodity prices; supply and demand forecasts; anticipated utilization of our existing assets; anticipated competition; United States Line 3 Replacement Program (U.S. L3R Program); Line 5 related matters; Mainline System contracting; Texas Eastern rate case; estimated future dividends; our dividend payout policy; dividend growth and dividend payout expectation; and expectations on impact of our hedging program.*

*Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits and synergies of transactions; governmental legislation; impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected future cash flows; expected distributable cash flow; and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected EBITDA, expected earnings/(loss), expected future cash flows, expected distributable cash flow or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including*

*estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.*

*Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance, regulatory parameters, changes in regulations applicable to our business, acquisitions, dispositions and other transactions, our dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this Annual Report on Form 10-K and in our other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge Inc. assumes no obligation to publicly update or revise any forward-looking statement made in this Annual Report on Form 10-K or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.*

# PART I

## ITEM 1. BUSINESS

We are a leading North American energy infrastructure company. We safely and reliably deliver the energy people need and want to fuel quality of life. Our core businesses include Liquids Pipelines, which transports approximately 25 percent of the crude oil produced in North America; Gas Transmission and Midstream, which transports approximately 20 percent of the natural gas consumed in the United States; Gas Distribution and Storage, which serves approximately 3.8 million retail customers in Ontario and Quebec; and Renewable Power Generation, which generates approximately 1,750 megawatts (MW) of net renewable power in North America and Europe. Our common shares trade on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol ENB. We were incorporated on April 13, 1970 under the Companies Ordinance of the Northwest Territories and were continued under the Canada Business Corporations Act on December 15, 1987.

A more detailed description of each of our businesses and underlying assets is provided below under *Business Segments.*

## CORPORATE VISION AND STRATEGY

**VISION**

Our vision is to be the leading energy infrastructure company in North America. In pursuing this vision, we play a critical role in enabling the economic well-being and quality of life of North Americans who depend on access to reliable energy. Our unparalleled infrastructure franchises transport, distribute and generate energy, and our primary purpose is to fuel quality of life by delivering the energy North Americans need and want, in the safest and most responsible way possible.

Our investor value proposition is founded on our ability to deliver predictable cash flows and a growing stream of dividends year-over-year through investment in and efficient operation of energy infrastructure assets that are strategically positioned between key supply basins and strong demand-pull markets. Our assets are underpinned by long-term contracts, regulated cost-of-service tolling frameworks and other low-risk commercial arrangements. Among our peers, we strive to be a leader in several key areas that create sustainable comparative advantage and value for shareholders including: worker and public safety, environmental protection, stakeholder relations, customer service, community investment and employee satisfaction.

**STRATEGY**

An in-depth understanding of supply and demand fundamentals has helped us become one of North America's largest energy infrastructure companies. Throughout our more than 70-year history, we have demonstrated the ability to respond to change and spot opportunity in energy transitions.

In recent years, we have become more resilient by diversifying our assets to reflect an evolving global energy mix. The 2017 acquisition of Spectra Energy Corp (Spectra Energy) is a notable example in that it substantially diversified our asset base across commodity types, energy basins and regulatory jurisdictions and created a significant new platform for sustainable growth. With a more diverse set of assets across our energy system, we have a unique vantage point from which to capitalize on current and future global energy trends.

On closing of the Spectra Energy transaction in early 2017, we embarked on an aggressive multi-year plan to position our newly combined company for long-term success. Key objectives included the realization of anticipated synergies through the quick and efficient integration of Spectra Energy's operations, strengthening of our balance sheet and business risk profile through the sale of non-core assets, the streamlining of our corporate structure through the buy-in of our four, publicly traded sponsored vehicles, ongoing execution of an industry-leading organic growth program and delivery of strong operating and financial performance.

With most of the key elements of that plan now substantially completed our focus has shifted to the optimization of our core asset base, enhancing our competitive positioning and securing new growth opportunities, all while continuing to execute on our secured capital program and the delivery of strong operating and financial performance.

During 2019 we made significant progress on a number of key objectives. For example:

- Completed the sale of our federally regulated Canadian midstream assets, bringing total proceeds from non-core asset sales over the last 3 years to approximately $8 billion;
- Brought into service approximately $9 billion of new growth projects including the Canadian component of the Line 3 Replacement Program on our Mainline System as well as the Atlantic Bridge (phase 1), Stratton Ridge and the Generation Pipeline Projects on our United States gas transmission system;
- Achieved a consolidated Debt-to-EBITDA ratio of 4.5x (on a trailing twelve month basis), the low end of our current target range;
- Optimized our liquids Mainline System operations to allow an incremental 100 thousand barrels per day (kbpd) of throughput;
- Successfully negotiated the Texas Eastern rate case, securing favorable regulatory treatment for a system-wide modernization program on our largest natural gas transmission pipeline;
- Further simplified our corporate structure with the amalgamation of our Ontario gas utilities;
- Achieved record financial results at the high end of our 2019 guidance range; and
- Increased our common share dividend by 9.8 percent.

**These achievements are discussed in further detail in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.***

Looking ahead, our near-term strategic priorities remain similar to years past. We remain focused on growing our three core business lines - Liquids Pipelines, Gas Transmission and Midstream, and Gas Distribution and Storage within a regulated pipeline and utility business model, while enhancing our competitive position by optimizing operations, maintaining a strong financial position and pursuing efficiencies through continuous process improvement and the application of technology solutions. As North American production of crude oil and natural gas is projected to exceed demand, we will continue to orient the development of our liquids and natural gas pipeline infrastructure toward export-driven opportunities that will further enhance the growth and resilience of our systems. Our renewable power generation business, anchored by investments in contracted offshore wind power, compliments our low risk business model and supports our increasing focus on energy transition. We will continue to invest in renewable power generation where we can achieve attractive risk adjusted returns.

Our key strategic priorities are summarized below:

**Commitment to Safety and Operational Reliability**
Safety and operational reliability remain the foundation of our strategy. Our commitment to safety and operational reliability means achieving and maintaining industry leadership in safety (process, public and personal) and ensuring the reliability and integrity of the systems we operate, in order to generate, transport and deliver energy while protecting people and the environment.

**Optimize Core Businesses**
A key priority is to drive growth through an ongoing focus on optimization, productivity and efficiency across all of our businesses. Examples include throughput enhancements on our liquids system from the application of drag-reducing agents and improvements in scheduling logistics at our terminals, revenue optimization through negotiated toll settlements or rate cases, ongoing synergy capture following our recent utility merger and, more generally, creating sustainable cost savings across the organization through process improvement and/or system enhancements.

**Execute and Extend Growth**
Successful project execution is integral to our financial performance and to the strategic positioning of our business over the long-term. Our ongoing objective is to deliver our slate of secured projects (currently $11 billion) at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

In seeking to extend growth, we expect to have sufficient self-funding capacity, post completion of our secured capital program, to invest $5 to $6 billion per year in new growth capital without issuing any additional common equity and maintaining key credit metrics within planning parameters and targets established with credit rating agencies.

Through 2040, we see strong utilization of our existing network and opportunities for future growth within each of our businesses. For example:

- Our liquids pipelines infrastructure will remain a vital connection between key supply basins and demand-pull markets, while the growing North American export market represents an opportunity to further expand midstream offerings and services.
- Our natural gas pipelines business plays an essential role in driving the North American economy, servicing markets totaling more than 170 million people. We expect natural gas to play an increasing role in power generation supporting the retirement of coal, while the growing Liquefied Natural Gas (LNG) export sector will drive opportunities to expand our existing network.
- Our gas distribution utility, serving the fifth largest population center in North America, is forecast to continue to provide customers with a significant cost advantage versus other fuels. In addition, technology is now being advanced and deployed to produce pipeline quality natural gas with a lower carbon footprint such as renewable natural gas.
- We also have several offshore wind projects in the advanced development phase. Growth in offshore wind is accelerating due to public policy support and technology advancement in the renewable energy sector. New renewable assets with long-term contracts will contribute to our low-risk growth.
- In all of our business segments, the replacement, renewal and modernization of our existing infrastructure is a further capital deployment opportunity.

**Maintain a Strong Financial Position**
The maintenance of our financial strength is critical to our strategy. Our financing strategies are designed to achieve strong, investment-grade credit ratings to ensure that we have the financial capacity to meet our capital funding needs and the flexibility to manage capital market disruptions and respond to opportunities as they arise. Our current secured capital program, which extends beyond 2020, can be readily financed through internally generated cash flow and available balance sheet capacity without issuance of additional common equity and we will seek to drive attractive growth post 2020 using this “self-funded” equity model. For further discussion on our financing strategies, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources*.

**Disciplined Capital Allocation**

As we seek growth, we assess the latest fundamental trends, monitor the business landscape and proactively conduct business development activities with the goal of identifying an industry-leading opportunity set for capital deployment. Opportunities are screened, analyzed and assessed using a disciplined investment framework with the objective of ensuring effective deployment of capital to achieve attractive risk-adjusted returns.

All projects are evaluated based on their potential to advance our strategy, sustain growth and create additional financial flexibility. Our primary emphasis is on projects that optimize and extend our existing footprint and position us for sustained long-term growth. Execution risk remains high for large scale, long-duration development projects and therefore, our focus will be on projects where we can carefully manage at-risk capital during the permitting and construction phases.

In evaluating typical investment opportunities we also consider other potential capital allocation choices that may add value. Other potential choices for capital deployment will depend on our current outlook and the size of our existing capital project backlog, and could include dividend increases, further debt reduction, a large scale acquisition or share re-purchases.

**Adapt to Energy Transition Over Time**

As the global population grows and standards of living continue to improve around the world, more energy will be needed. At the same time, our society increasingly recognizes the impacts of energy consumption on the world's climate. Accordingly, energy systems are being reshaped as industry participants, regulators and consumers seek to balance competing objectives. As a diversified energy infrastructure company, we are well positioned to play a key role in the transition to a lower-carbon economy while working to reduce our own emissions intensity at the same time.

We believe that diversification and innovation will play a significant role in the transition to a lower carbon future. To date, we have made large investments in natural gas infrastructure and continue to see significant opportunity in renewable energy, particularly offshore wind. Furthermore, we have tested our existing assets for various energy transition scenarios and concluded that they are highly resilient and can be relied upon for stable cash flow generation well into the future.

**STRATEGIC ENABLERS**

Our success in executing on our strategic priorities is very much enabled by our commitment to environment, social and governance (ESG) issues, the quality and capabilities of our people and the extent to which we embrace technology and encourage innovation as a competitive advantage.

**ESG**

Our everyday decision-making is informed by ESG issues, delivering the energy people need and want in a way that is environmentally, socially and economically responsible is critical to the long-term sustainability of our business. We're focused on reducing the intensity of our own greenhouse gas (GHG) emissions from operations, helping customers reduce their energy use and GHG impact and investing in lower carbon solutions such as natural gas and renewable energy.

We're also focused on building and maintaining constructive relationships with local communities and other groups directly impacted by our activities over the life-cycle of our assets. Recognizing the distinct rights of Indigenous communities, we have dedicated accountabilities and resources focused on consultation and inclusion. Broadly, our goal is to build awareness and balanced dialogue on the role and value of the energy we deliver to our society and economy.

**People**
Our employees are essential to our long-term success and enhancing the capability of our people to maximize their potential is a key area of focus. We value diversity and have embedded inclusive practices throughout our programs and approach to people management. Furthermore, we strive to maintain industry competitive compensation and retention programs that provide both short-term and long-term performance incentives.

**Technology**
Given the competitive climate of today's energy sector, we recognize the vital role technology can play in helping us achieve our strategic objectives. Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology-driven business solutions. Leveraging the benefits of technology to contribute to safety, reliability and the profitability of assets has become entrenched in our everyday operations.

We provide annual progress updates related to the above initiatives in our annual Corporate Social Responsibility and Sustainability Report which can be found at http://csr.enbridge.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of, this Annual Report on Form 10-K***.

# BUSINESS SEGMENTS

Our activities are carried out through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution and Storage; Renewable Power Generation; and Energy Services, as discussed below.

During 2019, we renamed the Gas Distribution segment to Gas Distribution and Storage, and the Green Power and Transmission segment to Renewable Power Generation. The presentation of the prior years' tables have been revised in order to align with the current presentation.

# LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and related terminals in Canada and the United States that transport various grades of crude oil and other liquid hydrocarbons.

**MAINLINE SYSTEM**

The Mainline System is comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline is a common carrier pipeline system which transports various grades of oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/United States border near Gretna, Manitoba and Neche, North Dakota and from the United States/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern United States. The Canadian Mainline includes six adjacent pipelines with a combined capacity of approximately 2.9 million barrels per day (bpd) that connect with the Lakehead System at the Canada/United States border, as well as five pipelines that deliver crude oil and refined products into eastern Canada and the northeastern United States. We have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the Mainline System in the United States. It is an interstate common carrier pipeline system regulated by FERC, and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States.

**Competitive Toll Settlement**

The Competitive Toll Settlement (CTS) is the current framework governing tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis. The 10-year settlement was negotiated by representatives of Enbridge, the Canadian Association of Petroleum Producers and other shippers on the Canadian Mainline. It was approved by the Canada Energy Regulator (CER), formerly the National Energy Board on June 24, 2011 and took effect on July 1, 2011. The CTS provides for a Canadian Local Toll (CLT) for deliveries within western Canada, as well as an International Joint Tariff (IJT) for crude oil shipments originating in western Canada, on the Canadian Mainline, and delivered into the United States, via the Lakehead System, and into eastern Canada. The IJT tolls are denominated in United States dollars. The IJT is designed to provide shippers on the Mainline System with a stable and competitive long-term toll, thereby preserving and enhancing throughput on both the Canadian Mainline and the Lakehead System. The CLT and the IJT are adjusted annually, on July 1 of each year, at a rate equal to 75% of the Canadian Gross Domestic Product at Market Price Index published by Statistics Canada.

Although the CTS has a 10-year term, it does not require shippers to commit to certain volumes. Shippers nominate volumes on a monthly basis and we allocate capacity to maximize the efficiency of the Canadian Mainline.

Local tolls for service on the Lakehead System are not affected by the CTS and continue to be established pursuant to the Lakehead System's existing toll agreements, as described below. Under the terms of the IJT agreement, the Canadian Mainline's share of the IJT relating to pipeline transportation of a batch from any western Canada receipt point to the United States border is equal to the IJT applicable to that batch's United States delivery point less the Lakehead System's local toll to that delivery point. This amount is referred to as the Canadian Mainline IJT Residual Benchmark Toll and is denominated in United States dollars.

**Lakehead System Local Tolls**

Transportation rates are governed by the FERC for deliveries from the Canada/United States border near Neche, North Dakota, Clearbrook, Minnesota and other points to principal delivery points on the Lakehead System. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC's index methodology and tariff agreements, the main components of which are index rates and the Facilities Surcharge Mechanism. Index rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing index rates, and is subject to annual adjustment on April 1 of each year.

**Mainline System Contracting**
On December 19, 2019, we submitted an application to the CER to implement contracting on our Mainline System. The application for contracted and uncommitted service included the associated terms, conditions and tolls of each service, which would be offered in an open season following approval by the CER. The tolls and services would replace the current CTS that is in place until June 30, 2021. If a replacement agreement is not in place by that time, the CTS tolls will continue on an interim basis.

For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Mainline System Contracting.*

**REGIONAL OIL SANDS SYSTEM**
The Regional Oil Sands System includes five intra-Alberta long-haul pipelines; the Athabasca Pipeline, Waupisoo Pipeline, Woodland Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and the Norlite Pipeline System (Norlite), as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray, Alberta. The Regional Oil Sands System also includes numerous laterals and related facilities which provide access for oil sands production to the system. The Regional Oil Sands System currently serves twelve producing oil sands projects.

The combined capacity of the intra-Alberta long-haul pipelines is approximately 930,000 bpd to Edmonton and 1,370,000 bpd into Hardisty, with Norlite providing approximately 218,000 bpd of diluent capacity into the Fort McMurray region. The Woodland Pipeline and Norlite are joint ventures, 50/50 between us and Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties, and 70/30 with Keyera Corp., respectively. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that include provisions for the recovery of some of the operating costs of this system.

**GULF COAST AND MID-CONTINENT**
Gulf Coast includes Seaway Crude Pipeline System (Seaway Pipeline), Flanagan South Pipeline (Flanagan South), Spearhead Pipeline and Gray Oak Pipeline, as well as the Mid-Continent System comprised of the Cushing Terminal.

**Seaway Pipeline**
We have a 50% interest in the 1,078-kilometer (670-mile) Seaway Pipeline, including the 805-kilometer (500-mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serve refineries in the Houston and Texas City areas. Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

The flow direction of Seaway Pipeline was reversed in 2012, enabling it to transport crude from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in early 2013, increasing capacity available to shippers from an initial 150,000 bpd to approximately 400,000 bpd, depending on crude slate. In late 2014, a second line, the Seaway Pipeline Twin, was placed into service to more than double the existing capacity to 950,000 bpd. Seaway Pipeline also includes a 161-kilometer (100-mile) pipeline from the Enterprise Crude Houston crude oil terminal in Houston, Texas to the Port Arthur/Beaumont, Texas refining center.

**Flanagan South**
Flanagan South is a 950-kilometer (590-mile), 36-inch diameter interstate crude oil pipeline that originates at our terminal at Flanagan, Illinois, a delivery point on the Lakehead System, and terminates in Cushing, Oklahoma. Flanagan South and associated pumping stations were completed in the fourth quarter of 2014. Flanagan South has a capacity of approximately 600,000 bpd.

**Spearhead Pipeline**
Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System, to Cushing, Oklahoma. The Spearhead pipeline was originally placed into service in 2006 and has a capacity of approximately 193,000 bpd.

**Gray Oak Pipeline**
The Gray Oak pipeline is a 1,368-kilometer (850-mile) crude oil system, which runs from the Permian Basin in West Texas to the United States gulf coast. The Gray Oak pipeline has an expected average annual capacity of 900,000 bpd and transports light crude oil. We have an effective 22.8% interest in the pipeline. Initial in-service for the pipeline commenced in November 2019 with full in-service expected in the second quarter of 2020.

**Mid-Continent System**
The Mid-Continent System is comprised of storage terminals at Cushing, Oklahoma (Cushing Terminal), consisting of over 80 individual storage tanks ranging in size from 78,000 to 570,000 barrels. Total storage shell capacity of Cushing Terminal is approximately 20 million barrels. A portion of the storage facilities are used for operational purposes, while the remainder are contracted to various crude oil market participants for their term storage requirements. Contract fees include fixed monthly storage fees, throughput fees for receiving and delivering crude to and from connecting pipelines and terminals, as well as blending fees.

**OTHER**
Other includes Southern Lights Pipeline, Express-Platte System, Bakken System and Feeder Pipelines and Other.

**Southern Lights Pipeline**
Southern Lights Pipeline is a single stream pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. This 180,000 bpd 16/18/20-inch diameter pipeline was placed into service in 2010. Both the Canadian portion of Southern Lights Pipeline (Southern Lights Canada) and the United States portion of Southern Lights Pipeline (Southern Lights US) receive tariff revenues under long-term contracts with committed shippers. Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity (18,000 bpd) assigned for shippers to ship uncommitted volumes.

**Express-Platte System**
The Express-Platte System consists of the Express pipeline and the Platte pipeline, and crude oil storage of approximately 5.6 million barrels. It is an approximate 2,736-kilometer (1,700-mile) crude oil transportation system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois. The Express pipeline carries crude oil to United States refining markets in the Rocky Mountains area, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with the Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the midwest. Express pipeline capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of Express pipeline capacity and all of the Platte pipeline capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

**Bakken System**
The Bakken System consists of the North Dakota System and the Bakken Pipeline System. The North Dakota System services the Bakken in North Dakota, and is comprised of a crude oil gathering and interstate pipeline transportation system. The gathering system provides delivery to Clearbrook, Minnesota for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The interstate portion of the system has both Unites States and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the United States portion of the North Dakota System are governed by the FERC and include a local tariff. The Canadian portion is categorized as a Group 2 pipeline, and as such, its tolls are regulated by the CER on a complaint basis. Tolls on the interstate pipeline system are based on long-term take-or-pay agreements with anchor shippers.

We have an effective 27.6% interest in the Bakken Pipeline System, which connects the Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast. The Bakken Pipeline System consists of the Dakota Access Pipeline from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline from Patoka, Illinois to Nederland, Texas. Current capacity is 570,000 bpd of crude oil with the potential to be expanded through additional pumping horsepower. The Bakken Pipeline System is anchored by long-term throughput commitments from a number of producers.

**Feeder Pipelines and Other**

Feeder Pipelines and Other includes a number of liquids storage assets and pipeline systems in Canada and the United States.

Key assets included in Feeder Pipelines and Other are the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude oil pipeline hub in western Canada and the Southern Access Extension (SAX) pipeline which originates in Flanagan, Illinois and delivers to Patoka, Illinois. On July 1, 2014, Marathon executed an agreement with us to become an owner (35%) in SAX, thereby forming the Illinois Extension Pipeline Company (IEPC). We have a 65% ownership in IEPC. SAX was placed into service in December 2015 with the majority of its capacity commercially secured under long-term take-or-pay contracts with shippers.

Feeder Pipelines and Other also includes Patoka Storage, the Toledo pipeline system and the Norman Wells (NW) System. Patoka Storage is comprised of four storage tanks with 480,000 barrels of shell capacity located in Patoka, Illinois. The Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta and has a cost-of-service rate structure based on established terms with shippers.

**COMPETITION**

Other competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada, the United States and internationally represent competition to our liquids pipelines network. Competition amongst existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets.

Competition also arises from proposed pipelines that seek to access markets currently served by our liquids pipelines, such as proposed projects to the Gulf Coast and from proposed projects enhancing infrastructure in the Alberta regional oil sands market. The Mid-Continent and Bakken systems also face competition from existing pipelines, proposed future pipelines and existing and alternative gathering facilities. Competition for storage facilities in the United States includes large integrated oil companies and other midstream energy partnerships. Additionally, volatile crude price differentials and insufficient pipeline capacity on either our or competitors' pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently serviced by pipelines.

We believe that our liquids pipelines continue to provide attractive options to producers in the Western Canadian Sedimentary Basin (WCSB) and North Dakota due to our competitive tolls and flexibility through our multiple delivery and storage points. We also employ long-term agreements with shippers, which mitigates competition risk by ensuring consistent supply to our liquids pipelines network. Our current complement of growth projects to expand market access and to enhance capacity on our pipeline system are expected to provide shippers reliable and long-term competitive solutions for liquids transportation. We have a proven track record of successfully executing projects to meet the needs of our customers and our existing right-of-way for the Mainline System also provides a competitive advantage as it can be difficult and costly to obtain rights-of-way for new pipelines traversing new areas. In addition, we are currently pursuing the offering of contracted service on the Mainline System which would further contribute to mitigating competition risk.

**SUPPLY AND DEMAND**

We have an established and successful history of being the largest transporter of crude oil to the United States, the world's largest market for crude oil. While United States demand for Canadian crude oil production will support the use of our infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and we have a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets.

The International Energy Agency 2019 World Energy Outlook indicated that upstream investment in 2019 demonstrated a continued upward trend. International prices weakened in 2019 compared to the previous year with United States tensions with China and continued supply growth outside of the Organization of Petroleum Exporting Countries (OPEC). World oil demand rose marginally over the year however, supply grew at a faster pace. The United States continued to increase its productive capacity, supported by its crude oil exports growing to over 3 million bpd in September 2019.

In western Canada, lack of export pipeline capacity resulted in the rapid buildup of inventories and discounts to the price of western Canadian crude. Western Canadian Select discounts peaked at over US $50 per barrel against West Texas Intermediate (WTI) in October 2018. This, in turn, resulted in the Alberta Government approving a plan to lease 4,400 rail cars to add approximately 120,000 bpd of rail export capacity for the industry by the end of 2020 and the adoption of a production curtailment policy directing the industry in the province to shut in 325,000 bpd starting January 1, 2019. The aim of this policy was to both draw down inventories by approximately 20 million barrels and return crude discounts to more historical norms. The policy calls for curtailment levels to be reduced as inventory levels decline and new pipeline and rail capacity come on line. Western Canadian crude prices responded almost immediately upon the release of the curtailment adoption notice, with discounts narrowing to approximately US$10 per barrel. The discount at this level would imply that rail is not financially attractive, and hence frustrating the government's efforts to draw down inventories. Rail movements dropped by more than 200,000 bpd between December 2018 and February 2019 as differentials were narrow enough that it was not economic to ship crude by rail in the first quarter of 2019. The differentials widened to above $10 per barrel in subsequent quarters to support the return of crude by rail. Throughout the year, the curtailment levels declined to a year end restriction of 75,000 bpd with an expectation that Alberta production volumes will continue to increase in 2020.

Notwithstanding the current price environment and Alberta policies, our Mainline System has thus far continued to be highly utilized. Mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record deliveries of 2.845 million bpd in December 2019, slightly higher than our previous record in July 2019. The Mainline System continues to be subject to apportionment, as nominated volumes currently exceed capacity on portions of the system. The impact of a low crude oil price environment on the financial performance of our Liquids Pipelines business is expected to be relatively modest given the cost effectiveness of our Mainline toll and commercial arrangements which underpin many of the pipelines providing a significant measure of protection against volume fluctuations. Our Mainline System is well positioned to continue to provide safe and efficient transportation which will enable western Canadian and Bakken production to reach attractive markets in the United States and eastern Canada at a competitive cost relative to other alternatives.

The fundamentals of oil sands production and discounts for western Canadian crude have caused some sponsors to reconsider the timing of future projects. While recently updated forecasts continue to reflect long-term supply growth from the WCSB, the projected pace of growth is slower than previous forecasts as companies continue to assess the viability of capital investments in light of the current price environment and ongoing uncertainty with respect to the timing and completion of new pipeline systems proposed by our competitors.

Over the long term, continued growth in global energy consumption is expected to be primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), mainly in India and China. In North America, demand growth for transportation fuels is expected to moderate due to vehicle fuel efficiencies and increasing sales of electric vehicles. Accordingly, there is a strategic opportunity to establish tide-water export facilities to service North American producers wanting access to global markets.

Global crude oil production is expected to continue to grow through 2035, primarily in North America, Brazil and OPEC. Growth in supply from OPEC is partly due to the expected recovery of Iraqi and Libyan production. Over the longer term, North American production from tight oil plays is expected to grow as technology continues to improve well productivity and efficiencies. The pace of growth in North America and level of investment in the WCSB could be tempered in future years by a number of factors including a sustained period of low crude oil prices and corresponding production decisions by OPEC, increasing environmental regulation and prolonged approval processes for new pipelines with access to tide-water for export or to United States markets.

In recent years, the combination of relatively flat domestic demand, growing supply and long lead time to build pipeline infrastructure led to a fundamental change in the North American crude oil landscape. The inability to move increasing inland supply to markets resulted in a divergence between WTI and world pricing, resulting in lower netbacks for North American producers. The impact of price differentials has been even more pronounced for western Canadian producers as insufficient pipeline infrastructure resulted in a further discounting of Alberta crude relative to WTI. Canadian pipeline export capacity is expected to remain fully utilized, resulting in continued apportionment on our Mainline System and incremental production utilizing non-pipeline transportation services (e.g. rail and trucks) until such time as sufficient pipeline capacity is made available. Over the longer term, however, we believe pipelines will continue to be the most reliable, safe and cost-effective means of transportation.

Our role in helping to address the evolving supply and demand fundamentals and alleviating price discounts for producers and supply costs to refiners is through optimization of throughput on our existing liquids pipelines systems and through investment in new pipelines and related infrastructure to provide expanded transportation capacity and sustainable connectivity to alternative markets. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

# GAS TRANSMISSION AND MIDSTREAM

Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the United States, including US Gas Transmission, Canadian Gas Transmission, US Midstream and other assets.

**US GAS TRANSMISSION**

US Gas Transmission includes ownership interests in Texas Eastern, Algonquin, M&N U.S., East Tennessee, Gulfstream, Sabal Trail Transmission (Sabal Trail), NEXUS, Valley Crossing, Southeast Supply Header (SESH), Vector Pipeline L.P. (Vector) and certain other gas pipeline and storage assets. The US Gas Transmission business primarily provides transmission and storage of natural gas through interstate pipeline systems for customers in various regions of the northeastern, southern and midwestern United States.

The Texas Eastern natural gas transmission system extends approximately 2,735-kilometers (1,700-miles) from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system consists of approximately 14,597-kilometers (9,070-miles) of pipeline and associated compressor stations. Texas Eastern is also connected to four affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business.

The Algonquin natural gas transmission system connects with Texas Eastern’s facilities in New Jersey and extends approximately 402-kilometers (250-miles) through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N U.S. The system consists of approximately 1,835-kilometers (1,140-miles) of pipeline with associated compressor stations. We have a 92% interest in the Algonquin natural gas transmission system.

M&N U.S. is an approximately 563-kilometer (350-mile) mainline interstate natural gas transmission system, including associated compressor stations, which extends from northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system (M&N Canada) (see *Gas Transmission and Midstream - Canadian Gas Transmission*). We have a 78% interest in M&N U.S.

East Tennessee’s natural gas transmission system crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,470-kilometers (1,535-miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a LNG storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

Gulfstream is an approximately 1,199-kilometer (745-mile) interstate natural gas transmission system with associated compressor stations, operated jointly with The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. We have a 50% interest in Gulfstream.

Sabal Trail is an approximately 829-kilometer (515-mile) pipeline that provides firm natural gas transportation to Florida Power & Light Company for its power generation needs and to a Duke Energy Florida natural gas plant. Facilities include a pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds approximately 1.1 billion cubic feet per day (bcf/d) of new capacity enabling the access of onshore shale gas supplies once approved future expansions are completed. We have a 50% interest in Sabal Trail.

NEXUS is an approximately 410-kilometer (255-mile) interstate natural gas transmission system with associated compressor stations. NEXUS transports natural gas from our Texas Eastern system in Ohio to our Vector interstate pipeline in Michigan, with capacity of approximately 1.5 bcf/d. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America, located in southwestern Ontario adjacent to the Greater Toronto Area. We have a 50% interest in NEXUS.

Valley Crossing is an approximately 274-kilometer (170-mile) intrastate natural gas transmission system, with associated compressor stations. The pipeline infrastructure is located in Texas and provides market access of up to 2.6 bcf/d to the Comisión Federal de Electricidad, Mexico's state-owned utility.

SESH is an approximately 467-kilometer (290-mile) natural gas transmission system with associated compressor stations, owned and operated jointly with Enable Gas Transmission, LLC. SESH extends from the Perryville Hub in northeastern Louisiana where the shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities. We have a 50% interest in SESH.

Vector is a 560-kilometer (348-mile) pipeline that transports 1.3 bcf/d of natural gas from Joliet, Illinois in the Chicago area to parts of Indiana, Michigan and Ontario. We have a 60% interest in Vector.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines or injected or withdrawn from our storage facilities, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also available where customers can use capacity if it exists at the time of the request and are generally at a higher toll than long-term contracted rates. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers' needs.

**CANADIAN GAS TRANSMISSION**

On July 4, 2018, we entered into agreements to sell our British Columbia Field Services business to Brookfield Infrastructure Partners L.P. and its institutional partners. Separate agreements were entered into for those facilities governed by provincial regulations and those governed by federal regulations. On October 1, 2018, we closed the sale of the provincially regulated facilities and on December 31, 2019, we closed the sale of the federally regulated facilities. For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Asset Monetization* and *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions.*

On May 28, 2019, we completed the sale of our federally regulated natural gas gathering and processing assets in the Grizzly Valley area of British Columbia to Sukunka Natural Resources Inc., a subsidiary of Canadian Natural Resources Limited.

Canadian Gas Transmission still includes British Columbia Pipeline, M&N Canada, Alliance Pipeline and certain other midstream gas pipelines, gathering, processing and storage assets.

British Columbia Pipeline has approximately 2,900-kilometers (1,800-miles) of transmission pipeline in British Columbia and Alberta, as well as associated mainline compressor stations and provides fee-for-service based natural gas transmission services.

M&N Canada is an approximately 885-kilometer (550-mile) interprovincial natural gas transmission mainline system which extends from Goldboro, Nova Scotia to the United States border near Baileyville, Maine. M&N Canada is connected to M&N U.S. For further information, refer to *Gas Transmission and Midstream - US Gas Transmission*. We have a 78% interest in M&N Canada.

Alliance Pipeline is a 3,000-kilometer (1,864-mile) integrated, high-pressure natural gas transmission pipeline and approximately 860-kilometers (534-miles) of lateral pipelines and related infrastructure. It transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to the Alliance Chicago gas exchange hub downstream of the Aux Sable NGL extraction and fractionation plant at Channahon, Illinois. The majority of transportation services provided by Alliance Pipeline are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline. Alliance Pipeline also provides interruptible transmission services where customers can use capacity if it is available at the time of request. We have a 50% interest in Alliance Pipeline.

The majority of transportation services provided by Canadian Gas Transmission are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. Canadian Gas Transmission also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

**US MIDSTREAM**

US Midstream includes a 42.7% interest in each of Aux Sable Liquid Products LP and Aux Sable Midstream LLC, and a 50% interest in Aux Sable Canada LP (collectively, Aux Sable). Aux Sable Liquid Products LP owns and operates an NGL extraction and fractionation plant at Channahon, Illinois, outside Chicago, near the terminus of Alliance Pipeline. Aux Sable also owns facilities upstream of Alliance Pipeline that facilitate deliveries of liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned and operated by Aux Sable Midstream US; and Aux Sable Canada's interests in the Montney area of British Columbia, comprising the Septimus Pipeline and the Septimus and Wilder Gas Plants.

US Midstream also includes a 50% investment in DCP Midstream, LLC (DCP Midstream), which indirectly owns approximately 57% of DCP Midstream, LP, including limited partner and general partner interests. DCP Midstream, LP is a master limited partnership, with a diversified portfolio of assets, engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs; and recovering and selling condensate. DCP Midstream, LP owns and operates more than 49 plants and approximately 99,780-kilometers (62,000-miles) of natural gas and natural gas liquids pipelines, with operations in 17 states across major producing regions.

**OTHER**

Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 active natural gas gathering and FERC regulated transmission pipelines and four active oil pipelines. These pipelines are located in four major corridors in the Gulf of Mexico, extending to deepwater developments, and include almost 2,100-kilometers (1,300-miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d.

**COMPETITION**

Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The flow pattern of natural gas is changing across North America due to emerging supply sources and evolving demand centers, which creates competition for growth opportunities. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Competition exists in all of the markets our businesses serve. Competitors include interstate and intrastate pipelines or their affiliates and other midstream businesses that transport, gather, treat, process and market natural gas or NGLs. Because pipelines are generally the most efficient mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies.

**SUPPLY AND DEMAND**

Our gas transmission assets make up one of the largest natural gas transportation networks in North America, driving connectivity between prolific supply basins and major demand centers within the continent. Our systems have been integral to the transition in natural gas fundamentals over the last decade, and will continue to play a part as the energy landscape evolves. Shifts in production and consumption, both domestic and foreign, will require that we continue to serve as a critical link between markets.

In 2010, natural gas production in each of the Appalachian and Permian basins were less than 5.0 bcf/d each. Today, these regions produce more than 50.0 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling has increased the supply of low-cost natural gas. As well, there has been and continues to be a corresponding increase in demand for our natural gas infrastructure in North America. Through a series of expansions and reversals on our core systems, combined with the execution of greenfield projects and strategic acquisitions, we have been able to meet the needs of producers and consumers alike. Our US Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply starved northeast markets. Our asset base now has the capability to transport diverse supply to the northeast, southeast, midwest, and gulf coast markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady growth. Natural gas demand in the northeast is expected to grow by 2.5 bcf/d through 2040, driven by continued commercial and residential load growth. Natural gas leads the fuel mix of the Independent System Operator New England market at more than 40 percent. The bidirectional capabilities offered by our system allow us to deliver both domestic and imported supplies to our regional customers, 75 percent of whom are end users with a contract renewal rate of over 99 percent. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

Demand for natural gas in the southeast region is forecast to increase by 4.0 bcf/d through 2040. Generating capacity in Florida is expected to grow 15 percent by 2026, the majority of which is projected to be natural gas-fired. The southeast market is linked to multiple, highly liquid supply pools that include the Marcellus and Utica shale developments, offering consistent supply and stable pricing to a growing population of end-use customers across our multiple systems under long term, utility-like arrangements.

With connectivity to Appalachian and western Canadian supply through our systems, the midwest market has access to two of the lowest cost gas producing regions on the continent. As demand in the region is expected to continue to grow by approximately 3.0 bcf/d over the next two decades, maintaining this link will remain important. Flexibility in supply for this market is especially critical to maintaining liquidity and price stability as natural gas continues to replace coal-fired generation.

Gulf coast demand growth is being driven by an ongoing wave of gas-intensive petrochemical facilities which are now starting to enter service, along with power generation, an increase in the volume of LNG exports and additional pipeline exports to Mexico. Demand in the region is anticipated to grow by more than 19.0 bcf/d through 2040. The gulf coast market has been the beneficiary of low cost capacity on our assets as the relationship between supply and market centers has shifted. Such cost effective capacity is difficult to access or replicate, offering existing shippers and transporters stability of capacity and utilization. Tide water market access and proximity to Mexico continue to make this region a platform of global trade as pipeline, LNG and Liquefied Petroleum Gas (LPG) exports see strong growth. The United States exported approximately 4.0 bcf/d of natural gas from the gulf coast region at the end of 2019 with an export capacity of approximately 10.0 bcf/d scheduled to be in service by 2021.

Despite there being strong growth in both supply and demand in the United States, a lack of adequate transportation capacity has placed downward pressure on local natural gas pricing. The Appalachian Basin has seen price differentials of $1.00 to $2.00 per million British Thermal Units (MMBtu) relative to Henry Hub in the gulf coast over the last few years. Unlike the dry gas production of the Marcellus, natural gas production growth in the Permian Basin is a result of robust crude oil production taking place in the region. Associated gas supplies from the region increased by approximately 10.0 bcf/d over the past two years and growth is forecasted to continue for the next decade. Until new natural gas transportation capacity begins to come online through the early 2020s, the natural gas prices in the region will continue to remain low relative to other producing regions.

Western Canada is experiencing a similar phenomenon to that of the Permian, with the local markets experiencing very low or even negative prices for natural gas as transportation bottlenecks continue. One of the few vital links to demand centers in the pacific northwest are our own systems in the region which operate near full capacity. As demand for supply out of the WCSB continues to grow, driven largely by NGL production and local oil sands production, the need for new natural gas and NGL infrastructure will continue to rise.

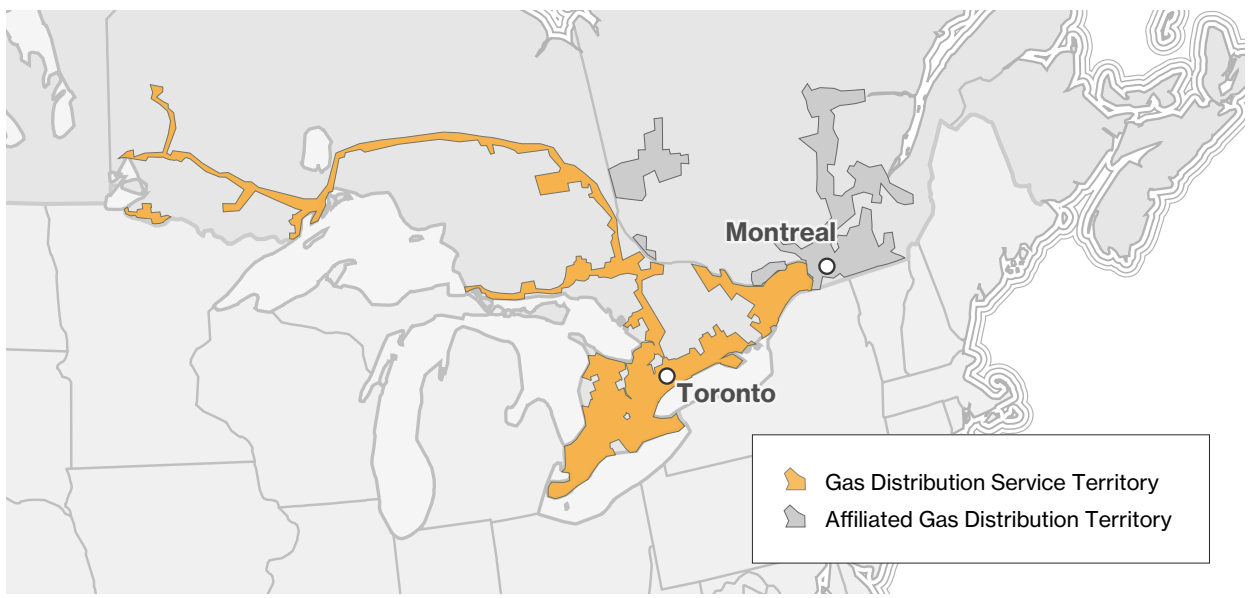
Global energy demand is expected to increase approximately 25 percent by 2040, according to the International Energy Agency, driven primarily by economic growth in non-OECD countries. Natural gas will play an important role in meeting this energy demand as gas consumption is anticipated to grow by approximately 40 percent during this period as one of the world's fastest growing energy sources. North American exports will play a significant part in meeting global demand, underscoring the ability of our assets to remain highly utilized by shippers, and highlighting the need for incremental transportation solutions across North America. In response to these global fundamentals, we believe we are well positioned to provide value-added solutions to shippers. We are responding to the need for regional infrastructure with additional investments in Canadian and United States gas transportation facilities. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

# GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec and an investment in Noverco Inc. (Noverco).

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) were amalgamated on January 1, 2019. The amalgamated company has continued as Enbridge Gas. The amalgamation creates the single largest natural gas utility in North America in terms of send-out volumes, and third largest in terms of number of customers. We expect that the ongoing amalgamation will drive efficiencies and synergies, leverage greater supply-chain strength, create new opportunities for growth and form a stronger platform to deliver strong, provide predictable returns to shareholders and superior value and service to customers.

On October 1, 2019, we closed the sale of Enbridge Gas New Brunswick Inc. (EGNB) to Liberty Utilities (Canada) LP and on November 1, 2019, we closed the sale of St. Lawrence Gas Company, Inc. to Liberty Utilities Co., both wholly-owned subsidiaries of Algonquin Power & Utilities Corp. For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Asset Monetization* and *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions.*




**ENBRIDGE GAS**

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services and has been in operation for approximately 170 years. Enbridge Gas serves approximately 3.8 million residential, commercial and industrial customers across Ontario.

There are three principal interrelated aspects of the natural gas distribution business in which Enbridge Gas is directly involved: Distribution, Transportation and Storage.

**Distribution**
Enbridge Gas' principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis, without a specific fixed-term or fixed-price contract. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, Enbridge Gas is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at Enbridge Gas' option to meet seasonal or peak demands. The Ontario Energy Board (OEB) approves rates for both contract and general services. The distribution system consists of approximately 151,000-kilometers (93,800-miles) of pipelines that carry natural gas from the point of local supply to customers.

Customers have a choice with respect to natural gas supply. Customers may purchase and deliver their own natural gas into Enbridge Gas' distribution system or alternatively they may choose a system supply option, whereby customers purchase natural gas from Enbridge Gas' supply portfolio. To acquire the necessary volume of natural gas to serve its customers, Enbridge Gas maintains a diversified natural gas supply portfolio, acquiring supplies on a delivered basis in Ontario, as well as acquiring supply from multiple supply basins across North America.

**Transportation**
Enbridge Gas contracts for firm transportation service, primarily with TransCanada Pipelines Limited (TransCanada), Vector Pipeline Limited Partnership and NEXUS Gas Transmission Pipeline, to meet its annual natural gas supply requirements. The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows Enbridge Gas flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. Enbridge Gas forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

In addition to contracting for transportation service, Enbridge Gas offers firm and interruptible transportation services on its own Dawn-Parkway pipeline system. Enbridge Gas' transmission system consists of approximately 5,500-kilometers (3,418-miles) of high-pressure pipeline, five mainline compressor stations and has an effective peak daily demand capacity of 7.6 bcf/d. Enbridge Gas' transmission system also links an extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub (collectively, Dawn) to major Canadian and United States markets, and forms an important link in moving natural gas from western Canada and United States supply basins to central Canadian and northeastern United States markets.

As the supply of natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the northeastern United States. Enbridge Gas delivered 1,860 Bcf of gas through its distribution and transmission system in 2019. A substantial amount of Enbridge Gas' transportation revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately 13 years and the longest remaining contract term being 21 years.

**Storage**
Enbridge Gas' business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits Enbridge Gas to take delivery of natural gas on favorable terms during off peak summer periods for subsequent use during the winter heating season. This practice permits Enbridge Gas to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to Enbridge Gas' franchise areas.

Enbridge Gas' storage facility at Dawn is located in southwestern Ontario, and has a total working capacity of approximately 272 bcf in 34 underground facilities located in depleted gas fields. Dawn is the largest integrated underground storage facility in Canada and one of the largest in North America. Approximately 181 bcf, at their respective current heat values, of the total working capacity is available to Enbridge Gas for utility operations. Enbridge Gas also has storage contracts with third parties for 17 bcf of storage capacity.

Dawn offers customers an important link in the movement of natural gas from western Canadian and United States supply basins to markets in central Canada and the northeast United States. Dawn's configuration provides flexibility for injections, withdrawals and cycling. Customers can purchase both firm and interruptible storage services at Dawn. Dawn offers customers a wide range of market choices and options with easy access to upstream and downstream markets. During 2019, Dawn provided services such as storage, balancing, gas loans, transport, exchange and peaking services to over 200 counterparties.

A substantial amount of Enbridge Gas' storage revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately four years and the longest remaining contract term being 17 years.

**NOVERCO**

Noverco is a holding company that wholly-owns Énergir, LP (Energir), formerly known as Gaz Metro Limited Partnership, a natural gas distribution company operating in the province of Quebec, with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the Province of Québec and the State of Vermont. Energir serves approximately 525,000 residential and industrial customers and is regulated by the Québec Régie de l'énergie and the Vermont Public Utility Commission. Noverco also holds, directly and indirectly, an investment in our common shares. We own an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in its preferred shares.

**GAZIFÈRE**

We wholly own Gazifère, a natural gas distribution company that serves approximately 43,000 customers in western Québec, a market not served by Energir. Gazifère is regulated by the Québec Régie de l'énergie.

**COMPETITON**

Enbridge Gas' distribution system is regulated by the OEB and is subject to regulation in a number of areas, including rates. Enbridge Gas is not generally subject to third-party competition within its distribution franchise areas.

Enbridge Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels and other factors.

**SUPPLY AND DEMAND**

We expect that demand for natural gas in North America will continue to see low annual growth over the long term with continued growth in peak day demands. Some modest growth driven by low natural gas prices is expected to continue given the significant price advantage relative to alternate energy options, with specific interest coming from communities that are not currently serviced by natural gas. Enbridge Gas continues to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through various demand side management programs offered across all markets. We expect demand for natural gas in the greater Toronto metropolitan area to continue to grow due to favorable population growth supplemented by the expansion of other communities served by our system.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics including a robust supply environment. In recent years, the robust North American gas supply balance, due mainly to the development of shale gas volumes including the Alberta, British Columbia, Marcellus and Utica shale areas, has resulted in lower commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined based on the difference in value between winter and summer natural gas prices. Storage values have been relatively stable to slightly rising as the North American natural gas supply and demand slowly returned to a more balanced position.

# RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario, and Québec and in the states of Colorado, Texas, Indiana and West Virginia. In Europe, Enbridge holds equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom and Germany, as well as in several projects under active development in France. Further, we are pursuing new European development opportunities through Maple Power Ltd., a joint venture in which we hold a 50% interest.

Combined Renewable Power Generation investments represent approximately 1,991 MW of net generation capacity. Of this amount, approximately:

- 1,392 MW is generated by North American wind facilities;
- 255 MW is generated by European offshore wind facilities;
- 240 MW is generated by the Saint-Nazaire Offshore Wind project, currently under construction; and
- 78 MW is generated by North American solar facilities.

The vast majority of the power produced from these wind facilities is sold under long-term power purchase agreements.

Renewable Power Generation includes the Montana-Alberta Tie-Line (MATL), a 300 MW transmission line which runs from Great Falls, Montana to Lethbridge, Alberta. In the fourth quarter of 2019, we committed to a plan to sell the MATL transmission assets. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

**JOINT VENTURES / EQUITY INVESTMENTS**

Effective August 1, 2018, the investments in the Canadian renewable assets and two of the United States renewable assets are held within a joint venture in which we maintain a 51% interest and continue to manage, operate, and provide administrative support.

We also own interests in European offshore wind facilities through the following joint ventures:

- a 24.9% interest in Rampion Offshore, located in the United Kingdom, which went into service April 2018;
- a 25% interest in Hohe See Offshore and its subsequent expansion, located in Germany, which went into service October 2019 and January 2020, respectively; and
- a 50% interest in the Saint-Nazaire Offshore Wind project, located in France, that is currently under construction.

**COMPETITION**

Our Renewable Power Generation assets operate in the North American and European power markets, which are subject to competition and supply and demand fundamentals for power in the jurisdictions in which they operate. The majority of revenue is generated pursuant to long-term power purchase agreements or has been substantially hedged. As such, the financial performance is not significantly impacted by fluctuating power prices arising from supply/demand imbalances or the actions of competing facilities during the term of the applicable contracts. However, the renewable energy sector includes large utilities, small independent power producers and private equity investors, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts expire.

To grow in an environment of heightened competition, we strategically seek opportunities to collaborate with well-established renewable power developers and financial partners and to target regions with commercial constructs consistent with our low risk business model. In addition, we bring to bear the expertise of completing and delivering large scale infrastructure projects.

**SUPPLY AND DEMAND**

The renewable power generation network in North America is expected to undergo significant growth over the next 20 years due to the replacement of older sources of electricity generation. On the demand side, North American economic growth over the longer term is expected to drive growing electricity demand, although continued efficiency gains are expected to make the economy less energy-intensive and temper demand growth. On the supply side, legislation is expected to accelerate the retirement of aging coal-fired generation plants, resulting in a requirement for significant new generation capacity and extending project lives and/or power purchase agreements of preferred technologies. While coal and nuclear facilities will continue to be core components of power generation in North America, gas-fired and renewable energy facilities, including biomass, hydro, solar and wind (the latter of which make up the bulk of our assets), are expected to be the preferred sources to replace coal-fired generation due to their lower carbon intensities. In addition, changes in the administration in the jurisdictions within which we operate, or in societal views, could result in a significant policy shift or pressure to accelerate low carbon transition.

In the near-term, uncertainty over the availability of tax or other government incentives in various jurisdictions, the ability to secure long-term power purchase agreements through government or investor-owned power authorities and low market prices of electricity may hinder the pace of future new renewable capacity development. However, continued improvement in technology and manufacturing capacity in the past few years has reduced capital costs and improved yield factors associated with renewable energy generation. These positive developments are expected to render renewable energy more competitive and support ongoing investment over the long-term, regardless of available incentives. Related growth opportunities could include repowering projects to increase output from and extend project-life of our existing facilities.

In Europe, the renewable energy outlook is positive, especially for offshore wind in countries with long coastlines and densely populated areas. According to the European Wind Energy Association, by 2030, wind energy capacity in Europe is expected to be 320 Gigawatts (GW), including 66 GW of offshore capacity as compared to 18.5 GW at the end of 2018. There is also wide public support for carbon reduction targets and broader adoption of renewable generation across all governmental levels. We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France, and Germany to meet the growing demand.

## ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems. Energy Services provides energy marketing services to North American refiners, producers, and other customers.

Energy Services is primarily focused on servicing customers across the value chain and capturing value from quality, time, and location price differentials when opportunities arise. To execute these strategies, Energy Services transports and stores on both Enbridge-owned and third party assets using a combination of contracted long-term and short-term pipeline, storage tank, railcar, and truck capacity agreements.

**COMPETITION**

Energy Services' earnings are primarily generated from arbitrage opportunities which, by their nature, can be replicated by competitors. An increase in market participants entering into similar arbitrage strategies could have an impact on our earnings. Efforts to mitigate competition risk include diversification of the marketing business by transacting at the majority of major hubs in North America and establishing long-term relationships with clients and pipelines.

## ELIMINATIONS AND OTHER

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements, which are not allocated to business segments. Eliminations and Other also includes new business development activities and corporate investments.

## OPERATIONAL, ENVIRONMENTAL AND ECONOMIC REGULATION

**LIQUIDS PIPELINES**

**Operational Regulation**

We are subject to numerous operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

In the United States, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation (DOT). These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines and determine the pressures at which our pipelines can operate.

PHMSA has designed an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. Additionally, PHMSA has established standards for storage facilities. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failure or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, earnings, cash flows and financial condition.

In Canada, our pipeline operations are subject to pipeline safety regulations overseen by the CER or provincial regulators. Applicable legislation and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the United States, several legislative changes addressing pipeline safety in Canada have recently been enacted. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the CER to impose administrative monetary penalties for non-compliance with the regulatory regime it administers, as well as to impose financial requirements for future abandonment and major pipeline releases.

**Environmental Regulation**

We are also subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits and other approvals.

In particular, in the United States, compliance with major Clean Air Act regulatory programs is likely to cause us to incur significant capital expenditures to obtain permits, evaluate off-site impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some states in which we operate are implementing new emissions limits to comply with 2008 ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered even further from 75 parts per billion (ppb) to 70 ppb, which may require states to implement additional emissions regulations. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs may significantly increase our operating costs compared to historical levels.

In the United States, climate change action is evolving at state, regional and federal levels. The Supreme Court decision in Massachusetts v. Environmental Protection Agency in 2007 established that GHG emissions were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities, but are not generally subject to limits on emissions of GHGs. In addition, a number of states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

For its part, Canada has reaffirmed its strong preference for a harmonized approach with that of the United States. In 2019, the Government of Canada implemented a federal system of carbon pricing. The pricing applies to provinces and territories that are not in compliance with the federal requirements.

Due to the speculative outlook regarding any United States federal and state policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

**Economic Regulation**

Our liquids pipelines also face economic regulation risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The Mainline System and other liquids pipelines are subject to the actions of various regulators, including the CER and FERC, with respect to the tariffs and tolls of those operations. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on our revenues and earnings. Delays in regulatory approvals on projects such as our U.S. L3R Program, could result in cost escalations and construction delays, which also negatively impact our operations.

**GAS TRANSMISSION AND MIDSTREAM**

**Operational Regulation**

The span of regulation risks that apply to the Liquids Pipeline business as described above under *Liquids Pipelines* also applies to the Gas Transmission and Midstream business. Most of our United States gas transmission operations are regulated by the FERC. The FERC regulates natural gas transmission in United States interstate commerce including the establishment of rates for services. The FERC also regulates the construction of United States interstate natural gas pipelines and storage facilities, including the extension, enlargement and abandonment of facilities. In addition, certain operations are subject to oversight by state regulatory commissions. To the extent that the natural gas intrastate pipelines that transport or store natural gas in interstate commerce provide services under Section 311 of the Natural Gas Policy Act of 1978, they are subject to FERC regulations. The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission and storage companies, which remain subject to the FERC's jurisdiction. These initiatives may also affect certain transmission of gas by intrastate pipelines. We reached an agreement with Texas Eastern shippers and filed a Stipulation and Agreement with the FERC on October 28, 2019. We expect a decision from the FERC in the second quarter of 2020, upon which we will begin recognizing updated rates within our results of operations.

Our operations are subject to the jurisdiction of the Environmental Protection Agency and various other federal, state and local environmental agencies. Our United States interstate natural gas pipelines and certain of DCP Midstream's gathering and transmission pipelines are also subject to the regulations of the DOT concerning pipeline safety.

The intrastate natural gas and NGL pipelines owned by us and DCP Midstream are subject to state regulation. DCP Midstream's interstate NGL transportation pipelines are subject to FERC regulation. The natural gas gathering and processing activities of DCP Midstream are not subject to FERC regulation.

Our Canadian operations are governed by various federal and provincial agencies with respect to pipeline safety, including the CER, the Transportation Safety Board and the Ontario Technical Standards and Safety Authority.

Our Canadian natural gas transmission operations are subject to regulation by the CER or the provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, the terms and conditions of service, the construction of additional facilities and acquisitions. We are in the process of negotiating a rate settlement agreement with our British Columbia Pipeline shippers. Since the expiration of our previous Settlement Agreement at the end of 2019, we have been charging interim rates as approved by the CER.

**GAS DISTRIBUTION AND STORAGE**

**Operational Regulation**

Our gas distribution and storage utility operations are regulated by the OEB and the Québec Régie de l'énergie, among others. Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environments in which we operate. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or amounts that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

We seek to mitigate operational regulation risk. We retain dedicated professional staff and maintain strong relationships with customers, intervenors and regulators. This strong regulatory relationship continued in 2019 following the OEB's Decision and Order to approve Enbridge Gas' application for 2019 rates. The Decision and Order approved an effective date for base rates of April 1, 2019, and the inclusion of incremental capital module amounts to allow for the recovery of incremental capital investments.

Enbridge Gas' distribution rates, beginning in 2019, are set under a five-year incentive regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material aggregate incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers, any earnings in excess of 150 basis points over the annual OEB approved return on equity (ROE).

**Environmental Regulation**
Our workers, operations and facilities are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. Environmental legislation primarily includes regulation of discharges to air, land and water; management and disposal of hazardous waste; the assessment and management of contaminated sites; and the reporting and reduction of GHG emissions.

Gas distribution system operation, as with any industrial operation, has the potential risk of abnormal or emergency conditions, or other unplanned events that could result in spills or emissions in excess of permitted levels. These events could result in injuries to workers or the public, adverse impacts to the environment in which we operate within, property damage or regulatory violations including order and fines. We could also incur future liability for soil and groundwater contamination associated with past and present site activities.

In addition to gas distribution, we also operate storage facilities and small oil and brine productions in southwestern Ontario. Environmental risk associated with these facilities is the potential for unplanned releases. In the event of a release, remediation of the affected area would be required. There would also be potential for fines, orders or charges under environmental legislation, and potential third-party liability claims by any affected land owners.

The gas distribution system and our other operations must maintain environmental approvals and permits from regulators to operate. As a result, these assets and facilities are subject to periodic inspections and/or audits. Annual reports, such as the Annual Written Summary Report are submitted to the Ontario Ministry of Environment, Conservation and Parks (MECP) and other regulators to demonstrate we are in good standing with our Environmental Compliance Approvals. Failure to maintain regulatory compliance could result in operational interruptions, fines, and/or orders for additional pollution control technology or environmental mitigation. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals has increased.

As with previous years, in 2019, we reported GHG emissions to Environment and Climate Change Canada (ECCC), the Ontario MECP, and a number of voluntary reporting programs. Emissions from Ontario combustion sources were verified in detail by a third-party accredited verifier with no material discrepancies found. Additionally, operational emissions from venting, fugitive and natural gas distribution emissions were reported to the MECP starting in 2017 in accordance with Ontario regulations.

Enbridge Gas utilizes emissions data management processes and systems to help with the data capture and mandatory and voluntary reporting needs. Quantification methodologies and emission factors will continually be updated in the system as required. Enbridge Gas continues to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions.

In October 2018, the federal government confirmed that Ontario is subject to the federal government's carbon pricing program, otherwise known as the Federal Carbon Pricing Backstop Program. This program consists of two components: an output-based pricing system (OBPS) and carbon charge levied on fossil fuels, including natural gas.

The OBPS component began on January 1, 2019. Under OBPS, a registered facility will have a facility-specific annual emission limit which is based on the relevant output-based standard for its level of production. Enbridge Gas has registered with ECCC as an emitter in the OBPS program and will have an annual compliance obligation associated with its natural gas pipeline transmission system. Annually, Enbridge Gas is required to report its emissions covered under the OBPS, have the emissions report verified by an accredited third-party verifier and remit payment for any emissions that exceed the facility-specific emission limit.

The federal carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter ($m^3$) of natural gas, and is applicable to the majority of customers. Enbridge Gas has registered as a natural gas distributor with the Canadian Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 by 1.96 cents/$m^3$ up to 9.79 cents/$m^3$ in 2022.

## EMPLOYEES

We had approximately 11,300 employees as at December 31, 2019, including approximately 7,800 employees in Canada and approximately 3,500 employees in the United States. Approximately 1,700 of our employees are subject to collective bargaining agreements governing their employment with us. All of the collective bargaining agreements governing our employees have expired or will expire during the year ended December 31, 2020. We are currently in the process of collective bargaining with respect to the expired or expiring contracts. We have mature working relationships with our labor unions and the parties have traditionally committed themselves to the achievement of renewal agreements without a work stoppage.

## EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers:

| Name | Age | Position |
|---|---|---|
| Al Monaco | 60 | President & Chief Executive Officer |
| Colin K. Gruending | 50 | Executive Vice President & Chief Financial Officer |
| Robert R. Rooney | 63 | Executive Vice President & Chief Legal Officer |
| John K. Whelen | 60 | Executive Vice President & Chief Development Officer |
| William T. Yardley | 55 | Executive Vice President & President, Gas Transmission and Midstream |
| Cynthia L. Hansen | 55 | Executive Vice President & President, Gas Distribution and Storage |
| Byron C. Neiles | 54 | Executive Vice President, Corporate Services |
| D. Guy Jarvis | 56 | Executive Vice President, Liquids Pipelines |
| Vern D. Yu | 53 | Executive Vice President & President, Liquids Pipelines |
| Laura B. Sayavedra | 52 | Senior Vice President, Projects, Safety and Reliability, and ERP |

Al Monaco was appointed President and Chief Executive Officer on October 1, 2012. Mr. Monaco is also a member of the Enbridge Board of Directors. Prior to being appointed President of Enbridge, Mr. Monaco served as President, Gas Pipelines, Green Energy and International with responsibility for the growth and operations of our gas pipelines, including the gas gathering and processing operations in the United States, our gulf coast offshore assets and our investments in Alliance Pipeline, Vector and Aux Sable, as well as our International business development and investment activities and Renewable Power Generation.

Colin K. Gruending was appointed Executive Vice President and Chief Financial Officer of Enbridge on June 1, 2019. Previously, our Senior Vice President, Corporate Development and Investment Review, Mr. Gruending performed a number of progressively challenging executive roles such as Vice President Corporate Development and Planning and Vice President, Treasury and Tax while concurrently serving as Chief Financial Officer for Enbridge Income Fund and Enbridge Income Fund Holdings Inc. Prior to that, Mr. Gruending served as Corporate Controller and also led enterprise Investor Relations and Pension Investments.

Robert R. Rooney was appointed Executive Vice President and Chief Legal Officer on February 1, 2017. Mr. Rooney leads our legal and aviation teams across the organization.

John K. Whelen was appointed Executive Vice President and Chief Development Officer on June 1, 2019. Previously, our Executive Vice President and Chief Financial Officer, Mr. Whelen held responsibility for our financial reporting function, as well as our tax, treasury and risk management functions. Prior to that, Mr. Whelen served as Senior Vice President and Controller, Senior Vice President Corporate Development and Vice President and Treasurer. Mr. Whelen has been part of the Enbridge team since 1992.

William T. Yardley was named Executive Vice President and President, Gas Transmission and Midstream on February 27, 2017 coincident with the closing of the Merger Transaction. Mr. Yardley, based in Houston, was previously President of Spectra Energy's United States Transmission and Storage business, leading the business development, project execution, operations and environment, health and safety efforts associated with Spectra Energy's United States portfolio of assets.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Distribution and Storage, on June 1, 2019. Ms. Hansen is responsible for the overall leadership and operations of Enbridge Gas, following the amalgamation of EGD and Union Gas, as well as Gazifère. Previously, our Executive Vice President, Utilities and Power Operations, Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders.

Byron C. Neiles was appointed Executive Vice President, Corporate Services on May 2, 2016. Mr. Neiles has oversight of our Technology & Information Services, Human Resources, Real Estate, Supply Chain Management, and Public Affairs, Communications & Sustainability. Mr. Neiles had previously held the role of Senior Vice President, Major Projects, Enterprise Safety and Operational Reliability and had been Senior Vice President of Major Projects since November 2011, after joining our Major Projects group in April 2008.

D. Guy Jarvis was appointed Executive Vice President, Liquids Pipelines on June 1, 2019. Mr. Jarvis had previously been President of our Liquids Pipelines group, with responsibility for all of our crude oil and liquids pipeline businesses across North America. Mr. Jarvis previously held the title of Chief Commercial Officer for Liquids Pipelines, with responsibility for strategic and integrated services, customer service, finance, and business and market development. Prior to Mr. Jarvis' work in Liquids Pipelines, he served as President, Gas Distribution, providing overall leadership to EGD, as well as EGNB and Gazifère. On November 7, 2019, Mr. Jarvis notified us of his intention to retire effective February 28, 2020.

Vern D. Yu was appointed Executive Vice President and President, Liquids Pipelines on January 1, 2020. Previously, Mr. Yu served as President and Chief Operating Officer for Liquids Pipelines and prior to that served as Executive Vice President and Chief Development Officer. He had previously served as Senior Vice President, Corporate Planning and Chief Development Officer. Prior to joining Corporate Development, Mr. Yu served as Senior Vice President of Business and Market Development for Enbridge's Liquids Pipelines division and previously has held a series of roles with increasing responsibility in our corporate and financial areas.

Laura B. Sayavedra was appointed Senior Vice President, Projects, Safety and Reliability and Enterprise Resource Planning (ERP) on June 1, 2019. Ms. Sayavedra is accountable for providing the overall strategic vision, leadership, integration and executive oversight of Enbridge's enterprise-wide Projects, Safety and Reliability, and ERP functions spanning operations in Canada and the United States, including multiple interests, jurisdictions and sensitivities. Previously, Ms. Sayavedra served as Vice President of Finance Transformation and took on a leadership role for the multi-year ERP program in late 2017.

# ADDITIONAL INFORMATION

Additional information about us is available on our website at www.enbridge.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K. We make available free of charge, through our website, annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC's website (www.sec.gov).

**ENBRIDGE GAS INC.**
Additional information about Enbridge Gas can be found in its annual information form, financial statements and management's discussion and analysis (MD&A) for the year ended December 31, 2019, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Enbridge Gas and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

**ENBRIDGE PIPELINES INC.**
Additional information about Enbridge Pipelines Inc. (EPI) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2019, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EPI and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

**WESTCOAST ENERGY INC.**
Additional information about Westcoast Energy Inc. can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2019, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Westcoast Energy Inc. and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

**DCP MIDSTREAM LP**
Additional information about DCP Midstream can be found in its Annual Report on Form 10-K that will be filed with the SEC. This document contains detailed disclosure with respect to DCP Midstream, and will be publicly available on EDGAR at www.sec.gov. No part of the Form 10-K filed by DCP Midstream is, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

# ITEM 1A. RISK FACTORS

***Pipeline operations involve numerous risks that may adversely affect our business and financial results.***

Operation of complex pipeline systems, gathering, treating, storing and processing operations involves many risks, hazards and uncertainties. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events, including those related to climate change, such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. These types of catastrophic events could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, any of which could also result in substantial losses for which insurance may not be sufficient or available and for which we may bear a part or all of the cost. We have experienced such events in the past, including in 2010 on Lines 6A and 6B of the Lakehead System, in October 2018 at the British Columbia (BC) Pipeline T-South system, in January 2019 at the Texas Eastern pipeline, and in August 2019 at the Texas Eastern pipeline, and cannot guarantee that we will not experience catastrophic events in the future. In addition, we could be subject to litigation and significant fines and penalties from regulators in connection with any such events. Environmental incidents could also lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings. An environmental incident could have lasting reputational impacts to us and could impact our ability to work with various stakeholders. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these catastrophic events could be greater.

***A service interruption could have a significant impact on our operations, and negatively impact financial results, relationships with stakeholders and our reputation.***

A service interruption due to a major power disruption, curtailment of commodity supply, operational incident or other reasons could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders and our reputation. Service interruptions that impact our crude oil and natural gas transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements.

***Our operations involve safety risks to the public and to our workers and contractors.***

Several of our pipelines and distribution systems and related assets are operated in close proximity to populated areas and a major incident could result in injury or loss of life to members of the public. In addition, given the natural hazards inherent in our operations, our workers and contractors are subject to personal safety risks. A public safety incident or an injury or loss of life to our workers or contractors could result in reputational damage to us, material repair costs or increased costs of operating and insuring our assets.

***Cyber-attacks or security breaches could adversely affect our business, operations or financial results.***

Our business is dependent upon information systems and other digital technologies for controlling our plants and pipelines, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems, or the network or systems of our third-party vendors, could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store or distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we and our third-party vendors collect and store sensitive data in the ordinary course of our business, including personal identification information of our employees as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. We have a cyber-security controls framework in place which has been derived from the National Institute of Standards. We monitor our control effectiveness in an increasing threat landscape and continuously take action to improve our security posture. We have implemented a security operations center, which operates at all times to monitor, detect and investigate any anomalous activity in our network together with an incident response process that we test on a monthly basis. We conduct independent cyber-security audits and penetration tests on a regular basis to test that our preventative and detective controls are working as designed.

Despite our security measures, our information systems, or those of our vendors, may become the target of cyber-attacks (including hacking, viruses or acts of terrorism) or security breaches (including employee error, malfeasance or other breaches), which could compromise our network or systems, or those of our vendors, and result in the release or loss of the information stored therein, misappropriation of assets, disruption to our operations or damage to our facilities. As a result of a cyber-attack or security breach, we could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, experience damage to our reputation or a loss of consumer confidence in our products and services, or incur additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could adversely affect our reputation, business, operations or financial results.

***There are utilization risks in respect to our assets.***

In respect to our Liquids Pipeline assets, we are exposed to throughput risk under the CTS on the Canadian Mainline and under certain tolling agreements applicable to other Liquids Pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect our revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of our assets. Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions outside of our control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

In respect to our Gas Transmission and Midstream, gas supply and demand dynamics continue to change as a result of the development of non-conventional shale gas supplies. The increase in natural gas supply has resulted in declines in the price of natural gas in North America. As a result, a shift occurred to extraction of gas in richer, wet gas areas with higher NGL content which depressed activity in dry fields. This, in turn, has contributed to a resulting oversupply of pipeline takeaway capacity in some areas, which can adversely affect our revenues and earnings.

In respect to our Gas Distribution and Storage assets, customers are billed on a combination of both fixed charge and volumetric basis and our ability to collect their respective total revenue requirement (the cost of providing service, including a reasonable return to the utility) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volumes is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Weather is a significant driver of delivery volumes, given that a significant portion of our Gas Distribution customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption. Our Gas Distribution business has deferral accounts approved by the OEB that provide regulatory protection against the margin impacts associated with declining annual average consumption due to efficiencies and customers' conservation efforts. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Even in those circumstances where we attain our respective total forecast distribution volume, our Gas Distribution business may not earn its expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. Our Gas Distribution business remains at risk for the actual versus forecast large volume contract commercial and industrial volumes.

In respect to our Renewable Power Generation assets, earnings from these assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Renewable Power Generation projects are predicted using long-term historical data, wind and solar resources are subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the Renewable Power Generation facilities could lead to decreased earnings and cash flows for us. Additionally, inefficiencies or interruptions of Renewable Power Generation facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Power produced from Renewable Power Generation assets is also often sold to a single counterparty under power purchase agreements or other long-term pricing arrangements. In this respect, the performance of the Renewable Power Generation assets is dependent on each counterparty performing its contractual obligations under the power purchase agreements or pricing arrangement applicable to it.

***An impairment of our assets, including goodwill, property, plant, and equipment, intangible assets, and/or equity method investments, could reduce our earnings.***

U.S. GAAP requires us to test certain assets for impairment on either an annual basis or when events or circumstances occur which indicate that the carrying value of such assets might be impaired. The outcome of such testing could result in impairments of our assets including our goodwill, property, plant and equipment, intangible assets, and/or equity method investments. Additionally, any asset monetizations could result in impairments if such assets are sold or otherwise exchanged for amounts less than their carrying value. If we determine that an impairment has occurred, we would be required to take an immediate noncash charge to earnings.

***Our assets vary in age and were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future.***

Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction, some assets require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our business, operations or financial results.

***Competition may result in a reduction in demand for our services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected.***

We face competition from competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada, the United States and internationally and from proposed pipelines that seek to access markets currently served by our liquids pipelines. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. We also face competition from alternative gathering and storage facilities. Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Competition in all of our businesses, including competition for new project development opportunities, could have a negative impact on our business, financial condition or results of operations.

***Execution of our projects subjects us to various regulatory, development, operational and market risks that may affect our financial results.***

Our ability to successfully execute our projects is subject to various regulatory, development, operational, litigation and market risks, including:

- the ability to obtain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and to maintain those issued approvals and permits and satisfy the terms and conditions imposed therein;
- potential changes in federal, state, provincial and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms;
- opposition to our projects and operations by third parties, including interest groups;
- the availability of skilled labor, equipment and materials to complete projects;
- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, contractor or supplier non-performance, weather, geologic conditions or other factors beyond our control, that may be material;
- general economic factors that affect the demand for our projects; and
- the ability to raise financing for these projects.

Climate related risks are integrated into multiple of our larger risk categories that encompass operational, financial and stakeholder consequences. This is done because of the interconnected economic, social and environmental nature of climate impacts requires a comprehensive review within the context of other risks that impact us.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost. Recent projects that have experienced delays include the U.S. L3R Program, Atlantic Bridge, Spruce Ridge Project and the T-South Reliability and Expansion Project. New projects may not achieve their expected investment return, which could affect our financial results, and hinder our ability to secure future projects. For additional discussion of specific proceedings that could affect our operations and financial results, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates.*

***Erosion of stakeholder trust or confidence or changes in our reputation with stakeholders, interest groups, political leadership, the media or other entities could influence actions or decisions about our company and industry and have negative impacts on our business, operations or financial results.***

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders including local communities, Indigenous communities, and other groups directly impacted by our activities, as well as governments and government agencies. Inadequately managing expectations and issues important to stakeholders, including those related to environment and climate change, could affect stakeholder trust and confidence and our reputation.

There could be negative impacts on our business, operations or financial results due to erosion of stakeholder trust or confidence or changes in our reputation with stakeholders, interest groups (including non-governmental organizations), political leadership, the media or other entities. Public and stakeholder opinion may be influenced by certain media and others' negative portrayal of the industry in which we operate as well as their opposition to our projects and ongoing operations. Potential impacts of an erosion of stakeholder trust or confidence or negative public opinion may include:

- loss of business;
- loss of ability to secure growth opportunities;
- delays in project execution;
- legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin;
- increased regulatory oversight;
- negative impact on our ability to obtain and maintain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms
- changing investor sentiment regarding investment in the oil and gas industry or our company;
- negative impact on access to and cost of capital; and
- loss of ability to hire and retain top talent.

We are also exposed to the risk of higher costs, delays, project cancellations, new restrictions or the cessation of operations of existing pipelines due to increasing pressure on governments and regulators. Recent judicial decisions have increased the ability of groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, we and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil and gas extraction and shipment of oil and gas products.

***Our forecasted assumptions may not materialize as expected on our expansion projects, acquisitions and divestitures.***

We evaluate expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, change in cost estimates, project scoping and risk assessment could result in a loss in our profits.

***Many of our operations are regulated and failure to secure regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, financial condition or results of operations.***

The nature and degree of regulation and legislation affecting energy companies in Canada and the United States have changed significantly in past years.

In Canada, the passing of the CER Act and the Impact Assessment Act under Bill C-69, which came into force on August 28, 2019, is expected to extend timelines associated with regulatory approvals for new projects which fall under Canadian federal jurisdiction and meet the criteria for an environmental impact assessment. Changes to the British Columbia regulatory framework have also been made, affecting provincially-regulated projects in a similar manner as those that are federally-regulated. Within the United States, pipelines companies continue to face opposition from anti-oil activists, Indigenous communities, citizens, environmental groups and politicians concerned with either the safety of pipelines or keeping oil in the ground. In the United States, several federal agencies are proposing changes to regulations pursuant to Executive Orders requiring them to streamline permitting, which would include changes to Section 401 of the Clean Water Act and the National Environmental Policy Act. These regulations are anticipated to be finalized this year but will be challenged in court and could be modified or withdrawn with a new administration. Additionally there are numerous cases pending in federal court challenging various aspects of other laws or regulations that could adversely impact permitting.

We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs.

***Our operations are subject to numerous environmental laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans, or expose us to environmental liabilities.***

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste.

Failure to comply with environmental laws and regulations and failure to secure permits necessary for our operations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations, including those related to climate change and GHG emissions, could result in a material increase in our cost of compliance with such laws and regulations.

We may not be able to obtain or maintain all required environmental regulatory approvals and permits for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain or comply with them, or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. We expect that costs we incur to comply with environmental regulations in the future may have a significant effect on our earnings and cash flows.

***Our operations are subject to operational regulation and other requirements, including compliance with easements and other land tenure documents, and failure to comply with applicable regulations and other requirements could have a negative impact on our business, financial condition or results of operations.***

Operational risks relate to compliance with applicable operational rules and regulations mandated by governments, applicable regulatory authorities, or other requirements that may be found in easements or other agreements that provide a legal basis for our operations, breaches of which could result in fines, penalties, awards of damages, operating restrictions (including shutdown of lines) and an overall increase in operating and compliance costs. Scrutiny over the integrity of our assets and operations has the potential to increase operating costs or limit future projects. Potential regulatory changes and legal challenges could have an impact on our future earnings from existing operations and the cost related to the construction of new projects. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. While we seek to mitigate operational regulation risk by active monitoring and consulting on potential regulatory requirement changes with the respective regulators directly, or through industry associations, and by developing response plans to regulatory changes or enforcement actions, such mitigation efforts may be ineffective or insufficient. While we believe the safe and reliable operation of our assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators or other government officials to make unilateral decisions that could have a financial impact on us.

***Our operations are subject to economic regulation and failure to secure regulatory approval for our proposed or existing commercial arrangements could have a negative impact on our business, financial condition or results of operations.***

Our liquids pipelines face economic regulatory risk, the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements. We believe that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of our liquids pipeline assets. However, there remains a risk that a regulator could modify significantly its own long-standing policies for rate making as well as overturn long-term agreements that we have entered into with shippers.

***Our transformation projects may fail to fully deliver anticipated results.***

We launched projects starting in 2016 to transform various processes, capabilities and reporting systems infrastructure to continuously improve effectiveness and efficiency across the organization and are subject to transformation project risk with respect to these projects. Such projects, some of which will continue into 2020 and 2021, including integration initiatives arising out of the merger with Spectra Energy and the amalgamation of EGD and Union Gas, are subject to transformation project risk. Transformation project risk is the risk that modernization projects carried out by us and our subsidiaries do not fully deliver anticipated results due to insufficiently addressing the risks associated with project execution and change management. This could result in negative financial, operational and reputational impacts.

***We are exposed to the credit risk of our customers.***

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. A significant amount of our credit exposures for transmission and storage services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas and oil producers may be the primary customer, our credit exposure with below investment-grade customers may increase. It is possible that customer payment defaults, if significant, could adversely affect our earnings and cash flows.

***We could be subject to changes in our tax rates, the adoption of new United States, Canadian or international tax legislation or exposure to additional tax liabilities.***

We are subject to taxes in the United States, Canada and numerous foreign jurisdictions. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation, including in the United States, Canada and other foreign jurisdictions in which we operate.

We are also subject to the examination of our tax returns and other tax matters by the United States Internal Revenue Service, the Canada Revenue Agency and other tax authorities and governmental bodies. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in the United States or Canada, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

***Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.***

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. If we are unable to retain current employees and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

***We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results.***

We are subject to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for a discussion of legal proceedings.

***Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war, and other civil unrest or activism could adversely affect our business, operations or financial results.***

Terrorist attacks and threats, escalation of military activity or acts of war, or other civil unrest or activism may have significant effects on general economic conditions and may cause fluctuations in consumer confidence and spending and market liquidity, each of which could adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States, or Canada, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy related assets, may be at greater risk of future attacks than other targets in the United States and Canada. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, increased legislation or denial or delay of permits and rights-of-way. Finally, the disruption or a significant increase in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could adversely affect our business, operations or financial results.

***Our Liquids Pipelines growth rate and results may be directly and indirectly affected by commodity prices and Government policy.***

The efforts implemented in 2019 by the Alberta Government to manage supply and inventories in Western Canada is expected to continue at diminishing levels to the end of 2020 as incremental take away capacity is introduced to the market. This intervention has negligible impact on mainline throughput, as enough inventory exists to meet refinery customer needs and service our favorable markets. Wide commodity price basis between Western Canada and global tidewater markets have negatively impacted producer netbacks and margins in the past years that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects.

The tight oil plays of Western Canada and the Bakken region of North Dakota have short cycle break-even time horizons, typically less than 24 months, and high decline rates that can be well managed through active hedging programs and are positioned to react quickly at market signals. Accordingly, during periods of comparatively low prices, drilling programs, unsupported by hedging programs, will be reduced and as such supply growth from tight oil basins may be lower, which may impact volumes on our pipeline systems.

***Our Gas Transmission and Midstream results may be adversely affected by commodity price volatility and risks associated with our hedging activities.***

Our exposure to commodity price volatility is inherent to part of our natural gas processing business. We employ a disciplined hedging program to manage this direct commodity price risk. Because we are not fully hedged, we may be adversely impacted by commodity price exposure on the commodities we receive in-kind as payment for our gathering, processing, treating and transportation services. As a result of our unhedged exposure and the pricing of our hedge positions, a substantial decline in the prices of these commodities could adversely affect our financial results.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. To the extent that we engage in hedging activities to reduce our commodity price exposure, we likely will be prevented from realizing the full benefits of price increases above the level of the hedges. Our hedging activities can result in substantial losses if hedging arrangements are imperfect or ineffective and our hedging policies and procedures are not followed properly or do not work as intended. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. In addition, certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to fluctuations in commodity prices.

***Our Energy Services results may be adversely affected by commodity price volatility.***

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Volatility in commodity prices due to changing market conditions could limit margin opportunities and impede Energy Services' ability to cover capacity commitments. Furthermore, commodity prices could have negative earnings and cash flow impacts if the cost of the commodity is greater than resale prices achieved by us.

***Our risk management policies cannot eliminate all risks. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.***

We use derivative financial instruments to manage the risks associated with movements in foreign exchange rates, interest rates, commodity prices and our share price to reduce volatility of our cash flows. Based on our risk management policies, all of our derivative financial instruments are associated with an underlying asset, liability and/or forecasted transaction. We do not enter into transactions with the objective of speculating on commodity prices or interest rates. These policies cannot, however, eliminate all risk of unauthorized trading and other speculative activity. Although this activity is monitored independently by our risk management function, we remain exposed to the risk of non-compliance with our risk management policies. We can provide no assurance that our risk management function will detect and prevent all unauthorized trading and other violations of our risk management policies and procedures, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

***We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and cost effective access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating.***

A significant portion of our consolidated asset base is financed with debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. Consequently, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings and/or letters of credit at various entities. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility, which could affect cash flows or restrict business. Furthermore, if our short-term debt rating were to be downgraded, access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

***Our insurance coverage may not be sufficient to cover our losses in the event of an accident, natural disaster or other hazardous event.***

Our operations are subject to many hazards inherent in our industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We maintain a comprehensive insurance program for us, our subsidiaries and certain of our affiliates to mitigate the financial impacts arising from these hazards. This program includes insurance coverage in types and amounts and with terms and conditions that are generally consistent with coverage customary for our industry, however insurance does not cover all events in all circumstances.

In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among our entities on an equitable basis based on an insurance allocation agreement among us and our subsidiaries. Additionally, even with insurance, if any natural disaster or other hazardous event leads to a catastrophic interruption in operations, we may not be able to restore operations without significant interruption.

***The effects of United States Government policies on trade relations between Canada and the United States are uncertain.***

The new United States-Mexico-Canada Agreement (USMCA) (in Canada, known as the Canada-United States-Mexico Agreement (CUSMA) is intended to supersede the North American Free Trade Agreement (NAFTA). The USMCA/CUSMA has been ratified by the United States and Mexico, and will not come into effect until after Canada ratifies the agreement. NAFTA provides protection against tariffs, duties and other charges or fees and assures access by the signatories. The impact of USMCA/CUSMA, if ratified, on energy markets is uncertain.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

Descriptions of our properties and maps depicting the locations of our liquids and natural gas systems are included in *Item 1. Business.*

In general, our systems are located on land owned by others and are operated under easements and rights-of-way, licenses, leases or permits that have been granted by private land owners, First Nations, Native American Tribes, public authorities, railways or public utilities. Our liquids systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us and/or used by us under easements, licenses, leases or permits. Additionally, our natural gas systems have natural gas compressor stations, processing plants and treating plants, the vast majority of which are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to our properties acquired in our liquids and natural gas systems are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

## ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and administrative proceedings and litigation arising in the ordinary course of business. The outcome of these matters is not predictable at this time. However, we believe that the ultimate resolution of these matters will not have a material adverse effect on our financial condition, results of operations or cash flows in future periods. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of other legal proceedings.

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

# PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Common Stock**
Our common stock is traded on the TSX and NYSE under the symbol “ENB.” As at February 7, 2020, there were approximately 2,024,814,011 holders of record of our common stock. A substantially greater number of holders of our common stock are "street name" or beneficial holders, whose shares are held by banks, brokers and other financial institutions.

**Dividends**
The following table indicates the dividends paid per common share (in Canadian dollars):

| | **2019** | 2018 |
|---|---|---|
| Q1 | **0.738** | 0.671 |
| Q2 | **0.738** | 0.671 |
| Q3 | **0.738** | 0.671 |
| Q4 | **0.738** | 0.671 |

Consistent with our objective of delivering annual cash dividend increases, we announced a quarterly dividend of $0.81 per common share payable on March 1, 2020, which represents a 9.8 percent increase from the prior quarterly rate. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors.

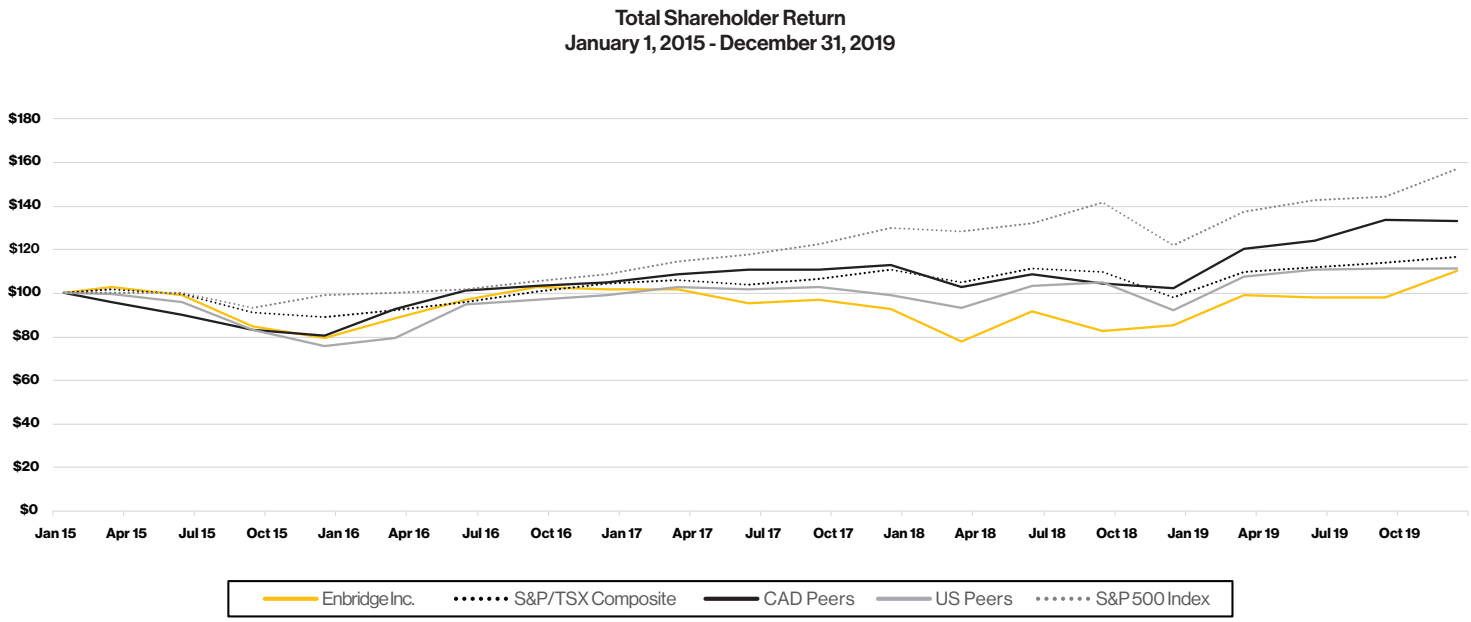
**Securities Authorized for Issuance Under Equity Compensation Plans**
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019.

**Recent Sales of Unregistered Equity Securities**
None.

**Issuer Purchases of Equity Securities**
None.

**Total Shareholder Return**

The following graph reflects the comparative changes in the value from January 1, 2015 through December 31, 2019 of $100 invested in (1) Enbridge Inc.'s common shares traded on the TSX, (2) the S&P/TSX Composite index, (3) the S&P 500 index, (4) our United States peer group (comprising D, DTE, ET, EPD, KMI, MMP, NI, OKE, PCG, PAA, SRE and WMB) and (5) our Canadian peer group (comprising CU, FTS, IPL, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.




| | January 1, 2015 | December 31, | | | | |
|---|---|---|---|---|---|---|
| | | 2015 | 2016 | 2017 | 2018 | 2019 |
| Enbridge Inc. | 100.00 | 79.66 | 101.94 | 92.93 | 85.40 | 110.45 |
| S&P/TSX Composite | 100.00 | 88.91 | 104.48 | 110.78 | 97.88 | 116.61 |
| S&P 500 Index | 100.00 | 99.27 | 108.74 | 129.86 | 121.76 | 156.92 |
| United States Peers[1] | 100.00 | 75.58 | 99.08 | 99.42 | 92.47 | 111.43 |
| Canadian Peers | 100.00 | 80.50 | 105.22 | 113.05 | 102.32 | 133.14 |

*1 For the purpose of the graph, it was assumed that CAD:USD conversion ratio remained at 1:1 for the years presented.*

# ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data is not necessarily indicative of results of future operations and should be read in conjunction with *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Item 8. Financial Statements and Supplementary Data* to fully understand factors that may affect the comparability of the information presented below.

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | 2016 | 2015 |
| *(millions of Canadian dollars, except per share amounts)* | | | | | |
| **Consolidated Statements of Earnings** | | | | | |
| Operating revenues | **$ 50,069** | $ 46,378 | $ 44,378 | $ 34,560 | $ 33,794 |
| Operating income | **8,260** | 4,816 | 1,571 | 2,581 | 1,862 |
| Earnings/(loss) from continuing operations | **5,827** | 3,333 | 3,266 | 2,309 | (159) |
| (Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests | **(122)** | (451) | (407) | (240) | 410 |
| Earnings attributable to controlling interests | **5,705** | 2,882 | 2,859 | 2,069 | 251 |
| Earnings/(loss) attributable to common shareholders | **5,322** | 2,515 | 2,529 | 1,776 | (37) |
| **Common Stock Data** | | | | | |
| Earnings/(loss) per common share | | | | | |
| Basic | **2.64** | 1.46 | 1.66 | 1.95 | (0.04) |
| Diluted | **2.63** | 1.46 | 1.65 | 1.93 | (0.04) |
| Dividends paid per common share | **2.95** | 2.68 | 2.41 | 2.12 | 1.86 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | 2016 | 2015 |
| *(millions of Canadian dollars)* | | | | | |
| **Consolidated Statements of Financial Position** | | | | | |
| Total assets[1] | **$ 163,269** | $ 166,905 | $ 162,093 | $ 85,209 | $ 84,154 |
| Long-term debt including capital leases, less current portion | **59,661** | 60,327 | 60,865 | 36,494 | 39,391 |

*1 We combined Cash and cash equivalents and other amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to pooling arrangements.*

# ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

## INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2019 and 2018 items and year-over-year comparisons between 2019 and 2018. For discussion of 2017 items and year-over-year comparisons between 2018 and 2017, refer to Part II. *Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2018.

## RECENT DEVELOPMENTS

### CANADIAN LINE 3 REPLACEMENT PROGRAM PLACED INTO SERVICE

The Canadian Line 3 Replacement Program was placed into service on December 1, 2019, with an interim surcharge on Mainline System volumes of US$0.20 per barrel. This safety-driven maintenance project reflects the importance of protecting the environment and ensuring the continued safe and reliable operations of our Mainline System well into the future. For further details refer to *Growth Projects - Commercially Secured Projects - Liquids Pipelines*.

### STATE OF MINNESOTA PERMITTING TIMELINE FOR U.S. LINE 3 REPLACEMENT PROGRAM

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the Minnesota Public Utilities Commission's (MNPUC's) adequacy determination of the Final Environmental Impact Statement (FEIS) for the U.S. L3R Program. While denying eight of the nine appealed items, the Minnesota Court of Appeals identified one issue that led it to reverse the adequacy determination. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents' petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019. The Department of Commerce issued the revised FEIS on December 9, 2019, and the MNPUC gathered public comment on that document through January 16, 2020. On February 3, 2020, the MNPUC approved the adequacy of the revised FEIS and reinstated the Certificate of Need and Route Permit, clearing the way for construction of the pipeline to commence following the issuance of required permits.

At this time, we cannot determine when all necessary permits to commence construction will be issued. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

**MAINLINE SYSTEM CONTRACTING**

On August 2, 2019, we launched an open season for transportation services on our Mainline System. The open season provided shippers with the opportunity to enter into long-term contracts for priority access on the Mainline System upon maturity of the current CTS agreement on June 30, 2021.

On September 27, 2019, after receiving complaints, the CER ordered that we may not offer firm service to prospective shippers on our Mainline System until such firm service, including all associated tolls and terms and conditions of service, has been approved by the CER. While this decision was a significant departure from past regulatory precedents, the CER noted that its decision to hold a regulatory review prior to the open season does not prejudice our ability to offer long term priority access contracts on the Mainline System.

On December 19, 2019, we submitted an application to the CER to implement contracting on our Mainline System. The application for contracted and uncommitted service included the associated terms, conditions and tolls of each service, which would be offered in an open season following approval by the CER. The tolls and services would replace the current CTS that is in place until June 30, 2021. If a replacement agreement is not in place by that time, the CTS tolls will continue on an interim basis.

The application that we filed is the result of over two years of extensive negotiations with a diverse group of shippers and has been designed to align the interests of us and our shippers. Shippers, which represent over 70 percent of our current Mainline System throughput, have filed letters supporting the application with the CER, demonstrating the strong shipper backing for the offering.

On February 7, 2020, we replied to the letters solicited by the CER regarding comments from interested parties both in opposition and support of our application. We expect a thorough regulatory process to continue through substantially all of 2020.

**ASSET MONETIZATION**

**Enbridge Gas New Brunswick Business**
On October 1, 2019, we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power & Utilities Corp., for proceeds of approximately $331 million.

**St. Lawrence Gas Company Inc.**
On November 1, 2019, we closed the sale of the issued and outstanding shares of St. Lawrence Gas for proceeds of approximately $72 million.

**Canadian Natural Gas Gathering and Processing Businesses**
On December 31, 2019, we closed the sale of the federally regulated Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners (collectively, Brookfield) for proceeds of approximately $1.7 billion, after closing adjustments. These federally regulated businesses represent the second and final phase of the $4.3 billion transaction that was previously announced on July 4, 2018.

**Montana-Alberta Tie Line**
In the fourth quarter of 2019, we committed to a plan to sell the MATL transmission assets. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

Refer to *Liquidity and Capital Resources - Sources and Uses of Cash* for details on the use of proceeds from our asset monetization activity discussed above.

**ENBRIDGE GAS INC. 2019 RATE APPLICATION**

In September 2019, Enbridge Gas received a Decision and Order from the OEB on its application for 2019 rates. The 2019 rate application was filed in December 2018 in accordance with the parameters of Enbridge Gas's OEB approved Price Cap Incentive Regulation rate setting mechanism and represents the first year of a five-year term. The Decision and Order approved an effective date for base rates of April 1, 2019, and the inclusion of incremental capital module amounts to allow for the recovery of incremental capital investments.

**ENBRIDGE GAS INC. 2020 RATE APPLICATION**

In October 2019, Enbridge Gas filed an application with the OEB for the setting of rates for 2020 and for the funding of discrete incremental capital investments through the incremental capital module mechanism. The 2020 rate application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap Incentive Regulation rate setting mechanism and represents the second year of a five-year term. In December 2019, Enbridge Gas received a Decision and Order from the OEB which approved 2020 rates on an interim basis effective January 1, 2020. A decision on Enbridge Gas' application for incremental capital module amounts is expected in the second quarter of 2020.

**TEXAS EASTERN PIPELINE RUPTURE**

On August 1, 2019, a rupture occurred on Line 15, a 30-inch natural gas pipeline that is a component of the Texas Eastern natural gas pipeline system in Lincoln County, Kentucky. While the two adjacent pipelines have been returned to service, Line 15 remains shut down in the affected area and the timeline for its return to service has not yet been determined. There was one fatality. We are continuing to support the National Transportation Safety Board in its investigation, the community and the community members who were impacted by the rupture. The Texas Eastern natural gas pipeline system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York.

Due to the incident, before expected recoveries, we experienced lower revenues and higher operating costs of $34 million in 2019. Texas Eastern Transmission, LP (Texas Eastern) is included in a comprehensive insurance program that is maintained for our subsidiaries and affiliates, which includes liability, property and business interruption insurance.

**TEXAS EASTERN RATE CASE**

On June 1, 2019, Texas Eastern put into effect its updated rates. These increased recourse rates are subject to refund and interest. Following extensive negotiations on the Texas Eastern rate case, we reached an agreement with shippers and filed a Stipulation and Agreement with the FERC on October 28, 2019. On January 13, 2020, the Administrative Law Judge certified this uncontested Stipulation and Agreement to the FERC and we expect a decision from the FERC in the second quarter of 2020. Upon receipt of a decision from the FERC we will begin recognizing updated rates within our results of operations.

# RESULTS OF OPERATIONS

| | Year ended December 31 | | |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| *(millions of Canadian dollars, except per share amounts)* | | | |
| **Segment earnings/(loss) before interest, income taxes and depreciation and amortization** | | | |
| Liquids Pipelines | **7,681** | 5,331 | 6,395 |
| Gas Transmission and Midstream | **3,371** | 2,334 | (1,269) |
| Gas Distribution and Storage | **1,747** | 1,711 | 1,390 |
| Renewable Power Generation | **111** | 369 | 372 |
| Energy Services | **250** | 482 | (263) |
| Eliminations and Other | **429** | (708) | (337) |
| Depreciation and amortization | **(3,391)** | (3,246) | (3,163) |
| Interest expense | **(2,663)** | (2,703) | (2,556) |
| Income tax expense | **(1,708)** | (237) | 2,697 |
| Earnings attributable to noncontrolling interests and redeemable noncontrolling interests | **(122)** | (451) | (407) |
| Preference share dividends | **(383)** | (367) | (330) |
| Earnings attributable to common shareholders | **5,322** | 2,515 | 2,529 |
| Earnings per common share | **2.64** | 1.46 | 1.66 |
| Diluted earnings per common share | **2.63** | 1.46 | 1.65 |

## EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

**Year ended December 31, 2019 compared with year ended December 31, 2018**

Earnings Attributable to Common Shareholders were net positively impacted by $2,034 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized derivative fair value gain of $1,806 million ($1,276 million after-tax attributable to us) in 2019, compared with a loss of $660 million ($397 million after-tax attributable to us) in 2018, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks;
- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of $188 million ($144 million after-tax attributable to us) in 2019, compared with $327 million ($239 million after-tax attributable to us) in 2018;
- the absence in 2019 of a goodwill impairment charge of $1,019 million after-tax attributable to us in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- the absence in 2019 of a loss of $913 million ($701 million after-tax attributable to us) in 2018 on Midcoast Operating, L.P. and its subsidiaries (MOLP) resulting from a revision to the fair value of the assets held for sale based on the sale price*;*
- the absence in 2019 of a loss of $154 million ($95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell; and
- employee severance, transition and transformation costs of $140 million ($127 million after-tax attributable to us) in 2019, compared with $203 million ($181 million after-tax attributable to us) in 2018.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of $467 million after-tax attributable to us in 2019 ($268 million loss on sale and $199 million tax expense) resulting from the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses;
- a loss of $310 million ($229 million after-tax attributable to us) in 2019 resulting from the review of our comprehensive long-term economic hedging program and a payment to certain hedge counterparties to pre-settle and reset the hedge rate on a portion of our hedging program;
- a loss of $297 million ($218 million after-tax attributable to us) in 2019 resulting from the classification of our MATL assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell;
- a loss of $105 million ($79 million after-tax attributable to us) in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- a loss of $86 million ($68 million after-tax attributable to us) in 2019 related to sale of assets, asset write-down and goodwill impairment losses at our equity investee, DCP Midstream;
- the absence in 2019 of a recovery of $223 million after-tax in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission business rate base; and
- the absence in 2019 of a deferred income tax recovery of $267 million ($196 million attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on financial derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $773 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- increased earnings from our Liquids Pipelines segment due to higher Flanagan South, Seaway Pipeline and Bakken Pipeline System throughput year-over-year;
- stronger contributions from our Liquids Pipelines segment due to a higher IJT Benchmark Toll and higher Mainline System ex-Gretna throughput driven by an increase in supply and continuous capacity optimization;
- contributions from new Gas Transmission and Midstream assets placed into service in the fourth quarter of 2018 and 2019;
- increased earnings from our Gas Distribution and Storage segment due to colder weather experienced in our franchise areas, higher distribution rates and customer base, and the absence in 2019 of earnings sharing which was recognized in 2018;
- increased earnings from our Energy Services segment due to the widening of certain location and quality differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019;
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the Sponsored Vehicles buy-in in the fourth quarter of 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Canadian to United States dollar average exchange rate (Average Exchange Rate) of $1.33 in 2019 compared with $1.30 in 2018, partially offset by realized losses arising from our foreign exchange risk management program.

The positive business factors above were partially offset by the following:

- the absence in 2019 of earnings from MOLP and the provincially regulated portion of our Canadian natural gas gathering and processing businesses which were sold in the second half of 2018;
- higher operating costs on our Gas Transmission and Midstream assets primarily due to higher pipeline integrity costs;
- higher depreciation and amortization expense as a result of placing new assets into service, partially offset by depreciation no longer recorded for assets which were classified as held for sale or sold during the second half of 2018; and
- higher income tax expense due to higher earnings, the buy-in of our United States sponsored vehicles in the fourth quarter of 2018 and lower foreign tax rate differentials in 2019.

**REVENUES**

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of $16,555 million, $14,358 million and $13,877 million for the years ended December 31, 2019, 2018 and 2017, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of our cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on our core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past three years.

Gas distribution sales revenues of $4,205 million, $4,360 million and $4,215 million for the years ended December 31, 2019, 2018 and 2017, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales of $29,309 million, $27,660 million and $26,286 million for the years ended December 31, 2019, 2018 and 2017, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

**DIVIDENDS**

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2019, we announced a 9.8 percent increase in our quarterly dividend to $0.81 per common share, or $3.24 annualized, effective with the dividend payable on March 1, 2020.

# BUSINESS SEGMENTS

# LIQUIDS PIPELINES

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before interest, income taxes and depreciation and amortization | **7,681** | 5,331 | 6,395 |

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was positively impacted by $1,926 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of $976 million in 2019 compared with a loss of $1,077 million in 2018 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in 2019 of a loss of $154 million in 2018 related to Line 10, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of $310 million in 2019 resulting from the review of our comprehensive long-term economic hedging program and a payment to certain hedge counterparties to pre-settle and reset the hedge rate on a portion of our hedging program; and
- a loss of $21 million in 2019 related to the write-off of project development costs resulting from the withdrawal of our permit application for the Texas COLT Offshore Loading Project.

After taking into consideration the factors above, the remaining $424 million increase is primarily explained by the following significant business factors:

- higher Flanagan South and Seaway Pipeline throughput year-over-year driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest in the first half of 2019 and strong Gulf Coast demand resulting from favorable price differentials;
- higher Bakken Pipeline System throughput year-over-year driven by strong production in the region;
- higher Mainline System ex-Gretna throughput of 2,705 kbpd in 2019 compared with 2,631 kbpd in 2018 driven by an increase in supply and continuous capacity optimization;
- a higher average IJT Benchmark Toll of $4.18 in 2019 compared with $4.11 in 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.30 in 2018.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of US$1.19 in 2019 compared with US$1.26 in 2018.

## GAS TRANSMISSION AND MIDSTREAM

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings/(loss) before interest, income taxes and depreciation and amortization | **3,371** | 2,334 | (1,269) |

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately $240 million from the sale of MOLP on August 1, 2018 and the sale of the provincially regulated portion of our Canadian natural gas gathering and processing businesses on October 1, 2018.

EBITDA was positively impacted by $1,237 million due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- the absence in 2019 of a goodwill impairment charge of $1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale; and
- the absence in 2019 of a loss of $913 million in 2018 resulting from the further revision to the fair value of our MOLP assets held for sale based on the sale price.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of $268 million in 2019 resulting from the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses;
- a loss of $105 million in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- a loss of $86 million in 2019 related to the sale of assets, asset write-downs and goodwill impairment losses at our equity investee, DCP Midstream; and
- the absence in 2019 of a recovery of $223 million in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission business rate base.

After taking into consideration the factors above, the remaining $40 million increase is primarily explained by the following significant business factors:

- contributions from Valley Crossing Pipeline and certain other Offshore and US Gas Transmission assets that were placed into service during the fourth quarter of 2018 and 2019; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.30 in 2018.

The positive business factors above were partially offset by the following:

- higher operating costs on our US Gas Transmission assets primarily due to higher pipeline integrity costs;
- lower revenues and higher operating costs from US Gas Transmission due to the Texas Eastern natural gas pipeline system incident in Lincoln County, Kentucky, refer to *Recent Developments - Texas Eastern Rupture*; and
- decreased fractionation margins at our Aux Sable joint venture driven by lower NGL prices.

# GAS DISTRIBUTION AND STORAGE

| | 2019 | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before interest, income taxes and depreciation and amortization | **1,747** | 1,711 | 1,390 |

EGD and Union Gas were amalgamated on January 1, 2019. The amalgamated company has continued as Enbridge Gas. Post amalgamation the financial results of Enbridge Gas reflect the combined performance of EGD and Union Gas.

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was negatively impacted by $57 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- employee severance costs of $39 million in 2019 related to the amalgamation of EGD and Union Gas;
- a loss of $10 million in 2019 resulting from the sale of St. Lawrence Gas; and
- a non-cash, unrealized loss of $12 million in 2019 compared with a gain of $6 million in 2018 arising from the change in the mark-to-market value of our equity investee's, Noverco's derivative financial instruments.

The negative factors above were partially offset by the absence in 2019 of a negative equity earnings adjustment of $9 million in 2018 at our equity investee, Noverco, arising from the Tax Cuts and Jobs Act in the United States.

After taking into consideration the factors above, the remaining $93 million increase is primarily explained by the following significant business factors:

- increased earnings of $36 million resulting from colder weather experienced in our franchise service areas when compared with the corresponding period in 2018;
- increased earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base;
- the absence in 2019 of earnings sharing which was recognized in 2018 under EGD's previous incentive rate structure; and
- synergy captures realized from the amalgamation of EGD and Union Gas.

The positive business factors above were partially offset by the following:

- the effects of the accelerated capital cost allowance deductions reflected as a pass through to customers, consistent with the OEB's prescribed deferral account treatment; and
- the absence of contributions in 2019 from EGNB and St. Lawrence Gas which were sold on October 1, 2019 and November 1, 2019, respectively.

## RENEWABLE POWER GENERATION

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before interest, income taxes and depreciation and amortization | **111** | 369 | 372 |

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was negatively impacted by $247 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a loss of $297 million in 2019 resulting from the classification of our MATL assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell*;* and
- a loss of $10 million in 2019 related to the write-down of offshore transmission assets anticipated to be disposed of in 2020 at our equity investee, Rampion Offshore Wind Limited.

The negative factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- the absence in 2019 of a loss of $20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facility and its expansion;
- the absence in 2019 of an asset impairment charge of $22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- the absence in 2019 of a loss of $25 million in 2018 representing our share of losses incurred by our equity investee, Rampion Offshore Wind Limited, primarily due to the repair and restoration of damaged power transmission cables.

After taking into consideration the factors above, the remaining $11 million decrease is primarily explained by the following significant business factors:

- weaker wind resources at United States wind facilities;
- higher mechanical repair costs at certain United States wind facilities, net of insurance recoveries; and
- the absence in 2019 of $11 million in 2018 from a positive arbitration settlement related to our Canadian wind facilities.

The negative business factors above were partially offset by the following:

- contributions from the Hohe See Offshore Wind Project, which generated first power in July 2019 and reached full operating capacity in October 2019; and
- stronger wind resources at Canadian wind facilities.

## ENERGY SERVICES

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings/(loss) before interest, income taxes and depreciation and amortization | **250** | 482 | (263) |

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was net negatively impacted by $334 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of $169 million in 2019 compared with a gain of $642 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices. This negative factor was partially offset by a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of $188 million in 2019 compared with $327 million in 2018.

After taking into consideration the factors above, the remaining $102 million increase is primarily due to increased earnings from Energy Services crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

## ELIMINATIONS AND OTHER

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings/(loss) before interest, income taxes and depreciation and amortization | **429** | (708) | (337) |

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements which are not allocated to business segments. Eliminations and Other also includes the impact of new business development activities and corporate investments.

**Year ended December 31, 2019 compared with year ended December 31, 2018**

EBITDA was positively impacted by $1,123 million due to certain unusual, infrequent or other-non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of $671 million in 2019 compared with a loss of $256 million in 2018 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- employee severance, transition and transformation costs of $84 million in 2019 compared with $152 million in 2018; and
- the absence in 2019 of asset monetization transaction costs of $68 million in 2018.

After taking into consideration the factors above, the remaining $14 million increase is primarily explained by lower operating and administrative costs in 2019.

## GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our commercially secured projects, organized by business segment:

| | | Enbridge's Ownership Interest | Estimated Capital Cost[1] | Expenditures to Date[2] | Status | Expected In-Service Date |
|---|---|---|---|---|---|---|
| *(Canadian dollars, unless stated otherwise)* | | | | | | |
| **LIQUIDS PIPELINES** | | | | | | |
| 1. | AOC Lateral Acquisition | 100% | $0.3 billion | $0.3 billion | Complete | In-service |
| 2. | Gray Oak Pipeline Project | 22.8% | US$0.7 billion | US$0.4 billion | Complete | In-service |
| 3. | Canadian Line 3 Replacement Program | 100% | $5.3 billion | $4.9 billion | Complete | In-service |
| 4. | United States Line 3 Replacement Program | 100% | US$2.9 billion | US$1.3 billion | Pre-construction | Under review[3] |
| 5. | Other - United States[4] | 100% | US$0.6 billion | US$0.5 billion | Various stages | 2020 - 2021 |
| **GAS TRANSMISSION AND MIDSTREAM** | | | | | | |
| 6. | Atlantic Bridge[5] | 100% | US$0.6 billion | US$0.5 billion | Various stages | 2H - 2020 |
| 7. | Spruce Ridge Project | 100% | $0.5 billion | $0.2 billion | Pre-construction | 2H - 2021 |
| 8. | T-South Reliability & Expansion Program | 100% | $1.0 billion | $0.4 billion | Pre-construction | 2H - 2021 |
| 9. | Other - United States[6] | Various | US$1.2 billion | US$0.5 billion | Various stages | 2020 - 2023 |
| **GAS DISTRIBUTION AND STORAGE** | | | | | | |
| 10. | Other - Canada | 100% | $0.2 billion | No significant expenditures to date | Pre-construction | 2H - 2020 |
| 11. | Dawn-Parkway Expansion | 100% | $0.2 billion | No significant expenditures to date | Pre-construction | 2H - 2021 |
| **RENEWABLE POWER GENERATION** | | | | | | |
| 12. | Hohe See Offshore Wind Project and Expansion | 25% | $1.1 billion (€0.67 billion) | $0.9 billion (€0.6 billion) | Complete | In-service |
| 13. | East-West Tie Line | 25% | $0.2 billion | No significant expenditures to date | Under construction | 2H - 2021 |
| 14. | Saint-Nazaire Offshore Wind Project[7] | 50% | $1.8 billion (€1.2 billion) | $0.1 billion (€0.04 billion) | Under construction | 2H - 2022 |

*1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.*

*2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2019.*

*3 Update to in-service date pending receipt of all permits required to commence construction.*

*4 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.*

*5 Includes Connecticut and New York portions of the project that were placed into service in 2017 and in the fourth quarter of 2019, respectively.*

*6 Includes the US$0.2 billion Stratton Ridge Project placed into service in the second quarter of 2019 and the US$0.1 billion Generation Pipeline Acquisition closed in the third quarter of 2019.*

*7 Our equity contribution is $0.3 billion, with the remainder of the project financed through non-recourse project level debt.*

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors.*

**LIQUIDS PIPELINES**

The following commercially secured growth projects were acquired or placed into service in 2019:

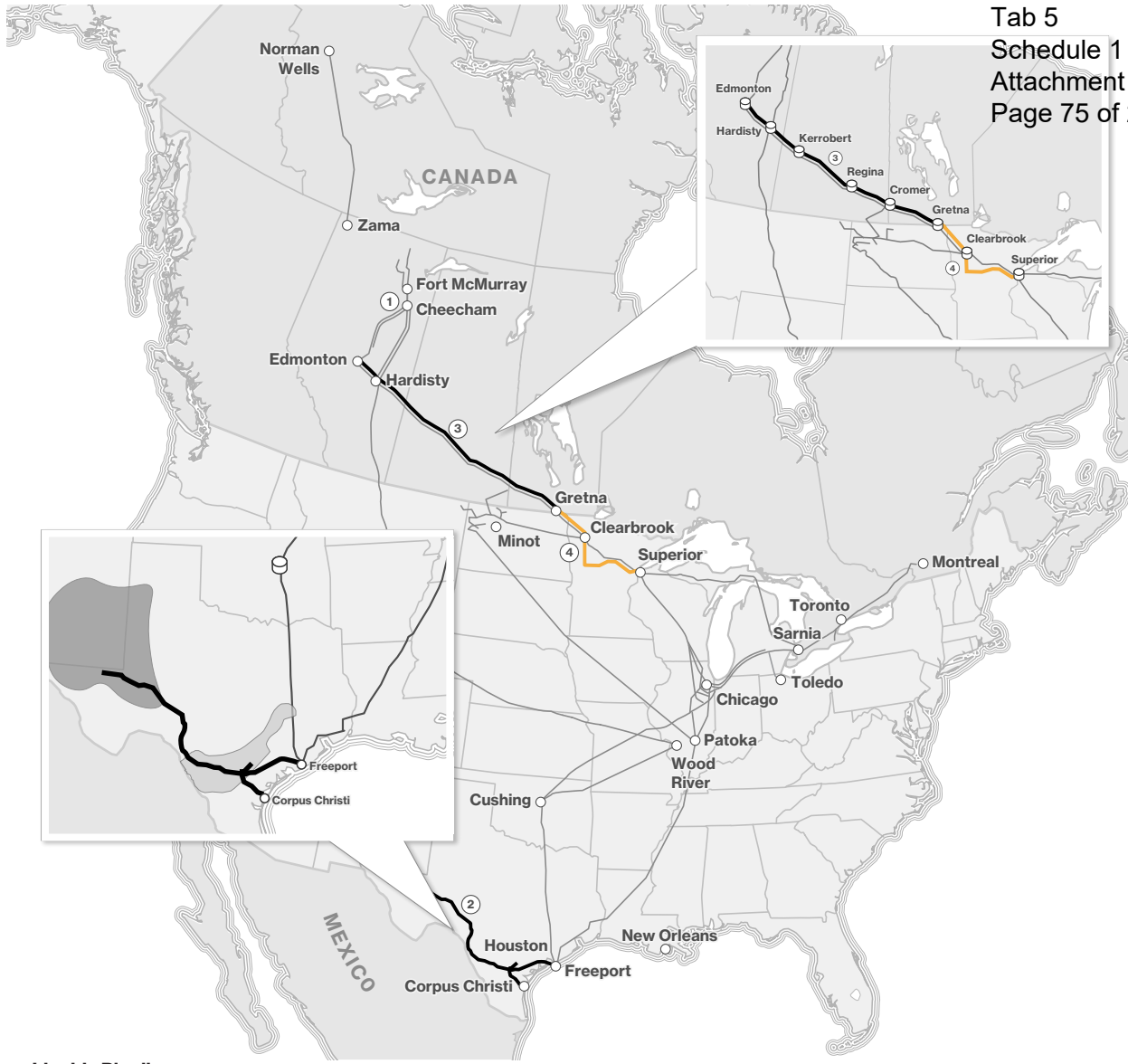
- **AOC Lateral Acquisition** - in January 2019, we acquired 75-kilometers (47-miles) of existing lateral pipelines and tankage infrastructure supporting Athabasca Oil Corporation's (AOC's) Leismer oil sands asset.

- **Gray Oak Pipeline Project -** a crude oil pipeline project connecting the Permian Basin and Eagle Ford to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 bpd, subject to additional shipper commitments. Initial in-service for the pipeline commenced in November 2019 with full in-service expected in the second quarter of 2020.

- **Canadian Line 3 Replacement Program -** replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. This will support the safety and operational reliability of the overall system, enhancing flexibility and allowing us to optimize throughput from western Canada into Superior, Wisconsin.

At this time, we cannot determine when all necessary permits will be issued for the following project:

- **United States Line 3 Replacement Program** - replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin. The U.S. L3R Program will support the safety and operational reliability of the Mainline System, enhance system flexibility and allow us to optimize throughput on the mainline. The U.S. L3R Program is expected to achieve the original capacity of approximately 760,000 bpd. The Wisconsin portion of the U.S. L3R Program is in service. For additional updates on the project, refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.




**Liquids Pipelines**

1 AOC Lateral Acquisition

2 Gray Oak Pipeline Project

3 Canadian Line 3 Replacement Program

4 United States Line 3 Replacement Program

- Assets in Operation
- Projects Placed into Service in 2019
- Growth Projects

**GAS TRANSMISSION AND MIDSTREAM**

The following commercially secured growth project is expected to be placed into service in 2020:

- **Atlantic Bridge -** expansion of the Algonquin natural gas transmission systems to transport 133 million cubic feet per day (mmcf/d) of natural gas to the New England Region. The expansion primarily consists of various meter station additions, the replacement of a natural gas pipeline in Connecticut and New York, compression additions in Connecticut and a new compressor station in Massachusetts. The meter stations were placed into service in 2017 and 2018. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The New York portion of the project achieved partial in-service in November 2018 and reached full in-service in October 2019, upon which we began earning incremental revenues. Due to ongoing permitting delays in Massachusetts, the revised expected in service date for the Massachusetts portion of the project is the second half of 2020.

The following commercially secured growth projects are expected to be placed into service in 2021:

- **Spruce Ridge Project** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in northern BC. The project will provide additional capacity of up to 402 mmcf/d. Due to commercial delays, the revised expected in-service date is the second half of 2021.

- **T-South Reliability & Expansion Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in southern BC that will provide improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/ Canada border. The projects were approved by the CER in September 2019.

**Gas Transmission**

**6** Atlantic Bridge

**7** Spruce Ridge Project

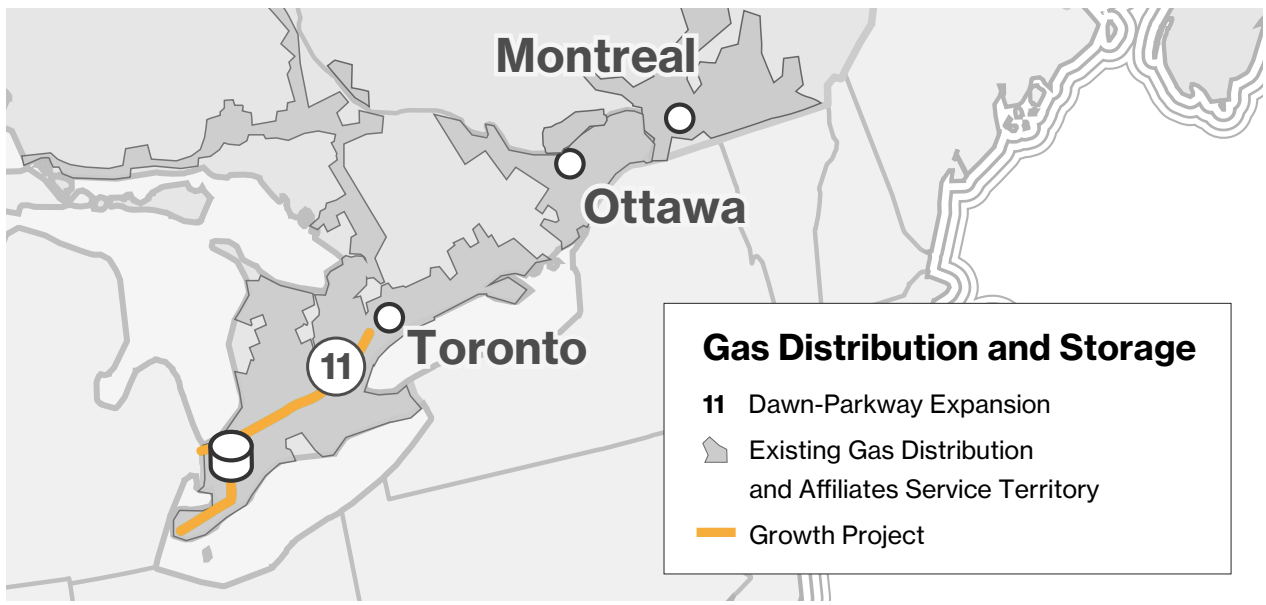
**8** T-South Reliability & Expansion Program

Assets in Operation
Growth Projects
Gas Plants in Operation

**GAS DISTRIBUTION AND STORAGE**

The following commercially secured growth project is expected to be placed into service in 2021:

- **Dawn-Parkway Expansion** - the expansion of the existing Dawn to Parkway gas transmission system, which provides transportation service from Dawn to the Greater Toronto Area. The project is expected to provide additional capacity of approximately 83 mmcf/d.




**RENEWABLE POWER GENERATION**

The following commercially secured growth project was placed into service in 2019:

- **Hohe See Offshore Wind Project and Expansion** - a wind project located in the North Sea, off the coast of Germany that will generate approximately 497-MW, with an additional 112-MW from the expansion. The Hohe See Project and Expansion is backed by a government legislated 20-year revenue support mechanism. The project generated first power in July 2019, and full operating capacity was reached in October 2019. The project expansion came into service in January 2020.

The following commercially secured growth project is expected to be placed into service in 2021:

- **East-West Tie Line** - a transmission project that will parallel an existing double-circuit, 230 kilovolt transmission line that connects the Wawa Transformer Station to the Lakehead Transformer Station near Thunder Bay, Ontario, including a connection midway in Marathon, Ontario.

The following commercially secured growth projects are expected to be placed into service in 2022:

- **Saint-Nazaire Offshore Wind Project -** a wind project located off the west coast of France that is expected to generate approximately 480-MW. Project revenues are backed by a 20-year fixed price power purchase agreement with added power production protection. Our share of the total investment in the project is $1.8 billion, with an equity contribution of $0.3 billion. The remainder of the construction will be financed through non-recourse project level debt.

**Renewable Power Generation**

**12** Hohe See Offshore Wind Project and Expansion

**13** East-West Tie Line Project

**14** Saint-Nazaire Offshore Wind Project

- Power Transmission in Operation
- Growth Projects – Power Transmission
- Wind Projects Placed Into Service in 2019
- Wind Assets in Operation
- Solar Assets in Operation
- Growth Projects – Wind

## GROWTH PROJECTS - REGULATORY MATTERS

**United States Line 3 Replacement Program**

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the MNPUC's adequacy determination of the FEIS for the U.S. L3R Program. While denying eight of the nine issues on appeal, the Minnesota Court of Appeals identified one issue that led it to reverse the adequacy determination. The Minnesota Court of Appeals remanded and directed the MNPUC to perform spill modeling analysis within the Lake Superior Watershed. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents' petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019. The Department of Commerce issued the revised FEIS on December 9, 2019 and the MNPUC gathered public comment on that document through January 16, 2020. On February 3, 2020, the MNPUC approved the adequacy of the revised FEIS and reinstated the Certificate of Need and Route Permit, clearing the way for construction of the pipeline to commence following the issuance of required permits.

As for environmental permits, the spill modeling required by the Minnesota Court of Appeals is a prerequisite to finalizing other state permits. On September 27, 2019, the Minnesota Pollution Control Agency (MPCA) issued a denial without prejudice of the U.S. L3R Program's 401 Water Quality Certification (WQC). This action was expected since the MPCA is prohibited by state law from issuing a final 401 WQC until the FEIS is found to be adequate by the MNPUC. On November 15, 2019, we submitted a revised 401 WQC to the MPCA. The MPCA is expected to release a draft of the revised 401 WQC on February 26, 2020, and a 30-day public comment period is expected to begin on March 2, 2020.

At this time, we cannot determine when all necessary permits to commence construction will be issued. Depending on the final in-service date, there is a risk that the project may exceed our total cost estimate of $9 billion for the combined Line 3 Replacement Program. However, at this time, we do not anticipate any capital cost impacts that would be material to our financial position and outlook.

## OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by us, but have not yet met our criteria to be classified as commercially secured:

**LIQUIDS PIPELINES**

- **Sea Port Oil Terminal Project -** the Sea Port Oil Terminal (SPOT) project consists of onshore and offshore facilities, including a fixed platform located approximately 30 miles off the coast of Brazoria County, Texas. SPOT is designed to load very large crude carriers at rates of approximately 85,000 barrels per hour, or up to approximately 2 million bpd. Along with Enterprise Products Partners, L.P., we announced our intent to jointly develop and market SPOT, and we will work to finalize an equity participation agreement. The agreement will allow us to purchase an ownership interest in SPOT, subject to SPOT receiving a deep-water port license.

- **Jones Creek Crude Oil Storage Terminal -** the Jones Creek terminal is expected to have an ultimate capability of up to 15 million barrels of storage, access to crude oil from all major North American production basins and will be fully integrated with the Seaway Pipeline system to allow for access to Houston-area refineries, existing export facilities, the SPOT project and other facilities in the future.

**GAS TRANSMISSION AND MIDSTREAM**

- **Rio Bravo Pipeline -** the Rio Bravo Pipeline is designed to transport up to 4.5 bcf/d of natural gas from the Agua Dulce supply area to NextDecade's Rio Grande LNG export facility in the Port of Brownsville, Texas. We have executed an agreement with NextDecade to acquire the Rio Bravo Pipeline development project. In addition, we have negotiated a precedent agreement with NextDecade, to be executed at closing, under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least twenty years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.

- **Annova LNG -** we have executed a precedent agreement to supply the Annova LNG facilities in the Port of Brownsville, Texas for a term of at least twenty years, by expanding our existing Valley Crossing system. The expansion will be subject to the Annova LNG facilities reaching a final investment decision.

- **Texas Eastern Venice Extension Project -** a reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.26 bcf of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The project is expected to be placed into service in 2022.

**RENEWABLE POWER GENERATION**

- **Éolien Maritime France SAS** - a 50% interest in EMF, a French offshore wind development company, which is co-owned by EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind facilities off the coast of France that is expected to generate approximately 1,428 MW. One wind facility, the Saint-Nazaire Offshore Wind Project, achieved a positive final investment decision during the third quarter of 2019. The development of the remaining two wind facilities is subject to final investment decisions and regulatory approvals, the timing of which are not yet certain.

We also have a large portfolio of additional projects under development that have not yet progressed to the point of public announcement.

## LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of additional common equity and was the leading principle behind the suspension of our Dividend Reinvestment and Share Purchase Plan in November 2018.

**CAPITAL MARKET ACCESS**

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan we completed the following issuances in 2019:

| Entity | Type of Issuance | Amount |
|---|---|---|
| *(in millions of Canadian dollars, unless stated otherwise)* | | |
| Enbridge Inc. | Medium-term notes | $1,000 |
| Enbridge Inc. | US$ senior notes | US$2,000 |
| Enbridge Gas Inc. | Medium-term notes | $700 |
| Enbridge Pipelines Inc. | Medium-term notes | $1,200 |
| Spectra Energy Partners, LP[1] | US$ senior notes | US$500 |

*1 Issued through Algonquin Gas Transmission, LLC, an operating subsidiary of Spectra Energy Partners, LP (SEP).*

**Credit Facilities, Ratings and Liquidity**

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities at December 31, 2019:

| | Maturity | Total Facilities | Draws[1] | Available |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Enbridge Inc. | 2021-2024 | **6,993** | **5,210** | **1,783** |
| Enbridge (U.S.) Inc. | 2021-2024 | **7,132** | **1,734** | **5,398** |
| Enbridge Pipelines Inc. | 2021 | **3,000** | **2,030** | **970** |
| Enbridge Gas Inc. | 2021 | **2,000** | **898** | **1,102** |
| Total committed credit facilities | | **19,125** | **9,872** | **9,253** |

*1 Includes facility draws and commercial paper issuances that are back-stopped by the credit facility.*

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, Enbridge Gas, Enbridge Energy Partners, L.P. (EEP) and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and Enbridge Gas. As a result, our total credit facility availability increased by approximately $444 million.

On May 16, 2019, Enbridge Inc. entered into a three year, non-revolving, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

On July 18, 2019, Enbridge Inc. entered into a five year, non-revolving, bilateral credit facility for $500 million with an Asian bank.

In addition to the committed credit facilities noted above, we have $916 million of uncommitted demand facilities, of which $476 million were unutilized as at December 31, 2019. As at December 31, 2018, we had $807 million of uncommitted credit facilities, of which $548 million were unutilized.

As at December 31, 2019 and 2018, our net available liquidity totaled $9,901 million and $9,409 million, respectively. As at December 31, 2019, the liquidity was inclusive of $648 million of unrestricted cash and cash equivalents as reported on the Consolidated Statements of Financial Position (2018 - $518 million).

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2019, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Strong growth in internal cash flow, proceeds from non-core asset dispositions, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

During 2019, our credit ratings were affirmed as follows:

- On July 23, 2019, DBRS Limited affirmed our issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), all with stable outlooks.
- On April 15, 2019, Fitch Rating services affirmed long-term issuer default rating and senior unsecured debt rating of BBB+, preference share rating of BBB-, junior subordinated note rating of BBB-, and short-term and commercial paper rating of F2 with a stable rating outlook.
- On January 25, 2019, Moody’s Investor Services, Inc. upgraded our issuer and senior unsecured ratings from Baa3 to Baa2 with outlook revised to positive, upgraded our subordinated rating from Ba2 to Ba1, preference share rating from Ba2 to Ba1 and the commercial paper rating for Enbridge (U.S.) Inc. from P-3 to P-2.
- On December 30, 2019, Standard & Poor’s Rating Services (S&P) affirmed our corporate credit rating and senior unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed our global overall short-term rating of A-2.

We invest surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties. Short-term investments were $2 million as at December 31, 2019 compared with $76 million as at December 31, 2018.

There are no material restrictions on our cash. Total restricted cash of $28 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2019 and 2018, we had a negative working capital position of $2,781 million and $3,024 million, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

**SOURCES AND USES OF CASH**

| December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Operating activities | **9,398** | 10,502 | 6,658 |
| Investing activities | **(4,658)** | (3,017) | (11,037) |
| Financing activities | **(4,745)** | (7,503) | 3,476 |
| Effect of translation of foreign denominated cash and cash equivalents | **44** | 68 | (72) |
| Net increase/(decrease) in cash and cash equivalents and restricted cash | **39** | 50 | (975) |

Significant sources and uses of cash for the years ended December 31, 2019 and 2018 are summarized below:

**Operating Activities**

**2019**

- The decrease in cash flow provided by operations during 2019 was primarily driven by changes in operating assets and liabilities. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28. Changes in Operating Assets and Liabilities*.
- The factor above was partially offset by stronger contributions from our operating segments and contributions from new assets placed into service as discussed under *Results of Operations*.

**2018**

- The increase in cash flow provided by operations during 2018 was primarily driven by changes in operating assets and liabilities and stronger contributions from our operating segments.

**Investing Activities**

We continue with the execution of our growth capital program which is further described in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2019, 2018 and 2017 is set out below:

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Liquids Pipelines | **2,548** | 3,102 | 2,797 |
| Gas Transmission and Midstream | **1,695** | 2,578 | 3,883 |
| Gas Distribution and Storage | **1,100** | 1,066 | 1,177 |
| Renewable Power Generation | **23** | 33 | 321 |
| Energy Services | **2** | — | 1 |
| Eliminations and Other | **124** | 27 | 108 |
| Total capital expenditures | **5,492** | 6,806 | 8,287 |

**2019**

The increase in cash used in investing activities primarily resulted from the following factors:

- Lower proceeds from asset dispositions in 2019 compared with 2018. In 2019, the proceeds from dispositions reflects the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets, St. Lawrence Gas and EGNB. In 2018, the proceeds from dispositions reflects the sale of MOLP, a portion of our renewable assets and the provincially regulated portion of our Canadian natural gas gathering and processing businesses assets.
- The absence in 2019 of a distribution received from Sabal Trail in 2018 as a partial return of capital for construction and development costs previously funded by Sabal Trail's partners.

**2018**

The decrease in cash used in investing activities primarily resulted from the following factors:

- Higher proceeds from asset dispositions in 2018 compared with 2017 primarily due to the sale of MOLP, a portion of our renewable assets and the provincially regulated portion of our Canadian natural gas gathering and processing businesses assets in 2018.
- The absence in 2018 of the acquisition of an interest in the Bakken Pipeline System in 2017.

**Financing Activities**

**2019**

The decrease in cash used in financing activities primarily resulted from the following factors:

- Increased commercial paper and credit facility draws and increased long-term debt issued in 2019 compared with 2018, partially offset by higher repayments of maturing long-term debt.
- Decreased distributions to noncontrolling interests and redeemable noncontrolling interests in 2019 primarily as a result of the Sponsored Vehicles buy-in in the fourth quarter of 2018.
- The absence in 2019 of proceeds received from the sale of a portion of our interest in our Canadian and United States renewable assets to the Canada Pension Plan Investment Board (CPPIB) in the third quarter of 2018.
- The above factors were partially offset by higher common share dividend payments in 2019 due to the increase in the common share dividend rate and an increase in the number of common shares outstanding in connection with the Sponsored Vehicles buy-in in the fourth quarter of 2018.

**2018**

The increase in cash used in financing activities primarily resulted from the following factors:

- Decreased long-term debt issuances and common shares issued in 2018 when compared with 2017, partially offset by lower repayments of maturing long-term debt.
- Higher common share dividend payments in 2018 due to the increase in the common share dividend rate and an increase in the number of common shares outstanding as a result of common shares issued in connection with the Merger Transaction and the issuance of approximately 33 million common shares in December 2017 in a private placement offering.
- Proceeds received from the sale of a portion of our interest in our Canadian and United States renewable assets to the CPPIB in the third quarter of 2018.
- Decreased contributions from noncontrolling interests and redeemable noncontrolling interests in 2018 primarily due to a secondary public offering in 2017 attributable to our holdings in Enbridge Income Fund Holdings Inc. (ENF).

**Preference Share Issuances**

Since July 2011, we have issued 315 million preference shares for gross proceeds of approximately $7.9 billion with the following characteristics.

| | Gross Proceeds | Dividend Rate | Dividend[1] | Per Share Base Redemption Value[2] | Redemption and Conversion Option Date[2,3] | Right to Convert Into[3,4] |
|---|---|---|---|---|---|---|
| *(Canadian dollars, unless otherwise stated)* | | | | | | |
| Series A | $125 million | 5.50% | $1.37500 | $25 | — | — |
| Series B | $457 million | 3.42% | $0.85360 | $25 | June 1, 2022 | Series C |
| Series C[5] | $43 million | 3-month treasury bill plus 2.40% | — | $25 | June 1, 2022 | Series B |
| Series D[6] | $450 million | 4.46% | $1.11500 | $25 | March 1, 2023 | Series E |
| Series F[6] | $500 million | 4.69% | $1.17224 | $25 | June 1, 2023 | Series G |
| Series H[6] | $350 million | 4.38% | $1.09400 | $25 | September 1, 2023 | Series I |
| Series J | US$200 million | 4.89% | US$1.22160 | US$25 | June 1, 2022 | Series K |
| Series L | US$400 million | 4.96% | US$1.23972 | US$25 | September 1, 2022 | Series M |
| Series N[6] | $450 million | 5.09% | $1.27152 | $25 | December 1, 2023 | Series O |
| Series P | $400 million | 4.38% | $1.09476 | $25 | March 1, 2024 | Series Q |
| Series R | $400 million | 4.07% | $1.01825 | $25 | June 1, 2024 | Series S |
| Series 1[6] | US$400 million | 5.95% | US$1.48728 | US$25 | June 1, 2023 | Series 2 |
| Series 3 | $600 million | 3.74% | $0.93425 | $25 | September 1, 2024 | Series 4 |
| Series 5 | US$200 million | 5.38% | US$1.34383 | US$25 | March 1, 2024 | Series 6 |
| Series 7 | $250 million | 4.45% | $1.11224 | $25 | March 1, 2024 | Series 8 |
| Series 9 | $275 million | 4.10% | $1.02424 | $25 | December 1, 2024 | Series 10 |
| Series 11 | $500 million | 4.40% | $1.10000 | $25 | March 1, 2020 | Series 12 |
| Series 13 | $350 million | 4.40% | $1.10000 | $25 | June 1, 2020 | Series 14 |
| Series 15 | $275 million | 4.40% | $1.10000 | $25 | September 1, 2020 | Series 16 |
| Series 17 | $750 million | 5.15% | $1.28750 | $25 | March 1, 2022 | Series 18 |
| Series 19 | $500 million | 4.90% | $1.22500 | $25 | March 1, 2023 | Series 20 |

*1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.*

*2 Series A Preference Shares may be redeemed any time at our option. For all other series of Preference Shares, we, may at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

*3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

*4 With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x 90 day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US$25 x (number of days in quarter/365) x three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

*5 The floating quarterly dividend amount for the Series C Preference Shares was decreased to $0.25395 from $0.25459 on March 1, 2019, was increased to $0.25647 from $0.25395 on June 1, 2019, was decreased to $0.25243 from $0.25647 on September 1, 2019 and was increased to $0.25305 from $0.25243 on December 1, 2019, due to reset on a quarterly basis following the issuance thereof.*

*6 No Series P, R, 3, 5, 7 or 9 Preference shares were converted on the March 1, 2019, June 1, 2019, September 1, 2019, March 1, 2019, March 1, 2019 or December 1, 2019 conversion option dates, respectively. However, the quarterly dividend amounts for Series P, R, 3, 5, 7 or 9, was increased to $0.27369 from $0.25000 on March 1, 2019, increased to $0.25456 from $0.25000 on June 1, 2019, decreased to $0.23356 from $0.25000 on September 1, 2019, increased to US$0.33625 from US$0.27500 on March 1, 2019, increased to $0.27806 from $0.27500 on March 1, 2019 and decreased to $0.25606 from $0.27500 on December 1, 2019, respectively, due to reset on every fifth anniversary thereafter.*

**Common Share Issuances**

In the fourth quarter of 2018, we completed the issuance of 297 million common shares with a value of $12.7 billion in connection with the Sponsored Vehicles buy-in. For further information refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 21. Share Capital.*

**Dividends**

For the years ended December 31, 2019 and 2018, total dividends paid were $5,973 million and $4,661 million, respectively, of which $5,973 million and $3,480 million, respectively, were paid in cash and reflected in financing activities. In 2018, $1,181 million of dividends paid were reinvested pursuant to our previous dividend reinvestment program and resulted in the issuance of common shares rather than a cash payment.

On December 9, 2019, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2020 to shareholders of record on February 14, 2020.

| | |
|---|---|
| Common Shares[1] | $0.81000 |
| Preference Shares, Series A | $0.34375 |
| Preference Shares, Series B | $0.21340 |
| Preference Shares, Series C[2] | $0.25305 |
| Preference Shares, Series D | $0.27875 |
| Preference Shares, Series F | $0.29306 |
| Preference Shares, Series H | $0.27350 |
| Preference Shares, Series J | US$0.30540 |
| Preference Shares, Series L | US$0.30993 |
| Preference Shares, Series N | $0.31788 |
| Preference Shares, Series P[3] | $0.27369 |
| Preference Shares, Series R[4] | $0.25456 |
| Preference Shares, Series 1 | US$0.37182 |
| Preference Shares, Series 3[5] | $0.23356 |
| Preference Shares, Series 5[6] | US$0.33596 |
| Preference Shares, Series 7[7] | $0.27806 |
| Preference Shares, Series 9[8] | $0.25606 |
| Preference Shares, Series 11 | $0.27500 |
| Preference Shares, Series 13 | $0.27500 |
| Preference Shares, Series 15 | $0.27500 |
| Preference Shares, Series 17 | $0.32188 |
| Preference Shares, Series 19 | $0.30625 |

1 *The quarterly dividend per common share was increased 9.8% to $0.81000 from $0.73800, effective March 1, 2020.*

2 *The quarterly dividend per share paid on Series C was decreased to $0.25395 from $0.25459 on March 1, 2019, increased to $0.25647 from $0.25395 on June 1, 2019, decreased to $0.25243 from $0.25647 on September 1, 2019, and increased to $0.25305 from $0.25243 on December 1, 2019, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.*

3 *The quarterly dividend per share paid on Series P was increased to $0.27369 from $0.25000 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

4 *The quarterly dividend per share paid on Series R was increased to $0.25456 from $0.25000 on June 1, 2019, due to the reset of the annual dividend on June 1, 2019, and every five year thereafter.*

5 *The quarterly dividend per share paid on Series 3 was decreased to $0.23356 from $0.25000 on September 1, 2019, due to the reset of the annual dividend on September 1, 2019, and every five year thereafter.*

6 *The quarterly dividend per share paid on Series 5 was increased to US $0.33596 from US $0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

7 *The quarterly dividend per share paid on Series 7 was increased to $0.27806 from $0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

8 *The quarterly dividend per share paid on Series 9 was decreased to $0.25606 from $0.27500 on December 1, 2019, due to the reset of the annual dividend on December 1, 2019, and every five years thereafter.*

**OFF-BALANCE SHEET ARRANGEMENTS**

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Guarantees* for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Statements of Financial Position. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events. Issuance of these guarantee arrangements is not required for the majority of our operations.

We do not have material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies* and *Note 31. Guarantees*.

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

**CONTRACTUAL OBLIGATIONS**

Payments due under contractual obligations over the next five years and thereafter are as follows:

| As at December 31, 2019 | Total | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Annual debt maturities[1] | 63,585 | 4,394 | 10,910 | 10,297 | 37,984 |
| Interest obligations[2] | 29,498 | 2,416 | 4,512 | 3,991 | 18,579 |
| Land leases | 1,190 | 30 | 70 | 71 | 1,019 |
| Pension obligations[3] | 135 | 135 | — | — | — |
| Long-term contracts[4] | 9,883 | 2,947 | 2,832 | 1,179 | 2,925 |
| Other long-term liabilities[5] | — | — | — | — | — |
| Total contractual obligations | 104,291 | 9,922 | 18,324 | 15,538 | 60,507 |

*1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discount, debt issue costs and finance lease obligations. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

*2 Includes debentures and term notes bearing interest at fixed, floating and fixed-to-floating rates.*

*3 Assumes only required payments will be made into the pension plans in 2019. Contributions are made in accordance with independent actuarial valuations as at December 31, 2019. Contributions, including discretionary payments, may vary depending on future benefit design and asset performance.*

*4 Included within long-term contracts, in the table above, are contracts that we have signed for the purchase of services, pipe and other materials totaling $2,237 million which are expected to be paid over the next five years. Also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.*

*5 We are unable to estimate deferred income taxes (Part II. Item 8. Financial Statements and Supplementary Data - Note 25. Income Taxes) since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year. We are also unable to estimate asset retirement obligations (ARO) (Part II. Item 8. Financial Statements and Supplementary Data - Note 19. Asset Retirement Obligations), environmental liabilities (Part II. Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies) and hedges payable (Part II. Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments) due to the uncertainty as to the amount and, or, timing of when cash payments will be required.*

# LEGAL AND OTHER UPDATES

**LIQUIDS PIPELINES**

**Eddystone Rail Legal Matter**

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania, seeking damages in excess of US$140 million. On September 7, 2018, the United States District Court for the Eastern District of Pennsylvania granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants (the Amended Complaint). Eddystone Rail's chances of success on its Amended Complaint cannot be predicted at this time. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US$32 million. The defendants' chances of success on their counterclaims cannot be predicted at this time. The non-corporate defendants filed a Motion to Dismiss on October 25, 2019, based on alleged lack of standing. The motion has been fully briefed to the Court and decision is pending. The individual defendants' chances of success on this motion cannot be predicted at this time.

**Dakota Access Pipeline**

In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the United States Court for the District of Columbia contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline. The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corps permit and environmental review process. In August 2018, in response to a Court order to reconsider components of its environmental analysis, the Army Corps issued its decision that no supplemental environmental analysis was required. All four Tribes have since amended their complaints to include claims challenging the adequacy of the Army Corps' supplemental environmental analysis. The parties have filed cross-motions for summary judgment with the United States District Court for the District of Columbia on the merits of the plaintiffs claims challenging the adequacy of the Army Corps' remand process. Briefing on the parties' cross-motions for summary judgment was completed on November 25, 2019. These cross-motions remain pending for decision before the District Court.

**Line 5 Dual Pipelines**

In December 2018, Michigan law PA 359 was enacted which created the Mackinac Straits Corridor Authority (Corridor Authority) and authorized an agreement between us and the Corridor Authority for the construction of a tunnel under the Straits of Mackinac (Straits) to house a replacement for the Line 5 Dual Pipelines that currently cross the Straits (the Tunnel Project). On December 19, 2018, we entered into a Tunnel Project agreement with the Government of Michigan. On March 28, 2019, the Michigan Attorney General issued an opinion finding the Michigan law PA 359 unconstitutional and soon after, Michigan Governor Whitmer issued a directive to Michigan agencies to cease any action implementing the statute.

To resolve the legal uncertainty created by the Michigan Attorney General's opinion and the directive issued by Michigan Governor Whitmer, on June 6, 2019, we filed a complaint with the Michigan Court of Claims to establish the constitutional validity of Michigan law PA 359 and enforceability of various agreements entered into between us and the State of Michigan related to the construction of the Tunnel Project. On June 11, 2019, State officials confirmed that we had valid permits to conduct specified geotechnical work which has now been completed. This work was necessary to prepare for Tunnel Project construction. On June 27, 2019, the Michigan Attorney General requested the Michigan Court of Claims to dismiss our complaint and we opposed her request with our response filed on August 1, 2019. On October 31, 2019, the Michigan Court of Claims determined that Michigan law PA 359 is valid and is not unconstitutional. On November 5, 2019 the Michigan Attorney General filed an appeal of this decision. According to the expedited appeal schedule, briefing is anticipated to be completed in March 2020 with a decision expected later in 2020.

On June 27, 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court that requests the Court to declare the easement that we have for the operation of the dual pipelines in the Straits to be invalid and to prohibit continued operation of the dual pipelines in the Straits "as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties". We continue to vigorously defend this action and on September 16, 2019, we filed our motion for summary disposition and requested dismissal of the State's Complaint in its entirety. On that same date, the State filed a motion for partial summary disposition and judgment in its favor on its claim that the easement was void from inception. The case is now fully briefed. Oral argument on the parties' motions has been scheduled for May 22, 2020.

**Line 5 Easement**

For over six years, we have been in negotiations and discussions with the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) to resolve the Band's concerns over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. These negotiations and discussions did not resolve the Band's concerns. On July 23, 2019, the Band filed a complaint in the United States District Court for the Western District of Wisconsin alleging that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and also alleging that the pipeline is in trespass on certain tracts of land in which the Band possesses undivided ownership interests. The Band also seeks an order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. On September 24, 2019, in response to the Band's complaint, we filed an answer, defenses, and counterclaims against the Band, as well as a motion to dismiss. On October 15, 2019, the Band filed its first amended complaint against us, adding new assertions about allegedly unsafe conditions at a specific location of the pipeline on the Reservation and requesting a declaration by the court that the Band has regulatory authority over Line 5. On October 29, 2019, we filed our response, defenses and counterclaims to the Band's first amended complaint. A trial date has been set for July 2021.

The Band has not sought a temporary injunction to immediately discontinue operation of Line 5. However, if successful, the Band's lawsuit could impact our ability to operate the pipeline on the Reservation. We have been vigorously defending the Band's action since it was filed and will continue to do so. Nevertheless, we also plan to continue working with the Band in an effort to address its concerns, and at the same time, as a contingency measure, we have begun taking steps to enable the construction of a reroute of Line 5 around the Reservation. To that end, we have identified a proposed route outside the Reservation and, on February 7, 2020, we initiated the permitting process for the proposed reroute by filing applications with federal and state regulatory authorities.

**GAS TRANSMMISSION**

**DCP Midstream, LP Definitive Agreement and Equity Restructuring**

On November 6, 2019 DCP Midstream, LP (DCP MLP) announced the execution of a definitive agreement with its general partner, in which we indirectly own a 50% equity interest, and the concurrent closing of an equity restructuring transaction. The transaction resulted in the general partner converting all of its incentive distribution rights in DCP MLP, which were eliminated, and its 2% economic general partner interest in DCP MLP, while retaining a non-economic general partner interest, into newly-issued DCP MLP common units. As a result of this transaction, we increased our indirect ownership of outstanding DCP MLP common units from approximately 18% to approximately 28%, while retaining our indirect 50% ownership interest in the general partner of DCP MLP.

**OTHER LITIGATION**

We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

**TAX MATTERS**
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

## CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

**Business Combinations**
We apply the provisions of Accounting Standards Codification (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

On February 27, 2017, we acquired Spectra Energy for a purchase price of $37.5 billion. In determining the valuation of tangible assets acquired, we applied the cost, market and income approaches. For intangible assets acquired, we used an income approach which included cash flow projections based on historical performance, terms found in contracts and assumptions on expected renewals. Discount rates used in the valuation were also developed using a weighted-average cost of capital based on risks specific to respective assets and returns that an investor would likely require given the expected cash flows, timing and risk.

**Goodwill Impairment**
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than it's carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each corresponding reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

Our most recent annual review of the goodwill balance was performed on April 1, 2019, and this review did not result in an impairment charge. As at April 1, 2019, our reporting units were equivalent to our reportable segments, except for the Gas Transmission and Midstream reportable segment which was divided at the component level into two reporting units: Gas Transmission and Gas Midstream. We performed a quantitative goodwill impairment test of our Gas Midstream reporting unit. We elected to perform qualitative assessments of our Liquids Pipelines, Gas Distribution and Storage, and Gas Transmission and Midstream reporting units and concluded it was not more likely than not that these reporting units were impaired and that quantitative impairment tests were not necessary.

The allocation of goodwill to held for sale and disposed businesses is based on the fair value of businesses relative to their corresponding reporting unit. During the years ended December 31, 2019, and 2018, we impaired nil and $1,019 million, respectively, of goodwill allocated to assets held for sale.

**Asset Impairment**
We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.

**Assets held for sale**
We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

**Regulatory Accounting**

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the CER, the FERC, the Alberta Energy Regulator, La Régie de l'energie du Québec and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including operating costs, capital invested and depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Interest costs on the debt component of the capital structure; and
- Contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2019 and 2018, our significant regulatory assets totaled $4,800 million and $4,695 million, respectively, and significant regulatory liabilities totaled $2,786 million and $2,363 million, respectively.

**Depreciation**

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2019 and 2018, of $93,723 million and $94,540 million, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

**Pension and Other Postretirement Benefits**

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2019 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions:

| | Canada | | United States | |
|---|---|---|---|---|
| | Obligation | Expense | Obligation | Expense |
| *(millions of Canadian dollars)* | | | | |
| **Pension** | | | | |
| Decrease in discount rate | 368 | 34 | 69 | 6 |
| Decrease in expected return on assets | — | 18 | — | 5 |
| Decrease in rate of salary increase | (66) | (15) | (7) | (1) |
| **OPEB** | | | | |
| Decrease in discount rate | 23 | 1 | 15 | — |
| Decrease in expected return on assets | — | — | — | 1 |

**Contingent Liabilities**

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

**Asset Retirement Obligations**
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. Discount rates used to estimate the present value of the expected future cash flows range from 1.8% to 9.0% for the years ended December 31, 2019 and 2018. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

## CHANGES IN ACCOUNTING POLICIES

Refer to *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies*.

# ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

**Foreign Exchange Risk**
We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

**Interest Rate Risk**
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As at December 31, 2019, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3%.

**Commodity Price Risk**
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

**Equity Price Risk**
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

**Market Risk Management**
We have a Risk Policy to minimize the likelihood that adverse cash flow impacts arising from movements in market prices will exceed a defined risk tolerance. We identify and measure all material market risks including commodity price risks, interest rate risks, foreign exchange risk and equity price risk using a standardized measurement methodology. Our market risk metric consolidates the exposure after accounting for the impact of offsetting risks and limits the consolidated cash flow volatility arising from market related risks to an acceptable approved risk tolerance threshold. Our market risk metric is Cash Flow at Risk (CFaR).

CFaR is a statistically derived measurement used to measure the maximum cash flow loss that could potentially result from adverse market price movements over a one month holding period for price sensitive non-derivative exposures and for derivative instruments we hold or issue as recorded on the Consolidated Statements of Financial Position as at December 31, 2019. CFaR assumes that no further mitigating actions are taken to hedge or otherwise minimize exposures and the selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. As a practical matter, a large portion of Enbridge's exposure could be hedged or unwound in a much shorter period if required to mitigate the risks.

The consolidated CFaR policy limit for Enbridge is 3.5% of its forward 12 month normalized cash flow. At December 31, 2019 and 2018 CFaR was $113 million and $140 million or 1.2% and 1.6%, respectively, of estimated 12 month forward normalized cash flow.

**LIQUIDITY RISK**

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or United States public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2019. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

**CREDIT RISK**

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements or other similar derivative agreements with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events, and reduces our credit risk exposure on financial derivative asset positions outstanding with the counterparties in these particular circumstances.

**FAIR VALUE MEASUREMENTS**

The most observable inputs available are used to estimate the fair value of derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices from exchanges. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest rates, foreign exchange rates, commodity prices and share prices, as applicable) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

# ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**Report of Independent Registered Public Accounting Firm**

To the Shareholders and Board of Directors of Enbridge Inc.

***Opinions on the Financial Statements and Internal Control over Financial Reporting***

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2019 and 2018, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

***Basis for Opinions***

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

***Definition and Limitations of Internal Control over Financial Reporting***

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

***Critical Audit Matters***

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

*Goodwill Impairment Review*

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $33,153 million at December 31, 2019. Management performs an annual goodwill impairment review at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends, and changes to industry conditions. The quantitative goodwill impairment test involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, revenue growth rates, terminal value growth rates, expected future capital expenditures and working capital levels. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units. In the current year, the quantitative goodwill impairment test was only performed for the Gas Midstream reporting unit.

The principal considerations for our determination that performing procedures relating to the goodwill impairment review is a critical audit matter are that there was significant judgment required by management when (i) developing the significant assumptions related to operating income trends used in the qualitative assessment for all reporting units outside of the Gas Midstream reporting unit, and (ii) developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures and earnings multipliers used to estimate the fair value of the Gas Midstream reporting unit. This in turn led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate (a) management's significant assumptions used in the qualitative assessment and

(b) the cash flow projections and significant assumptions used by management in their quantitative assessment of the Gas Midstream reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing the procedures and evaluating the audit evidence obtained over the quantitative assessment.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment review, including controls over (i) the development of assumptions related to operating income trends used in the qualitative assessment and (ii) the determination of the fair value estimate of the Gas Midstream reporting unit. These procedures also included, among others, evaluating the reasonableness of significant assumptions used by management in the qualitative assessment of the Company's reporting units, specifically those related to operating income trends, and testing management's process for developing the fair value estimate of the Gas Midstream reporting unit. Testing management's process for developing the fair value estimate of the Gas Midstream reporting unit included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness, accuracy, and relevance of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in developing the fair value measurement including discount rates, projected operating income, expected future capital expenditures and earnings multipliers. When assessing the reasonableness of projected operating income and its trends, and expected future capital expenditures, we evaluated whether these significant assumptions were reasonable considering the current and past performance of the Company's reporting units, external industry data, and evidence obtained in other areas of the audit. We utilized professionals with specialized skill and knowledge to assist in evaluating the appropriateness of management's discounted cash flow and earnings multiples models and evaluating the reasonableness of assumptions used in the models, specifically discount rates and earnings multiples.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada
February 14, 2020

We have served as the Company's auditor since 1949.

# ENBRIDGE INC.
# CONSOLIDATED STATEMENTS OF EARNINGS

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Operating revenues | | | |
| Commodity sales | **29,309** | 27,660 | 26,286 |
| Gas distribution sales | **4,205** | 4,360 | 4,215 |
| Transportation and other services | **16,555** | 14,358 | 13,877 |
| Total operating revenues *(Note 4)* | **50,069** | 46,378 | 44,378 |
| Operating expenses | | | |
| Commodity costs | **28,802** | 26,818 | 26,065 |
| Gas distribution costs | **2,202** | 2,583 | 2,572 |
| Operating and administrative | **6,991** | 6,792 | 6,442 |
| Depreciation and amortization | **3,391** | 3,246 | 3,163 |
| Impairment of long-lived assets *(Note 8 and Note 11)* | **423** | 1,104 | 4,463 |
| Impairment of goodwill *(Note 8 and Note 16)* | **—** | 1,019 | 102 |
| Total operating expenses | **41,809** | 41,562 | 42,807 |
| Operating income | **8,260** | 4,816 | 1,571 |
| Income from equity investments *(Note 13)* | **1,503** | 1,509 | 1,102 |
| Other income/(expense) | | | |
| Net foreign currency gain/(loss) | **477** | (522) | 237 |
| Gain/(loss) on dispositions | **(300)** | (46) | 16 |
| Other | **258** | 516 | 199 |
| Interest expense *(Note 18)* | **(2,663)** | (2,703) | (2,556) |
| Earnings before income taxes | **7,535** | 3,570 | 569 |
| Income tax recovery/(expense) *(Note 25)* | **(1,708)** | (237) | 2,697 |
| Earnings | **5,827** | 3,333 | 3,266 |
| Earnings attributable to noncontrolling interests and redeemable noncontrolling interests | **(122)** | (451) | (407) |
| Earnings attributable to controlling interests | **5,705** | 2,882 | 2,859 |
| Preference share dividends | **(383)** | (367) | (330) |
| Earnings attributable to common shareholders | **5,322** | 2,515 | 2,529 |
| Earnings per common share attributable to common shareholders *(Note 6)* | **2.64** | 1.46 | 1.66 |
| Diluted earnings per common share attributable to common shareholders *(Note 6)* | **2.63** | 1.46 | 1.65 |

The accompanying notes are an integral part of these consolidated financial statements.

# ENBRIDGE INC.
# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings | **5,827** | 3,333 | 3,266 |
| Other comprehensive income/(loss), net of tax | | | |
| Change in unrealized loss on cash flow hedges | **(437)** | (153) | (21) |
| Change in unrealized gain/(loss) on net investment hedges | **281** | (458) | 490 |
| Other comprehensive income/(loss) from equity investees | **40** | 38 | (27) |
| Reclassification to earnings of loss on cash flow hedges | **127** | 152 | 313 |
| Reclassification to earnings of pension and other postretirement benefits amounts | **13** | 12 | 19 |
| Actuarial gain/(loss) on pension plans and other postretirement benefits | **(96)** | (52) | 8 |
| Foreign currency translation adjustments | **(3,035)** | 4,599 | (3,060) |
| Other comprehensive income/(loss), net of tax | **(3,107)** | 4,138 | (2,278) |
| Comprehensive income | **2,720** | 7,471 | 988 |
| Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests | **(7)** | (801) | (160) |
| Comprehensive income attributable to controlling interests | **2,713** | 6,670 | 828 |
| Preference share dividends | **(383)** | (367) | (330) |
| Comprehensive income attributable to common shareholders | **2,330** | 6,303 | 498 |

The accompanying notes are an integral part of these consolidated financial statements.

**ENBRIDGE INC.**
**CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY**

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Preference shares *(Note 21)* | | | |
| Balance at beginning of year | **7,747** | 7,747 | 7,256 |
| Preference shares issued | **—** | — | 491 |
| Balance at end of year | **7,747** | 7,747 | 7,747 |
| Common shares *(Note 21)* | | | |
| Balance at beginning of year | **64,677** | 50,737 | 10,492 |
| Common shares issued | **—** | — | 1,500 |
| Common shares issued in Merger Transaction *(Note 8)* | **—** | — | 37,429 |
| Shares issued on Sponsored Vehicles buy-in *(Note 21)* | **—** | 12,727 | — |
| Dividend Reinvestment and Share Purchase Plan | **—** | 1,181 | 1,226 |
| Shares issued on exercise of stock options | **69** | 32 | 90 |
| Balance at end of year | **64,746** | 64,677 | 50,737 |
| Additional paid-in capital | | | |
| Balance at beginning of year | **—** | 3,194 | 3,399 |
| Stock-based compensation | **34** | 49 | 82 |
| Sponsored Vehicles buy-in (*Note 20)* | **—** | (4,323) | — |
| Repurchase of noncontrolling interest | **65** | — | — |
| Options exercised | **(61)** | (24) | (95) |
| Dilution gain on Spectra Energy Partners, LP restructuring *(Note 20)* | **—** | 1,136 | — |
| Change in reciprocal interest | **117** | 47 | — |
| Other | **32** | (158) | (192) |
| Sale of noncontrolling interest in subsidiaries *(Note 20)* | **—** | 79 | — |
| Balance at end of year | **187** | — | 3,194 |
| Retained earnings/(deficit) | | | |
| Balance at beginning of year | **(5,538)** | (2,468) | (716) |
| Earnings attributable to controlling interests | **5,705** | 2,882 | 2,859 |
| Preference share dividends | **(383)** | (367) | (330) |
| Common share dividends declared | **(6,125)** | (5,019) | (4,702) |
| Dividends paid to reciprocal shareholder | **18** | 33 | 30 |
| Modified retrospective adoption of *ASC 606 Revenue from Contracts with Customers* | **—** | (86) | — |
| Redemption value adjustment to redeemable noncontrolling interests *(Note 20)* | **—** | (456) | 292 |
| Other | **9** | (57) | 99 |
| Balance at end of year | **(6,314)** | (5,538) | (2,468) |
| Accumulated other comprehensive income/(loss) *(Note 23)* | | | |
| Balance at beginning of year | **2,672** | (973) | 1,058 |
| Impact of Sponsored Vehicles buy-in | **—** | (142) | — |
| Other comprehensive income/(loss) attributable to common shareholders, net of tax | **(2,992)** | 3,787 | (2,031) |
| Other | **48** | — | — |
| Balance at end of year | **(272)** | 2,672 | (973) |
| Reciprocal shareholding *(Note 13)* | | | |
| Balance at beginning of year | **(88)** | (102) | (102) |
| Change in reciprocal interest | **37** | 14 | — |
| Balance at end of year | **(51)** | (88) | (102) |
| Total Enbridge Inc. shareholders' equity | **66,043** | 69,470 | 58,135 |
| Noncontrolling interests *(Note 20)* | | | |
| Balance at beginning of year | **3,965** | 7,597 | 577 |
| Earnings attributable to noncontrolling interests | **122** | 334 | 232 |
| Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax | | | |
| Change in unrealized gain/(loss) on cash flow hedges | **(7)** | 31 | 15 |
| Foreign currency translation adjustments | **(108)** | 294 | (431) |
| Reclassification to earnings of loss on cash flow hedges | **—** | 4 | 139 |
| | **(115)** | 329 | (277) |
| Comprehensive income/(loss) attributable to noncontrolling interests | **7** | 663 | (45) |
| Noncontrolling interests resulting from Merger Transaction *(Note 8)* | **—** | — | 8,955 |
| Enbridge Energy Company, Inc. common control transaction | **—** | — | (343) |
| Distributions | **(254)** | (857) | (839) |
| Contributions | **12** | 24 | 832 |
| Deconsolidation of Sabal Trail Transmission, LLC | **—** | — | (2,318) |
| Spectra Energy Partners, LP restructuring *(Note 20)* | **—** | (1,486) | — |
| Sale of noncontrolling interests in subsidiaries | **—** | 1,183 | — |
| Change in noncontrolling interests on Sponsored Vehicles buy-in (*Note 20*) | **—** | (2,867) | — |
| Preferred shares redemption *(Note 20)* | **(300)** | (210) | — |
| Repurchase of noncontrolling interest | **(65)** | — | — |
| Dilution gain and other | **(1)** | (82) | 778 |
| Balance at end of year | **3,364** | 3,965 | 7,597 |
| Total equity | **69,407** | 73,435 | 65,732 |
| Dividends paid per common share | **2.95** | 2.68 | 2.41 |

The accompanying notes are an integral part of these consolidated financial statements.

# ENBRIDGE INC.
# CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Operating activities** | | | |
| Earnings | **5,827** | 3,333 | 3,266 |
| Adjustments to reconcile earnings to net cash provided by operating activities: | | | |
| Depreciation and amortization | **3,391** | 3,246 | 3,163 |
| Deferred income tax (recovery)/expense *(Note 25)* | **1,156** | (148) | (2,877) |
| Changes in unrealized (gain)/loss on derivative instruments, net *(Note 24)* | **(1,751)** | 903 | (1,242) |
| Earnings from equity investments | **(1,503)** | (1,509) | (1,102) |
| Distributions from equity investments | **1,804** | 1,539 | 1,264 |
| Impairment of long-lived assets | **423** | 1,104 | 4,463 |
| Impairment of goodwill | **—** | 1,019 | 102 |
| (Gain)/loss on dispositions | **254** | 8 | (120) |
| Other | **56** | 92 | 79 |
| Changes in operating assets and liabilities *(Note 28)* | **(259)** | 915 | (338) |
| Net cash provided by operating activities | **9,398** | 10,502 | 6,658 |
| **Investing activities** | | | |
| Capital expenditures | **(5,492)** | (6,806) | (8,287) |
| Long-term investments and restricted long-term investments | **(1,159)** | (1,312) | (3,586) |
| Distributions from equity investments in excess of cumulative earnings | **417** | 1,277 | 125 |
| Additions to intangible assets | **(200)** | (540) | (789) |
| Cash acquired in Merger Transaction *(Note 8)* | **—** | — | 682 |
| Proceeds from dispositions | **2,110** | 4,452 | 628 |
| Other | **(20)** | (12) | 212 |
| Affiliate loans, net | **(314)** | (76) | (22) |
| Net cash used in investing activities | **(4,658)** | (3,017) | (11,037) |
| **Financing activities** | | | |
| Net change in short-term borrowings *(Note 18)* | **(127)** | (420) | 721 |
| Net change in commercial paper and credit facility draws | **825** | (2,256) | (1,249) |
| Debenture and term note issues, net of issue costs | **6,176** | 3,537 | 9,483 |
| Debenture and term note repayments | **(4,668)** | (4,445) | (5,054) |
| Sale of noncontrolling interest in subsidiary | **—** | 1,289 | — |
| Purchase of interest in consolidated subsidiary | **—** | — | (227) |
| Contributions from noncontrolling interests | **12** | 24 | 832 |
| Distributions to noncontrolling interests | **(254)** | (857) | (919) |
| Contributions from redeemable noncontrolling interests | **—** | 70 | 1,178 |
| Distributions to redeemable noncontrolling interests | **—** | (325) | (247) |
| Sponsored Vehicle buy-in cash payment | **—** | (64) | — |
| Preference shares issued | **—** | — | 489 |
| Redemption of preferred shares | **(300)** | (210) | — |
| Common shares issued | **18** | 21 | 1,549 |
| Preference share dividends | **(383)** | (364) | (330) |
| Common share dividends | **(5,973)** | (3,480) | (2,750) |
| Other | **(71)** | (23) | — |
| Net cash (used in)/provided by financing activities | **(4,745)** | (7,503) | 3,476 |
| Effect of translation of foreign denominated cash and cash equivalents and restricted cash | **44** | 68 | (72) |
| Net increase/(decrease) in cash and cash equivalents and restricted cash | **39** | 50 | (975) |
| Cash and cash equivalents and restricted cash at beginning of year | **637** | 587 | 1,562 |
| Cash and cash equivalents and restricted cash at end of year | **676** | 637 | 587 |
| **Supplementary cash flow information** | | | |
| Cash paid for income taxes | **571** | 277 | 172 |
| Cash paid for interest, net of amount capitalized | **2,738** | 2,508 | 2,668 |
| Property, plant and equipment non-cash accruals | **730** | 847 | 889 |

The accompanying notes are an integral part of these consolidated financial statements.

# ENBRIDGE INC.
# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| December 31, | 2019 | 2018 |
|---|---|---|
| *(millions of Canadian dollars; number of shares in millions)* | | |
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents *(Note 2)* | **648** | 518 |
| Restricted cash | **28** | 119 |
| Accounts receivable and other *(Note 9)* | **6,781** | 6,517 |
| Accounts receivable from affiliates | **69** | 79 |
| Inventory *(Note 10)* | **1,299** | 1,339 |
| | **8,825** | 8,572 |
| Property, plant and equipment, net *(Note 11)* | **93,723** | 94,540 |
| Long-term investments *(Note 13)* | **16,528** | 16,707 |
| Restricted long-term investments *(Note 14)* | **434** | 323 |
| Deferred amounts and other assets | **7,433** | 8,558 |
| Intangible assets, net *(Note 15)* | **2,173** | 2,372 |
| Goodwill *(Note 16)* | **33,153** | 34,459 |
| Deferred income taxes *(Note 25)* | **1,000** | 1,374 |
| Total assets | **163,269** | 166,905 |
| | | |
| **Liabilities and equity** | | |
| Current liabilities | | |
| Short-term borrowings *(Note 18)* | **898** | 1,024 |
| Accounts payable and other *(Note 17)* | **10,063** | 9,863 |
| Accounts payable to affiliates | **21** | 40 |
| Interest payable | **624** | 669 |
| Current portion of long-term debt *(Note 18)* | **4,404** | 3,259 |
| | **16,010** | 14,855 |
| Long-term debt *(Note 18)* | **59,661** | 60,327 |
| Other long-term liabilities | **8,324** | 8,834 |
| Deferred income taxes *(Note 25)* | **9,867** | 9,454 |
| | **93,862** | 93,470 |
| Commitments and contingencies *(Note 30)* | | |
| Equity | | |
| Share capital *(Note 21)* | | |
| Preference shares | **7,747** | 7,747 |
| Common shares *(2,025 and 2,022 outstanding at December 31, 2019 and December 31, 2018, respectively)* | **64,746** | 64,677 |
| Additional paid-in capital | **187** | — |
| Deficit | **(6,314)** | (5,538) |
| Accumulated other comprehensive income/(loss) *(Note 23)* | **(272)** | 2,672 |
| Reciprocal shareholding | **(51)** | (88) |
| Total Enbridge Inc. shareholders' equity | **66,043** | 69,470 |
| Noncontrolling interests *(Note 20)* | **3,364** | 3,965 |
| | **69,407** | 73,435 |
| Total liabilities and equity | **163,269** | 166,905 |

Variable Interest Entities (VIEs) (*Note 12*).
The accompanying notes are an integral part of these consolidated financial statements.

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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# 1. BUSINESS OVERVIEW

The terms “we,” “our,” “us” and “Enbridge” as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution and Storage; Renewable Power Generation; and Energy Services. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

**LIQUIDS PIPELINES**
Liquids Pipelines consists of pipelines and related terminals in Canada and the United States that transport various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, Southern Lights Pipeline, Express-Platte System, Bakken System, and Feeder Pipelines and Other.

**GAS TRANSMISSION AND MIDSTREAM**
Gas Transmission and Midstream consists of investments in natural gas pipelines and gathering and processing facilities in Canada and the United States, including US Gas Transmission, Canadian Gas Transmission, US Midstream and Other.

**GAS DISTRIBUTION AND STORAGE**
Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas, which serves residential, commercial and industrial customers, located throughout Ontario. Gas Distribution and Storage also includes natural gas distribution activities in Quebec and an investment in Noverco, which holds a majority interest in a subsidiary entity engaged in distribution and energy transportation primarily in Quebec.

**RENEWABLE POWER GENERATION**
Renewable Power Generation consists primarily of investments in wind and solar power generating assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario, and Quebec and in the states of Colorado, Texas, Indiana and West Virginia. We also have offshore wind assets in operation and under development located in United Kingdom, Germany, and France.

**ENERGY SERVICES**
The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems. Energy Services also provides energy marketing services to North American refiners, producers and other customers.

**ELIMINATIONS AND OTHER**
In addition to the segments noted above, Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements, which are not allocated to business segments. Eliminations and Other also includes new business development activities and corporate investments.

**SPONSORED VEHICLES BUY-IN**

In the fourth quarter of 2018, Enbridge completed the buy-ins of our sponsored vehicles: SEP, EEP, Enbridge Energy Management, L.L.C. (EEM) and ENF, (referred to herein collectively as the Sponsored Vehicles) in a series of combination transactions, through which we acquired all of the outstanding equity securities of the Sponsored Vehicles not beneficially owned by us (collectively, the Sponsored Vehicles buy-in). Please refer to *Note 20 - Noncontrolling Interests* for further discussion of the transactions.

**ACQUISITION OF SPECTRA ENERGY CORP**

On February 27, 2017, Enbridge and Spectra Energy Corp (Spectra Energy) combined in a stock-for-stock merger transaction for a purchase price of $37.5 billion. Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge common stock for each share of Spectra Energy common stock that they owned, resulting in us acquiring 100% ownership of Spectra Energy. Please refer to *Note 8 - Acquisitions and Dispositions* for further discussion of the transaction.

**DISPOSITIONS**

During the years ended December 31, 2019 and 2018, we have disposed of a number of our non-core assets. Please refer to *Note 8 - Acquisitions and Dispositions* for further discussion of these transactions.

## 2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with U.S. Generally accepted accounting principles in the United States of America (U.S. GAAP) . Amounts are stated in Canadian dollars unless otherwise noted. As a SEC registrant, we are permitted to use U.S. GAAP for purposes of meeting both our Canadian and United States continuous disclosure requirements.

**BASIS OF PRESENTATION AND USE OF ESTIMATES**

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of ARO *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 26)*; commitments and contingencies *(Note 30)*; and estimates of losses related to environmental remediation obligations *(Note 30)*. Actual results could differ from these estimates.

**PRINCIPLES OF CONSOLIDATION**

The consolidated financial statements include our accounts and accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE entity that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis, if there are changes in the facts and circumstances related to a VIE. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

**REGULATION**

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the CER, the FERC, the Alberta Energy Regulator, the OEB and La Régie de l'Energie du Québec. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's LMCI. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 7)*.

**REVENUE RECOGNITION**

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from liquids and gas pipeline businesses are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts rateably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require Enbridge to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay Enbridge a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received. For the years ended December 31, 2019, 2018 and 2017, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $169 million, $208 million, and $196 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise area. Since July 1, 2011, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the CTS, under which revenues are recorded when services are performed. Effective on that date, we prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by specific rate orders.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded gross because the related contracts are not held for trading purposes and we are acting as the principal in the transactions. For our energy marketing contracts, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

**DERIVATIVE INSTRUMENTS AND HEDGING**

**Non-qualifying Derivatives**

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

**Derivatives in Qualifying Hedging Relationships**

We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires Enbridge to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

**Cash Flow Hedges**

We use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. The change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

**Fair Value Hedges**

We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

**Net Investment Hedges**

Gains and losses arising from translation of net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We designate foreign currency derivatives and United States dollar denominated debt as hedges of net investments in United States dollar denominated foreign operations. As a result, the change in the fair value of the foreign currency derivatives as well as the translation of United States dollar denominated debt are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from disposal of a foreign operation.

**Classification of Derivatives**
We recognize the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

**Balance Sheet Offset**
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

**Transaction Costs**
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a deduction from Long-term debt on the Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

**EQUITY INVESTMENTS**
Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

**RESTRICTED LONG-TERM INVESTMENTS**
Long-term investments that are restricted as to withdrawal or usage, for the purposes of the CER's LMCI, are presented as Restricted long-term investments on the Consolidated Statements of Financial Position.

**OTHER INVESTMENTS**
Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured at fair value measurement alternative and recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for impairment each reporting period. Equity investments with readily determinable fair values are measured at fair value through net income. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified either as available for sale securities measured at fair value through OCI or as held to maturity securities measured at amortized cost.

**NONCONTROLLING INTERESTS**
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

**INCOME TAXES**
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in income taxes.

**FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION**
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

**CASH AND CASH EQUIVALENTS**
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

**RESTRICTED CASH**
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

**LOANS AND RECEIVABLES**
Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

**ALLOWANCE FOR DOUBTFUL ACCOUNTS**
Allowance for doubtful accounts is determined based on collection history. When we have determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

**NATURAL GAS IMBALANCES**
The Consolidated Statements of Financial Position include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

**INVENTORY**
Inventory is comprised of natural gas in storage held in Enbridge Gas, and crude oil and natural gas held primarily by energy services businesses in the Energy Services segment. Natural gas in storage in Enbridge Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs on the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

**PROPERTY, PLANT AND EQUIPMENT**
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

**DEFERRED AMOUNTS AND OTHER ASSETS**
Deferred amounts and other assets primarily include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including: deferred income taxes; contractual receivables under the terms of long-term delivery contracts; derivative financial instruments; and actuarial gains and losses arising from defined benefit pension plans.

**INTANGIBLE ASSETS**
Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. From January 1, 2017 through July 3, 2018, emission allowances, which are recorded at their original cost, were purchased in order to meet GHG compliance obligations. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

**GOODWILL**
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than it's carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

The allocation of goodwill to held for sale and disposed businesses is based on the relative fair value of businesses included in the particular reporting unit.

**IMPAIRMENT**

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt securities and equity investments, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs and determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, we assess the assets for impairment when there is no longer reasonable assurance of timely collection. If evidence of impairment is noted, we reduce the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

**ASSET RETIREMENT OBLIGATIONS**

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

**PENSION AND OTHER POSTRETIREMENT BENEFITS**

We sponsor defined benefit and defined contribution pension plans, and defined benefit OPEB plans, which provide group health care, life insurance benefits and other postretirement benefits.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Society of Actuaries in the United States (revised in 2019) and the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligations of our United States pension plan (the United States Plan) and our Canadian pension plans (the Canadian Plans), respectively.

We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension and OPEB plan assets are measured at fair value. The expected return on funded pension and OPEB plan assets is determined using market related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (funded pension and OPEB plans) or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in our Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in our Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to Earnings and includes:

- Cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- Interest cost of plan obligations;
- Expected return on plan assets (funded pension and OPEB plans);
- Amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our non-utility operations and from defined benefit OPEB plans are presented as a component of AOCI in our Consolidated Statements of Changes in Equity. Any unrecognized actuarial gains and losses and prior service costs and credits related to those plans that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our utility operations, which have been permitted or are expected to be permitted by the Regulators, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in our Consolidated Statements of Financial Position.

Our utility operations also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to Earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

**STOCK-BASED COMPENSATION**

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge’s shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSUs are also dependent on our performance relative to performance targets set out under the plan.

**COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES**

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

## 3. CHANGES IN ACCOUNTING POLICIES

**CHANGES IN ACCOUNTING POLICIES**

There were no changes in accounting policies during the year ended December 31, 2019.

**ADOPTION OF NEW ACCOUNTING STANDARDS**

**Cloud Computing Arrangements**

Effective January 1, 2019, we adopted Accounting Standards Update (ASU) 2018-15 on a prospective basis. The new standard was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. This ASU specifies that an entity would apply ASC 350-40, Internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. The amendments in the update also require that the capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service, in addition to specifying that the capitalized costs must be presented on the same balance sheet line as the prepayment of fees related to the hosting arrangement. This ASU requires similar consistency in classifications from a cash flow statement perspective. The adoption of this ASU did not have a material impact on our consolidated financial statements.

**Improvements to Accounting for Hedging Activities**

Effective January 1, 2019, we adopted ASU 2017-12 on a modified retrospective basis. The new standard was issued with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The amendments allow cash flow hedging of contractually specified components in financial and non-financial items. As a result of the new standard, hedge ineffectiveness will no longer be measured or recorded, and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

**Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium**
Effective January 1, 2019, we adopted ASU 2017-08 on a modified retrospective basis. The new standard was issued with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

**Recognition of Leases**
Effective January 1, 2019 we adopted ASU 2016-02 Leases (Topic 842) using the modified retrospective approach.

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities on the statement of financial position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets, as described under the Impairment section of the Significant Accounting Policies Note 2 in the annual consolidated financial statements.

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

In adopting Topic 842, we elected the package of practical expedients permitted under the transition guidance. The election to apply the package of practical expedients allows an entity to not apply the new lease standard to the prior year comparative periods in the year of adoption. The application of the package of practical expedients also permits entities not to reassess whether any expired or existing contracts contain leases in accordance with the new guidance, lease classifications, and whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements on existing agreements that had commenced prior to January 1, 2019.

On January 1, 2019, ROU assets and corresponding lease liabilities of $771 million were recorded in connection with the adoption of Topic 842. When added to the $85 million of pre-existing liabilities relating to operating leases for which we no longer utilize the leased assets, total lease liabilities at January 1, 2019 were $856 million. All lease liabilities were measured using a weighted average discount rate of 4.32%. The adoption of this standard had no impact to the Consolidated Statements of Earnings, Comprehensive Income, Changes in Equity or Cash Flows during the period.

**Improvements to Related Party Guidance for Variable Interest Entities**
Effective September 30, 2019, we adopted ASU 2018-17 on a retrospective basis. The new standard was issued with the objective to improve the related party guidance on determining whether fees paid to decision makers and service providers (decision maker fees) are variable interests. Under the new guidance, reporting entities must consider indirect interests held through related parties in common control arrangements on a proportionate basis, rather than as the equivalent of a direct interest in its entirety, when determining if decision maker fees constitute a variable interest. The adoption of this ASU did not have a material impact on our consolidated financial statements.

**FUTURE ACCOUNTING POLICY CHANGES**

**Accounting for Income Taxes**

ASU 2019-12 was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 as well as provides simplification by clarifying and amending existing guidance. ASU 2019-12 is effective January 1, 2021 and entities are permitted to adopt the standard early. We are currently assessing the impact of the new standard on our consolidated financial statements.

**Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers**

ASU 2018-18 was issued in November 2018 to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update is effective January 1, 2020 and early adoption is permitted. The adoption of ASU 2018-18 is not expected to have a material impact on our consolidated financial statements.

**Disclosure Effectiveness**

In August 2018, the Financial Accounting Standards Board issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2018-14 is not expected to have a material impact on our consolidated financial statements.

ASU 2018-13 was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. The adoption of ASU 2018-13 is not expected to have a material impact on our consolidated financial statements.

**Accounting for Credit Losses**

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delay the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity will recognize as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses. Both accounting updates are effective January 1, 2020.

We have performed a detailed evaluation as of December 31, 2019 and do not anticipate the adoption of ASU 2016-13 to have a material impact on our consolidated financial statements.

# 4. REVENUE

## REVENUE FROM CONTRACTS WITH CUSTOMERS
### Major Products and Services

| Year ended December 31, 2019 | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Transportation revenue | **9,082** | **4,477** | **743** | **—** | **—** | **—** | **14,302** |
| Storage and other revenue | **109** | **268** | **201** | **—** | **—** | **—** | **578** |
| Gas gathering and processing revenue | **—** | **423** | **—** | **—** | **—** | **—** | **423** |
| Gas distribution revenue | **—** | **—** | **4,210** | **—** | **—** | **—** | **4,210** |
| Electricity and transmission revenue | **—** | **—** | **—** | **180** | **—** | **—** | **180** |
| Commodity sales | **—** | **4** | **—** | **—** | **—** | **—** | **4** |
| Total revenue from contracts with customers | **9,191** | **5,172** | **5,154** | **180** | **—** | **—** | **19,697** |
| Commodity sales | **—** | **—** | **—** | **—** | **29,305** | **—** | **29,305** |
| Other revenue[1,2] | **659** | **30** | **9** | **387** | **(2)** | **(16)** | **1,067** |
| Intersegment revenue | **369** | **5** | **16** | **—** | **71** | **(461)** | **—** |
| Total revenue | **10,219** | **5,207** | **5,179** | **567** | **29,374** | **(477)** | **50,069** |

| Year ended December 31, 2018 | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Transportation revenue | 8,488 | 3,928 | 875 | — | — | — | 13,291 |
| Storage and other revenue | 101 | 222 | 196 | — | — | — | 519 |
| Gas gathering and processing revenue | — | 815 | — | — | — | — | 815 |
| Gas distribution revenue | — | — | 4,376 | — | — | — | 4,376 |
| Electricity and transmission revenue | — | — | — | 206 | — | — | 206 |
| Commodity sales | — | 1,590 | — | — | — | — | 1,590 |
| Total revenue from contracts with customers | 8,589 | 6,555 | 5,447 | 206 | — | — | 20,797 |
| Commodity sales | — | — | — | — | 26,070 | — | 26,070 |
| Other revenue[1,2] | (894) | 6 | 9 | 361 | 4 | 25 | (489) |
| Intersegment revenue | 384 | 10 | 14 | — | 154 | (562) | — |
| Total revenue | 8,079 | 6,571 | 5,470 | 567 | 26,228 | (537) | 46,378 |

*1 Includes mark-to-market gains/(losses) from our hedging program.*
*2 Includes revenues from lease contracts. Refer to Note 27 Leases.*

We disaggregate revenue into categories which represent our principal performance obligations within each business segment because these revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

**Contract Balances**

| | Contract Receivables | Contract Assets | Contract Liabilities |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Balance as at December 31, 2018 | 1,929 | 191 | 1,297 |
| Balance as at December 31, 2019 | **2,099** | **216** | **1,424** |

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2019 included in contract liabilities at the beginning of the period is $185 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2019 were $358 million. Revenue recognized during the year ended December 31, 2018 included in contract liabilities at the beginning of the period is $183 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2018 were $449 million.

**Performance Obligations**

| Segment | Nature of Performance Obligation |
|---|---|
| Liquids Pipelines | • Transportation and storage of crude oil and NGLs |
| Gas Transmission and Midstream | • Transportation, storage, gathering, compression and treating of natural gas<br>• Transportation of NGLs<br>• Sale of crude oil, natural gas and NGLs |
| Gas Distribution and Storage | • Supply and delivery of natural gas<br>• Transportation of natural gas<br>• Storage of natural gas |
| Renewable Power Generation | • Generation and transmission of electricity<br>• Delivery of electricity from renewable energy generation facilities |

There was no material revenue recognized in the year ended December 31, 2019 from performance obligations satisfied in previous periods.

**Payment Terms**

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution and Storage customers are received on a continuous basis based on established billing cycles.

Certain contracts in the United States offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period which is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs is recorded as a contract liability. The FMPs are not considered to be a financing arrangement because the payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

**Revenue to be Recognized from Unfulfilled Performance Obligations**

Total revenue from performance obligations expected to be fulfilled in future periods is $65.8 billion, of which $7.1 billion is expected to be recognized during the year ended December 31, 2020.

The revenues excluded from the amounts above based on optional exemptions available under ASC 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts of revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

**SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE**

**Long-Term Transportation Agreements**

For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

**Estimates of Variable Consideration**

Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

**Recognition and Measurement of Revenue**

| **Year ended December 31, 2019** | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenue from products transferred at a point in time | **—** | **4** | **65** | **—** | **—** | **69** |
| Revenue from products and services transferred over time[1] | **9,191** | **5,168** | **5,089** | **180** | **—** | **19,628** |
| Total revenue from contracts with customers | **9,191** | **5,172** | **5,154** | **180** | **—** | **19,697** |

*1 Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.*

| Year ended December 31, 2018 | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenue from products transferred at a point in time[1] | — | 1,590 | 68 | — | — | 1,658 |
| Revenue from products and services transferred over time[2] | 8,589 | 4,965 | 5,379 | 206 | — | 19,139 |
| Total revenue from contracts with customers | 8,589 | 6,555 | 5,447 | 206 | — | 20,797 |

*1 Revenue from sales of crude oil, natural gas and NGLs. Revenue from commodity sales where the commodity sold is not immediately consumed prior to use is recognized at the point in time when the contractually specified volume of the commodity has been delivered.*

*2 Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.*

**Performance Obligations Satisfied Over Time**

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

**Determination of Transaction Prices**

Prices for gas processing and transportation services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

# 5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2019, 2018 and 2017 is as follows:

| **Year ended December 31, 2019** | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Revenues | **10,219** | **5,207** | **5,179** | **567** | **29,374** | **(477)** | **50,069** |
| Commodity and gas distribution costs | **(29)** | **—** | **(2,354)** | **(2)** | **(29,091)** | **472** | **(31,004)** |
| Operating and administrative | **(3,298)** | **(2,232)** | **(1,149)** | **(189)** | **(44)** | **(79)** | **(6,991)** |
| Impairment of long-lived assets | **(21)** | **(105)** | **—** | **(297)** | **—** | **—** | **(423)** |
| Income/(loss) from equity investments | **780** | **682** | **4** | **31** | **8** | **(2)** | **1,503** |
| Other income/(expense) | **30** | **(181)** | **67** | **1** | **3** | **515** | **435** |
| Earnings before interest, income tax expense, and depreciation and amortization | **7,681** | **3,371** | **1,747** | **111** | **250** | **429** | **13,589** |
| Depreciation and amortization | | | | | | | **(3,391)** |
| Interest expense | | | | | | | **(2,663)** |
| Income tax expense | | | | | | | **(1,708)** |
| Earnings | | | | | | | **5,827** |
| Capital expenditures[1] | **2,548** | **1,753** | **1,100** | **23** | **2** | **124** | **5,550** |
| Total property, plant and equipment, net | **48,783** | **25,268** | **15,622** | **3,658** | **24** | **368** | **93,723** |

| Year ended December 31, 2018 | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Revenues | 8,079 | 6,571 | 5,470 | 567 | 26,228 | (537) | 46,378 |
| Commodity and gas distribution costs | (16) | (1,481) | (2,748) | (7) | (25,689) | 540 | (29,401) |
| Operating and administrative | (3,124) | (2,102) | (1,111) | (157) | (73) | (225) | (6,792) |
| Impairment of long-lived assets | (180) | (914) | — | (4) | — | (6) | (1,104) |
| Impairment of goodwill | — | (1,019) | — | — | — | — | (1,019) |
| Income/(loss) from equity investments | 577 | 930 | 11 | (28) | 18 | 1 | 1,509 |
| Other income/(expense) | (5) | 349 | 89 | (2) | (2) | (481) | (52) |
| Earnings/(loss) before interest, income tax expense, and depreciation and amortization | 5,331 | 2,334 | 1,711 | 369 | 482 | (708) | 9,519 |
| Depreciation and amortization | | | | | | | (3,246) |
| Interest expense | | | | | | | (2,703) |
| Income tax expense | | | | | | | (237) |
| Earnings | | | | | | | 3,333 |
| Capital expenditures[1] | 3,102 | 2,644 | 1,066 | 33 | — | 27 | 6,872 |
| Total property, plant and equipment, net | 49,214 | 25,601 | 15,148 | 4,335 | 22 | 220 | 94,540 |

| Year ended December 31, 2017 | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Revenues | 8,913 | 7,067 | 4,992 | 534 | 23,282 | (410) | 44,378 |
| Commodity and gas distribution costs | (18) | (2,834) | (2,689) | — | (23,508) | 412 | (28,637) |
| Operating and administrative | (2,949) | (1,756) | (960) | (163) | (47) | (567) | (6,442) |
| Impairment of long-lived assets | — | (4,463) | — | — | — | — | (4,463) |
| Impairment of goodwill | — | (102) | — | — | — | — | (102) |
| Income/(loss) from equity investments | 416 | 653 | 23 | 6 | 8 | (4) | 1,102 |
| Other income/(expense) | 33 | 166 | 24 | (5) | 2 | 232 | 452 |
| Earnings/(loss) before interest, income tax expense, and depreciation and amortization | 6,395 | (1,269) | 1,390 | 372 | (263) | (337) | 6,288 |
| Depreciation and amortization | | | | | | | (3,163) |
| Interest expense | | | | | | | (2,556) |
| Income tax recovery | | | | | | | 2,697 |
| Earnings | | | | | | | 3,266 |
| Capital expenditures[1] | 2,799 | 4,016 | 1,177 | 321 | 1 | 108 | 8,422 |

*1 Includes allowance for equity funds used during construction.*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

No non-affiliated customer exceeds 10% of our third-party revenues for the years ended December 31, 2019 and 2018, respectively. Our largest non-affiliated customer accounted for approximately 11.8% of our third-party revenues for the year ended December 31, 2017. Revenue from this one customer is primarily reported in the Energy Services segment.

**GEOGRAPHIC INFORMATION**

**Revenues**[1]

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Canada | **19,954** | 19,023 | 18,076 |
| United States | **30,115** | 27,355 | 26,302 |
| | **50,069** | 46,378 | 44,378 |

*1 Revenues are based on the country of origin of the product or service sold.*

**Property, Plant and Equipment**[1]

| December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canada | **45,993** | 44,716 |
| United States | **47,730** | 49,824 |
| | **93,723** | 94,540 |

*1 Amounts are based on the location where the assets are held.*

# 6. EARNINGS PER COMMON SHARE

**BASIC**

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of approximately 6 million as at December 31, 2019, 12 million as at December 31, 2018, and 13 million as at December 31, 2017, resulting from our reciprocal investment in Noverco.

**DILUTED**

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

| December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(number of shares in millions)* | | | |
| Weighted average shares outstanding | **2,017** | 1,724 | 1,525 |
| Effect of dilutive options | **3** | 3 | 7 |
| Diluted weighted average shares outstanding | **2,020** | 1,727 | 1,532 |

For the years ended December 31, 2019, 2018 and 2017, 17.8 million, 26.8 million and 14.3 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $53.56, $50.38 and $56.71, respectively, were excluded from the diluted earnings per common share calculation.

# 7. REGULATORY MATTERS

**GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS**

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion.

A number of our businesses are subject to regulation by various regulators, including the CER, OEB and FERC. We also collect and set aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI *(Note 14)* and to cover future removal and site restoration reserves as approved by the OEB and other agencies. Amounts expected to be paid for these future costs are recognized as long-term regulatory liabilities. Our significant regulated businesses and the related accounting impacts, are described below.

**Liquids Pipelines**

**Canadian Mainline**

Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the CER. Tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a CLT for all volumes shipped on the Canadian Mainline and an IJT for all volumes shipped from western Canadian receipt points to delivery points on Enbridge's Lakehead System, as well as delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with CER guidelines, was approved by the CER in June 2011, and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

**Southern Lights Pipeline**

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline is regulated by the CER. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity of 10%.

## Gas Transmission and Midstream

**BC Pipeline and BC Field Services**

Until December 31, 2019, our Gas Transmission and Midstream business in British Columbia was comprised of BC Pipeline and BC Field Services. BC Pipeline and BC Field Services provide fee-for-service based natural gas transmission and raw gas gathering and processing services, respectively.

BC Pipeline is regulated by the CER under full cost-of-service regulation. Under the current CER-authorized rate structure for our BC Pipeline, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of the temporary differences that created the deferred income taxes, it is expected that tolls will be adjusted to recover these taxes. Since most existing temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the BC Pipeline assets.

On December 31, 2019, we closed the sale of our BC Field Services business to Brookfield Infrastructure Partners L.P. and its institutional partners (Brookfield) *(Note 8)*. The BC Field Services business was regulated by the CER under the Framework for Light-Handed Regulation. Regulatory assets of $349 million, related to the regulatory offset to deferred income tax liabilities associated with the BC Field Services business, were derecognized as a result of this sale.

**Spectra Energy Partners, LP**

Most of SEP's gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. Rates for the FERC jurisdictional services are governed by the applicable FERC-approved natural gas tariffs while rates for the intrastate and/or gathering services are governed by the appropriate state gas commissions.

## Gas Distribution and Storage

**Enbridge Gas Inc.**

Enbridge Gas' distribution rates, beginning in 2019, are set under a five-year IR framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers, any earnings in excess of 150 basis points over the annual OEB approved return on equity.

**FINANCIAL STATEMENT EFFECTS**

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities on the Consolidated Statements of Financial Position:

| December 31, | Recovery/Refund Period Ends | **2019** | 2018 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Regulatory assets/(liabilities), net** | | | |
| Liquids Pipelines | | | |
| Deferred income taxes[1] | Various | **1,767** | 1,673 |
| Tolling deferrals | Various | **(25)** | (28) |
| Recoverable income taxes | Through 2040 | **24** | 27 |
| Pipeline future abandonment costs[2] | Various | **(293)** | (201) |
| Other deferrals | Various | **32** | — |
| Gas Transmission and Midstream | | | |
| Deferred income taxes[1] | Various | **511** | 826 |
| Regulatory liability related to income taxes[3] | Various | **(866)** | (912) |
| Long-term debt[4] | Various | **108** | 124 |
| Pipeline future abandonment costs[2] | Various | **(159)** | (111) |
| Other | Various | **215** | 205 |
| Gas Distribution and Storage | | | |
| Deferred income taxes[1] | Various | **1,273** | 1,132 |
| Purchased gas variance | 2020 | **(19)** | 197 |
| Pension plans and OPEB | Various | **275** | 118 |
| Future removal and site restoration reserves[5] | Various | **(1,424)** | (1,107) |
| Federal carbon program | 2020 | **145** | — |
| Long-term debt[4] | Various | **362** | 387 |
| Constant dollar net salvage adjustment | 2018 | **—** | 6 |
| Other | Various | **88** | (4) |

*1 The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.*

*2 The pipeline future abandonment costs liability results from amounts collected and set aside in accordance with the CER's LMCI to cover future abandonment costs for CER regulated Canadian pipelines. Funds collected are included in Restricted long-term investments (Note 14).Concurrently, we reflect the future abandonment cost as a regulatory liability. The settlement of this balance will occur as pipeline abandonment costs are incurred.*

*3 Relates to the establishment of a regulatory liability as a result of the United States tax reform legislation enacted December 22, 2017.*

*4 The debt balance represents our regulatory offset to the fair value adjustment to debt that resulted from the merger with Spectra Energy. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

*5 Future removal and site restoration reserves result from amounts collected from customers by us, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that we have collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate-regulated accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

**OTHER ITEMS AFFECTED BY RATE REGULATION**

**Allowance for Funds Used During Construction and Other Capitalized Costs**

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

**Operating Cost Capitalization**
With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

## 8. ACQUISITIONS AND DISPOSITIONS

**ACQUISITIONS**
**Spectra Energy Corp**
On February 27, 2017, Enbridge and Spectra Energy combined in the Merger Transaction for a purchase price of $37.5 billion. Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge common stock for each share of Spectra Energy common stock that they owned, giving us 100% ownership of Spectra Energy.

Consideration offered to complete the Merger Transaction included 691 million common shares of Enbridge at US$41.34 per share, based on the February 24, 2017 closing price on the NYSE, for a total value of $37,429 million in common shares issued to Spectra Energy shareholders, plus approximately $3 million in cash in lieu of any fractional shares, and 3.5 million share options with a fair value of $77 million, that were exchanged for Spectra Energy's outstanding stock compensation awards.

Spectra Energy, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America's leading natural gas infrastructure companies. Spectra Energy also owns and operates a crude oil pipeline system that connects Canadian and United States producers to refineries in the United States Rocky Mountain and Midwest regions. The Merger Transaction brought together two highly complementary platforms to create North America's largest energy infrastructure company and meaningfully enhanced customer optionality, positioning us for long-term growth opportunities, and strengthening our balance sheet.

The Merger Transaction was accounted for as a business combination under the acquisition method of accounting as prescribed by Accounting Standards Codification (ASC) 805 *Business Combinations*. The acquired tangible and intangible assets and assumed liabilities were recorded at their estimated fair values at the date of acquisition.

The purchase price allocation was completed as at December 31, 2017, along with the allocation of goodwill to reporting units *(Note 16)*. Our reporting units are equivalent to our identified segments with the exception of the previous Gas Transmission and Midstream segment, which was composed of two reporting units: gas transmission and gas midstream.

The following table summarizes the estimated fair values that were assigned to the net assets of Spectra Energy:

| February 27, 2017 *(millions of Canadian dollars)* | |
|---|---|
| Fair value of net assets acquired: | |
| Current assets (a) | 2,432 |
| Property, plant and equipment, net (b) | 33,555 |
| Restricted long-term investments | 144 |
| Long-term investments (c) | 5,000 |
| Deferred amounts and other assets (d) | 2,390 |
| Intangible assets, net (e) | 1,288 |
| Current liabilities (a) | (3,982) |
| Long-term debt (d) | (21,444) |
| Other long-term liabilities | (1,983) |
| Deferred income taxes (b) | (7,670) |
| Noncontrolling interests (f) | (8,877) |
| | 853 |
| Goodwill (g) | 36,656 |
| | 37,509 |
| Purchase price: | |
| Common shares | 37,429 |
| Cash | 3 |
| Fair value of outstanding earned stock compensation awards recorded in Additional paid-in capital | 77 |
| | 37,509 |

a) Accounts receivable is comprised primarily of customer trade receivables and natural gas imbalances. As such, the fair value of accounts receivable approximates the net carrying value of $1,174 million. The gross amount due of $1,190 million, of which $16 million is not expected to be collected, is included in current assets.

During the fourth quarter of 2017, we identified certain transactions that were not reflected in the purchase price equation. This resulted in a $67 million and $548 million increase in current assets and current liabilities, respectively, and a $481 million decrease in long-term debt.

b) We have applied the valuation methodologies described in ASC 820 *Fair Value Measurements and Disclosures*, to value the property, plant and equipment purchased. The fair value of Spectra Energy's rate-regulated property, plant and equipment was determined using a market participant perspective, which is their carrying amount. The fair value of the remaining non-regulated property, plant and equipment was determined primarily using variations of the income approach, which is based on the present value of the future after-tax cash flows attributable to each non-regulated asset. Some of the more significant assumptions inherent in the development of the values, from the perspective of a market participant, include, but are not limited to, the amount and timing of projected future cash flows (including revenue and profitability); the discount rate selected to measure the risks inherent in the future cash flows; the assessment of the asset's life cycle; the competitive trends impacting the asset; and customer turnover.

During the third quarter of 2017, Spectra Energy's right-of-way agreements were reclassified from intangible assets to property, plant and equipment to conform the presentation of these agreements with our accounting policy pertaining to rights-of-way. The purchase price allocation above reflects this reclassification, which amounted to $830 million as at February 27, 2017. There is no change in the amortization period for the right-of-way agreements as a result of this reclassification.

During the fourth quarter of 2017, we finalized our fair value measurement of the BC Pipeline & Field Services businesses, which resulted in decreases to property, plant and equipment of $1,955 million and deferred income tax liabilities of $661 million as at February 27, 2017.

c) Long-term investments represent Spectra Energy's 50% equity investment in DCP Midstream, Gulfstream Natural Gas System, L.L.C., NEXUS Gas Transmission, LLC (NEXUS), Steckman Ridge LP, Islander East Pipeline Company, L.L.C., Southeast Supply Header L.L.C., and 20% equity interest in PennEast Pipeline Company LLC (PennEast). The fair value of these investments was determined using an income approach.

d) Fair value of long-term debt was determined based on the current underlying Government of Canada and United States Treasury interest rates on the corresponding bonds, as well as an implied credit spread based on current market conditions and resulted in an increase in the book value of debt of $1.5 billion. The fair value adjustment to long-term debt related to rate-regulated entities of $629 million also results in a regulatory offset in Deferred amounts and other assets in the Consolidated Statements of Financial Position.

During the fourth quarter of 2017, deferred amounts and other assets decreased by $530 million as at February 27, 2017 due to the finalization of BC Pipelines & Field Services' fair value measurement, as discussed under *(b)* above.

During the fourth quarter of 2017, we identified certain transactions that were not reflected in the purchase price equation. This resulted in a $481 million decrease in long-term debt, as discussed under *(a)* above.

e) Intangible assets primarily consist of customer relationships in the non-regulated business, which represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition, determined using the income approach. Intangible assets are amortized on a straight-line basis over their expected lives.

During the third quarter of 2017, intangible assets decreased by $830 million as at February 27, 2017 due to a reclassification to property, plant and equipment, as discussed under *(b)* above.

The fair value of intangible assets acquired through the Merger Transaction, by major classes is as follows:

| As at February 27, 2017 | Weighted Average Amortization Rate | Fair Value |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Customer relationships[1] | 3.7% | 739 |
| Project agreement[2] | 4.0% | 105 |
| Software | 11.1% | 329 |
| Other | 4.2% | 115 |
| | | 1,288 |

*1 Represents customer relationships in the non-regulated business, which were capitalized upon acquisition.*

*2 Represents a project agreement between SEP, NextEra Energy, Inc., Duke Energy Corporation (Duke Energy) and Williams Partners L.P. In accordance with the agreement, payments will be made, based on our proportional ownership interest in Sabal Trail, as certain milestones of the project are met. Amortization of the intangible asset began on July 3, 2017, when Sabal Trail was placed into service (Note 13).*

f) The fair value of Spectra Energy's noncontrolling interests includes approximately 78.4 million SEP common units outstanding to the public, valued at the February 24, 2017 closing price of US $44.88 per common unit on the NYSE, and units held by third parties in Maritimes & Northeast Pipeline, L.L.C., Sabal Trail and Algonquin Gas Transmission, L.L.C., valued based on the underlying net assets of each reporting unit and preferred stock held by third parties in Union Gas and Westcoast Energy Inc.

During the third quarter of 2017, we finalized our fair value measurement of Sabal Trail, which resulted in an increase to noncontrolling interests of $85 million as at February 27, 2017.

g) We recorded $36.7 billion in goodwill, which is primarily related to expected synergies from the Merger Transaction. The goodwill balance recognized is not deductible for tax purposes. Factors that contributed to the goodwill include the opportunity to expand our natural gas pipelines segment, the potential for cost and supply chain optimization synergies, existing assembled assets and work force that cannot be duplicated at the same cost by a new entrant, franchise rights and other intangibles not separately identifiable because they are inextricably linked to the provision of regulated utility service and the enhanced scale and geographic diversity which provide greater optionality and platforms for future growth.

During the third quarter of 2017, goodwill increased by $85 million as at February 27, 2017 due to the finalization of the fair value measurement of Sabal Trail as discussed under *(f)* above.

During the fourth quarter of 2017, goodwill increased by $1,824 million as at February 27, 2017 due to the finalization of the fair value measurement of BC Pipelines & Field Services as discussed under *(b)* above.

Acquisition-related expenses incurred were approximately $231 million. Costs incurred for the year ended December 31, 2017 of $180 million were included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Merger Transaction, we began consolidating Spectra Energy. Since the closing date of February 27, 2017 through December 31, 2017, Spectra Energy has generated approximately $5,740 million in revenues and $2,574 million in earnings.

Our supplemental pro forma consolidated financial information for the year ended December 31, 2017, including the results of operations for Spectra Energy as if the Merger Transaction had been completed on January 1, 2017 are as follows:

| Year ended December 31, | **2017** |
|---|---|
| *(unaudited; millions of Canadian dollars)* | |
| Revenues | **45,669** |
| Earnings attributable to common shareholders[1] | **2,902** |

*1 Merger Transaction costs of $180 million (after-tax $131 million) were excluded from earnings for the year ended December 31, 2017.*

**ASSETS HELD FOR SALE**

**Line 10 Crude Oil Pipeline**

In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and EEP, own the Canadian and United States portions of Line 10, respectively, and the related assets are included in our Liquids Pipeline segment. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2020.

A loss of $154 million was included within Impairment of long-lived assets on the Consolidated Statements of Earnings for the year ended December 31, 2018 in relation to measuring Line 10 assets at the lower of their carrying value or fair value less costs to sell.

**Montana-Alberta Tie Line**

In the fourth quarter of 2019, we committed to a plan to sell the Montana-Alberta Tie Line transmission assets, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta. Its related assets are included in our Renewable Power Generation segment. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

Upon the reclassification and subsequent remeasurement of MATL assets as held for sale, a loss of $297 million was included within Impairment of long-lived assets on the Consolidated Statements of Earnings.

**Summary of Assets Held for Sale**

The table below summarizes the presentation of net assets held for sale in our Consolidated Statements of Financial Position:

| | **December 31, 2019** | December 31, 2018[2] |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Accounts receivable and other (current assets held for sale) | **28** | 117 |
| Deferred amounts and other assets (long-term assets held for sale)[1] | **269** | 2,383 |
| Accounts payable and other (current liabilities held for sale) | **—** | (63) |
| Other long-term liabilities (long-term liabilities held for sale) | **—** | (96) |
| Net assets held for sale | **297** | 2,341 |

*1 Included within Deferred amounts and other assets at December 31, 2019 and 2018 respectively is property, plant and equipment of $181 million and $2.1 billion.*

*2 Figures are inclusive of net assets held for sale at December 31, 2018 and subsequently disposed of during the year ended December 31, 2019.*

**DISPOSITIONS**

**St. Lawrence Gas Company, Inc.**

In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. (St. Lawrence Gas). St. Lawrence Gas assets were included in the Gas Distribution and Storage segment. On November 1, 2019 we closed the sale of St. Lawrence Gas for cash proceeds of approximately $72 million (US$55 million). After closing adjustments, a loss on disposal of $10 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

**Enbridge Gas New Brunswick**

In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB). EGNB assets were a part of our Gas Distribution and Storage segment. On October 1, 2019 we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp. for cash proceeds of approximately $331 million. After closing adjustments, a loss on disposal of $3 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

As EGNB assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As such, allocated goodwill of $133 million was included in assets subsequently disposed.

**Canadian Natural Gas Gathering and Processing Businesses**
On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately $4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations (collectively, Canadian Natural Gas Gathering and Processing Businesses assets).

As the Canadian Natural Gas Gathering and Processing Businesses assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit of these assets using a relative fair value approach. As a result of the goodwill allocation, the carrying value of Canadian Natural Gas Gathering and Processing Businesses assets was greater than the sale price consideration less the cost to sell and we recorded a goodwill impairment of $1,019 million on the Consolidated Statements of Earnings for the year ended December 31, 2018. The held for sale classification represented a triggering event and required us to perform a goodwill impairment test for the related reporting unit. The results of the test did not indicate any additional goodwill impairment.

On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately $2.5 billion. After closing adjustments, a gain on disposal of $34 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2018.

On December 31, 2019, we closed the sale of the federally regulated facilities for proceeds of approximately $1.7 billion. After closing adjustments, a loss on disposal of $268 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019. As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As such, allocated goodwill of $55 million was included in assets subsequently disposed.

**Renewable Assets**
On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two United States renewable assets and 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets) to the CPPIB. Total cash proceeds from the transaction were $1.75 billion. In addition, CPPIB will fund their pro-rata share of the remaining capital expenditures on the Hohe See Offshore wind power project. We maintain a 51% interest in the Renewable Assets and will continue to manage, operate and provide administrative services for these assets.

A loss on disposal of $20 million (€14 million) was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2018 for the sale of 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion. Subsequent to the sale, the remaining interests in these assets continue to be accounted for as an equity method investment, and are a part of our Renewable Power Generation segment.

Gains of $62 million and $17 million (US$13 million) were included in Additional paid-in capital in the Consolidated Statements of Financial Position for the year ended December 31, 2018 for the sale of 49% interest in the Canadian and United States renewable assets, respectively.

Also, a deferred income tax recovery of $267 million ($196 million attributable to us) was recorded in the year ended December 31, 2018 as a result of the agreement entered into during the second quarter of 2018 for the Renewable Assets *(Note 25)*.

**Midcoast Operating, L.P.**
On August 1, 2018, we closed the sale of MOLP to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for total cash proceeds of $1.4 billion (US$1.1 billion). After closing adjustments recorded in the fourth quarter of 2018, a loss on disposal of $41 million (US $32 million) was included in Other income/(expense) in the Consolidated Statements of Earnings. MOLP conducted our United States natural gas and natural gas liquids gathering, processing, transportation and marketing businesses, and was a part of our Gas Transmission and Midstream segment.

Upon the reclassification and subsequent re-measurement of MOLP assets as held for sale, an asset impairment loss of $4.4 billion and a related goodwill impairment of $102 million, were included in the Consolidated Statement of Earnings for the year ended December 31, 2017.

As a result of entering into a definitive sales agreement, the fair value of the assets held for sale as at March 31, 2018 were revised based on the sale price. Accordingly, we recorded a loss of $913 million included within Impairment of long-lived assets on the Consolidated Statements of Earnings for the year ended December 31, 2018.

In the second quarter of 2018, our equity method investment in the Texas Express NGL pipeline system, also met the conditions for assets held for sale. The $447 million carrying value of Texas Express NGL pipeline system equity investment and an allocated goodwill of $262 million, were included within the disposal group as at June 30, 2018 and subsequently disposed on August 1, 2018.

Upon closing of the sale, we also recorded a liability of $387 million (US$298 million) for future volume commitments retained by us. The associated loss is included in the loss on disposal of $41 million discussed above. As at December 31, 2019 and December 31, 2018 respectively, $299 million (US$230 million) and $375 million (US$274 million) were included in liabilities on the Consolidated Statements of Financial Position.

**Sandpiper Project**
During the years ended December 31, 2018 and 2017, we sold unused pipe related to the Sandpiper for cash proceeds of approximately $38 million (US$30 million) and $148 million (US$111 million), respectively. Gains on disposal of $29 million (US$22 million) and $83 million (US$63 million) before tax were included in Operating and administrative expense in the Consolidated Statements of Earnings for the years ended December 31, 2018 and 2017, respectively. These assets were a part of our Liquids Pipelines segment.

**Olympic Pipeline**
On July 31, 2017, we completed the sale of our interest in Olympic Pipeline for cash proceeds of approximately $203 million (US$160 million). A gain on disposal of $27 million (US$21 million) before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2017. This interest was a part of our Liquids Pipelines segment.

**Ozark Pipeline**
On March 1, 2017, we completed the sale of the Ozark Pipeline assets to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$220 million), including reimbursement of costs. A gain on disposal of $14 million (US$10 million) before tax was included in Operating and administrative expense in the Consolidated Statements of Earnings for the year ended December 31, 2017. These assets were a part of our Liquids Pipelines segment.

## 9. ACCOUNTS RECEIVABLE AND OTHER

| December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Trade receivables and unbilled revenues[1] | **5,164** | 4,711 |
| Short-term portion of derivative assets | **327** | 498 |
| Other | **1,290** | 1,308 |
| | **6,781** | 6,517 |

*1 Net of allowance for doubtful accounts of $50 million and $64 million as at December 31, 2019 and 2018, respectively.*

## 10. INVENTORY

| December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Natural gas | **696** | 776 |
| Crude oil | **542** | 482 |
| Other commodities | **61** | 81 |
| | **1,299** | 1,339 |

Adjustments of $188 million, $327 million and $58 million were included in Commodity costs on the Consolidated Statements of Earnings for the years ended December 31, 2019, 2018 and 2017, respectively, to reduce inventory to market value.

## 11. PROPERTY, PLANT AND EQUIPMENT

| December 31, | Weighted Average Depreciation Rate | **2019** | 2018[1] |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Pipelines | 2.5% | **56,330** | 51,647 |
| Facilities and equipment | 2.7% | **29,287** | 27,149 |
| Land and right-of-way[2] | 2.0% | **2,947** | 2,614 |
| Gas mains, services and other | 2.7% | **12,194** | 12,088 |
| Storage | 2.3% | **2,748** | 2,730 |
| Wind turbines, solar panels and other | 4.1% | **4,914** | 5,015 |
| Other | 6.4% | **1,486** | 1,463 |
| Under construction | —% | **4,057** | 9,698 |
| Total property, plant and equipment[3] | | **113,963** | 112,404 |
| Total accumulated depreciation | | **(20,240)** | (17,864) |
| Property, plant and equipment, net | | **93,723** | 94,540 |

*1 Asset categories were revised and collapsed in the current year. 2018 comparative figures have been reclassified to conform to current year's asset classifications.*
*2 The measurement of weighted average depreciation rate excludes non-depreciable assets.*
*3 Certain assets were reclassified as held for sale as at December 31, 2019 and December 31, 2018 (Note 8).*

Depreciation expense for the years ended December 31, 2019, 2018 and 2017 was $3.0 billion, $2.9 billion and $2.9 billion, respectively.

**IMPAIRMENT**

**Access Northeast Project**

In 2019, we announced that we terminated the agreements with Eversource and National Grid related to the Access Northeast project. As a result, we recognized an impairment loss of $105 million for the year ended December 31, 2019, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings. Access Northeast is part of our Gas Transmission and Midstream segment.

Impairment charges were based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows.

## 12. VARIABLE INTEREST ENTITIES

**CONSOLIDATED VARIABLE INTEREST ENTITIES**

**Enbridge Canadian Renewable LP (ECRLP)**

ECRLP, an entity which we have a 51% ownership in, is a VIE as its limited partners lack substantive kick-out rights or participating rights. Because we have the power to direct the activities of ECRLP, we are exposed to potential losses, and we have the right to receive benefits from ECRLP, we are considered the primary beneficiary.

**Renewable Power Generation**

Through various subsidiaries, we have a majority ownership interest in Magic Valley, Wildcat, Keechi Wind Project (Keechi), New Creek and Chapman Ranch wind facilities. These wind facilities are considered VIEs due to the members' lack of substantive kick-out rights and participating rights. We are the primary beneficiary of these VIEs by virtue of our power to direct the activities that most significantly impact the economic performance of the wind facilities, and our obligation to absorb losses and the right to receive benefits that are significant.

**Enbridge Holdings (DakTex) L.L.C.**

Enbridge Holdings (DakTex) L.L.C. (DakTex) is owned 75% by a wholly-owned subsidiary of Enbridge and 25% by EEP, through which we have an effective 27.6% interest in the equity investment, Bakken Pipeline System *(Note 13)*. EEP is the primary beneficiary because it has the power to direct DakTex's activities that most significantly impact its economic performance. We consolidate EEP and by extension, also consolidate DakTex.

**Enbridge Income Partners LP (EIPLP)**

EIPLP, formed in 2002, was involved in the generation, transportation and storage of energy through interests in its Liquids Pipelines business, including the Canadian Mainline, the Regional Oil Sands System, an interest in the Alliance Pipeline, which transports natural gas, and its renewable and alternative power generation facilities. EIPLP was wound up in 2019 and thus is no longer a VIE.

**Enbridge Income Fund (the Fund)**

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. In 2019, an amendment to the Fund's governing documents was executed which resulted in the Fund no longer being considered a VIE.

**Enbridge Commercial Trust (ECT)**

In 2019, an amendment to ECT's governing documents was executed which resulted in ECT no longer being considered a VIE.

**Other Limited Partnerships**

By virtue of limited partners' lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly-owned by us and/or our subsidiaries are considered VIEs, including EEP and SEP. As these entities are 100% owned and directed by us with no third parties having the ability to direct any of the significant activities, we are considered the primary beneficiary.

The following table includes assets to be used to settle liabilities of our consolidated VIEs and liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

| December 31, | **2019**[1] | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Assets** | | |
| Cash and cash equivalents | **208** | 506 |
| Restricted cash | **1** | 61 |
| Accounts receivable and other | **76** | 2,006 |
| Accounts receivable from affiliates | **—** | 38 |
| Inventory | **4** | 244 |
| | **289** | 2,855 |
| Property, plant and equipment, net | **3,392** | 72,349 |
| Long-term investments | **15** | 6,481 |
| Restricted long-term investments | **69** | 244 |
| Deferred amounts and other assets | **4** | 3,156 |
| Intangible assets, net | **124** | 705 |
| Goodwill | **—** | 29 |
| Deferred income taxes | **—** | 131 |
| | **3,893** | 85,950 |
| **Liabilities** | | |
| Short-term borrowings | **—** | 275 |
| Accounts payable and other | **56** | 2,925 |
| Accounts payable to affiliates | **—** | 4 |
| Interest payable | **—** | 303 |
| Environmental liabilities | **—** | 22 |
| Current portion of long-term debt | **—** | 1,034 |
| | **56** | 4,563 |
| Long-term debt | **—** | 29,577 |
| Other long-term liabilities | **130** | 5,074 |
| Deferred income taxes | **5** | 6,911 |
| | **191** | 46,125 |
| Net assets before noncontrolling interests | **3,702** | 39,825 |

*1 Excludes assets and liabilities of EEP and SEP following the subsidiary guarantees agreement entered on January 22, 2019 (Note 32).*

We do not have an obligation to provide financial support to any of the consolidated VIEs.

**UNCONSOLIDATED VARIABLE INTEREST ENTITIES**

We currently hold several equity investments in limited partnerships that are assessed to be VIEs due to limited partners not having substantive kick-out rights or participating rights. We have determined that we do not have the power to direct the activities of the VIEs that most significantly impact the VIEs' economic performance. Specifically, the power to direct the activities of a majority of these VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE and none of the partners may make major decisions unilaterally.

The carrying amount of our interest in VIEs that are unconsolidated and our estimated maximum exposure to loss as at December 31, 2019 and 2018 are presented below:

| **December 31, 2019** | Carrying Amount of Investment in VIE | Enbridge's Maximum Exposure to Loss |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Aux Sable Liquid Products L.P.[1] | **267** | **331** |
| Eolien Maritime France SAS[2] | **67** | **725** |
| Enbridge Renewable Infrastructure Investments S.a.r.l.[3] | **141** | **2,720** |
| Gray Oak Holdings LLC[4] | **463** | **935** |
| PennEast Pipeline Company, LLC[5] | **106** | **368** |
| Rampion Offshore Wind Limited[6] | **600** | **620** |
| Vector Pipeline L.P.[7] | **195** | **392** |
| Other[8] | **57** | **57** |
| | **1,896** | **6,148** |

| December 31, 2018 | Carrying Amount of Investment in VIE | Enbridge's Maximum Exposure to Loss |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Aux Sable Liquid Products L.P.[1] | 311 | 375 |
| Eolien Maritime France SAS[2] | 68 | 784 |
| Enbridge Renewable Infrastructure Investments S.a.r.l.[3] | 127 | 3,037 |
| Illinois Extension Pipeline Company, L.L.C.[8] | 724 | 724 |
| NEXUS Gas Transmission, LLC[9] | 1,757 | 2,668 |
| PennEast Pipeline Company, LLC[5] | 97 | 385 |
| Rampion Offshore Wind Limited[6] | 638 | 648 |
| Vector Pipeline L.P.[7] | 198 | 301 |
| Other[8] | 27 | 27 |
| | 3,947 | 8,949 |

*1 At December 31, 2019 and 2018, the maximum exposure to loss includes a guarantee issued by us for our respective share of the VIE's borrowing on a bank credit facility.*

*2 At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $166 million and $202 million held by us as at December 31, 2019 and 2018, respectively.*

*3 At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $766 million and $461 million held by us as at December 31, 2019 and 2018, respectively.*

*4 At December 31, 2019, the maximum exposure to loss includes our portion of project construction costs.*

*5 At December 31, 2019 and 2018, the maximum exposure to loss includes the remaining expected contributions to the joint venture.*

*6 At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE.*

*7 At December 31, 2019 and 2018, the maximum exposure to loss includes the carrying value of an outstanding affiliate loan receivable for $92 million and $102 million held by us as at December 31, 2019 and 2018, respectively, in addition to us providing a credit facility for $105 million as at December 31, 2019.*

*8 At December 31, 2019 and 2018, the maximum exposure to loss is limited to our equity investment as these companies are in operation and self-sustaining.*

*9 As at December 31, 2018, the maximum exposure to loss includes the remaining expected contributions to the joint venture and parental guarantees for our portion of capacity lease agreements.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2019 and 2018.

**Gray Oak Holdings LLC**
In December 2018, Enbridge acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings LLC (Gray Oak Holdings), which operates the Gray Oak crude oil pipeline from Texas to the Gulf coast of the United States.

Gray Oak Holdings is a VIE as it does not have sufficient equity at risk to finance its activities and requires subordinated financial support from Enbridge and other partners. We have determined that we do not have the power to direct the activities of Gray Oak Holdings that most significantly impact its economic performance. Specifically, the power to direct the activities of the VIE is shared amongst the partners. Each partner has representatives that make up an executive committee that makes the significant decisions for the VIE and none of the partners may make significant decisions unilaterally. Therefore, the VIE is accounted for as an unconsolidated VIE.

**NEXUS Gas Transmission, LLC**
NEXUS is a joint venture that engages in transmission of natural gas received from Appalachian shale gas supplies to markets in the United States midwest, as well as Ontario, Canada was previously classified as a VIE.

The NEXUS pipeline construction was completed and the pipeline was placed into service in October 2018. After NEXUS received the last significant equity contribution, it became capable of financing its own operations without any additional subordinated financial support. As a result, it was concluded that NEXUS was no longer a VIE due to sufficient equity at risk to finance its activities.

**Illinois Extension Pipeline Company, L.L.C.**
Illinois Extension Pipeline Company, L.L.C. owns the Southern Access Extension Pipeline. It was previously classified as a VIE.

After Illinois Extension Pipeline Company, L.L.C. received the last significant equity contribution, it became capable of financing its own operations without any additional subordinated financial support. As a result, it was concluded that Illinois Extension Pipeline Company, L.L.C. was no longer a VIE due to sufficient equity at risk to finance its activities.

# 13. LONG-TERM INVESTMENTS

| December 31, | Ownership Interest | 2019 | 2018 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **EQUITY INVESTMENTS** | | | |
| Liquids Pipelines | | | |
| MarEn Bakken Company L.L.C.[1] | 75.0% | **1,892** | 2,039 |
| Gray Oak Holdings L.L.C.[2] | 35.0% | **463** | — |
| Seaway Crude Pipeline System | 50.0% | **2,907** | 3,113 |
| Illinois Extension Pipeline Company, L.L.C.[3] | 65.0% | **662** | 724 |
| Other | 30.0% - 43.8% | **73** | 97 |
| Gas Transmission and Midstream | | | |
| Alliance Pipeline | 50.0% | **310** | 368 |
| Aux Sable | 42.7% - 50.0% | **267** | 311 |
| DCP Midstream, LLC | 50.0% | **2,193** | 2,368 |
| Gulfstream Natural Gas System, L.L.C. | 50.0% | **1,213** | 1,289 |
| NEXUS Gas Transmission, LLC | 50.0% | **1,778** | 1,757 |
| Offshore - various joint ventures | 22.0% - 74.3% | **362** | 400 |
| PennEast Pipeline Company LLC | 20.0% | **106** | 97 |
| Sabal Trail Transmission, LLC | 50.0% | **1,533** | 1,586 |
| Southeast Supply Header L.L.C. | 50.0% | **484** | 519 |
| Steckman Ridge LP | 49.5% | **222** | 237 |
| Vector Pipeline L.P. | 60.0% | **195** | 198 |
| Other | 33.3% - 50.0% | **5** | 6 |
| Gas Distribution and Storage | | | |
| Noverco Common Shares | 38.9% | **95** | — |
| Other | 50.0% | **14** | 15 |
| Renewable Power Generation | | | |
| Eolien Maritime France SAS | 50.0% | **67** | 68 |
| Enbridge Renewable Infrastructure Investments S.a.r.l.[4] | 51.0% | **141** | 127 |
| Rampion Offshore Wind Project | 24.9% | **600** | 638 |
| Other | 21.0% - 50.0% | **127** | 72 |
| Eliminations and Other | | | |
| Other | 42.7% - 50% | **16** | 10 |
| **OTHER LONG-TERM INVESTMENTS** | | | |
| Gas Distribution and Storage | | | |
| Noverco Preferred Shares | | **580** | 478 |
| Renewable Power Generation | | | |
| Emerging Technologies and Other | | **78** | 80 |
| Eliminations and Other | | | |
| Other | | **145** | 110 |
| | | **16,528** | 16,707 |

*1 Owns 49% interest in Bakken Pipeline Investments L.L.C., which owns 75% of the Bakken Pipeline System resulting in a 27.6% effective interest in the Bakken Pipeline System.*

*2 In December 2018 we acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings, L.L.C. (Note 12).*

*3 Owns the Southern Access Extension Project.*

*4 In 2018 we sold a 49% interest in the Hohe See Offshore wind facilities to CPPIB, reducing our effective interest in the project to 25.5%.*

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2019, this comprised of $2.1 billion in Goodwill and $681 million in amortizable assets. As at December 31, 2018, this comprised of $2.2 billion in Goodwill and $706 million in amortizable assets.

For the years ended December 31, 2019, 2018 and 2017, distributions received from equity investments were $2.2 billion, $2.8 billion and $1.4 billion, respectively.

Summarized combined financial information of our interest in unconsolidated equity investments (presented at 100%) is as follows:

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2019** | | | 2018 | | | 2017 | | |
| | **Seaway** | **Other** | **Total** | Seaway | Other | Total | Seaway | Other | Total |
| *(millions of Canadian dollars)* | | | | | | | | | |
| Operating revenues | **1,252** | **14,435** | **15,687** | 966 | 18,251 | 19,217 | 959 | 15,254 | 16,213 |
| Operating expenses | **428** | **12,725** | **13,153** | 212 | 15,422 | 15,634 | 286 | 12,911 | 13,197 |
| Earnings | **818** | **2,198** | **3,016** | 646 | 2,308 | 2,954 | 672 | 2,056 | 2,728 |
| Earnings attributable to Enbridge | **409** | **950** | **1,359** | 323 | 1,059 | 1,382 | 336 | 926 | 1,262 |

| | **December 31, 2019** | | | December 31, 2018 | | |
|---|---|---|---|---|---|---|
| | **Seaway** | **Other** | **Total** | Seaway | Other | Total |
| *(millions of Canadian dollars)* | | | | | | |
| Current assets | **107** | **2,374** | **2,481** | 113 | 3,176 | 3,289 |
| Non-current assets | **3,404** | **45,538** | **48,942** | 3,585 | 45,531 | 49,116 |
| Current liabilities | **136** | **3,911** | **4,047** | 123 | 5,413 | 5,536 |
| Non-current liabilities | **45** | **18,081** | **18,126** | 16 | 15,859 | 15,875 |
| Noncontrolling interests | **—** | **2,779** | **2,779** | — | 3,479 | 3,479 |

**Noverco Inc.**

As at December 31, 2019 and 2018, we owned an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a margin of 4.38%.

As at December 31, 2019 and 2018, Noverco owned an approximate 0.5% and 1.4% reciprocal shareholding in our common shares, respectively. Noverco sold 11.6 million common shares in January 2019 and 4.4 million common shares in December 2018. Shares purchased and sold were treated as treasury stock on the Consolidated Statements of Changes in Equity.

As a result of Noverco's reciprocal shareholding in our common shares, as at December 31, 2019 and 2018, we had an indirect pro-rata interest of 0.2% and 0.5%, respectively, in our own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $51 million and $88 million as at December 31, 2019 and 2018. Noverco records dividends paid from us as dividend income and we eliminate these dividends from our equity earnings of Noverco. We record our pro-rata share of dividends paid by us to Noverco as a reduction of dividends paid and an increase in our investment in Noverco.

## 14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues on the Consolidated Statements of Earnings and Restricted long-term investments on the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense on the Consolidated Statements of Earnings and Other long-term liabilities on the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the United States and Canada.

As at December 31, 2019 and 2018, we had restricted long-term investments held in trust and classified as available for sale or held to maturity of $434 million and $323 million, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $454 million and $328 million as at December 31, 2019 and 2018, respectively.

## 15. INTANGIBLE ASSETS

The following table provides the weighted average amortization rate, gross carrying value, accumulated amortization and net carrying value for each of our major classes of intangible assets:

| **December 31, 2019**[1] | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Customer relationships | 5.4% | **861** | **(231)** | **630** |
| Power purchase agreements | 4.5% | **64** | **(16)** | **48** |
| Project agreement[2] | 4.0% | **156** | **(16)** | **140** |
| Software | 11.2% | **1,988** | **(1,014)** | **974** |
| Other intangible assets[3] | 2.9% | **463** | **(82)** | **381** |
| | | **3,532** | **(1,359)** | **2,173** |

| December 31, 2018[1] | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Customer relationships | 5.7% | 889 | (187) | 702 |
| Power purchase agreements | 5.4% | 82 | (15) | 67 |
| Project agreement[2] | 4.0% | 164 | (10) | 154 |
| Software | 10.0% | 1,902 | (875) | 1,027 |
| Other intangible assets[3] | 2.0% | 485 | (63) | 422 |
| | | 3,522 | (1,150) | 2,372 |

*1 Certain assets were reclassified as held for sale as at December 31, 2019 and December 31, 2018 (Note 8).*
*2 Represents a project agreement acquired from the Merger Transaction (Note 8).*
*3 The measurement of weighted average amortization rate excludes non-depreciable intangible assets.*

For the years ended December 31, 2019, 2018 and 2017, our amortization expense related to intangible assets totaled $296 million, $281 million and $280 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Forecast of amortization expense *(millions of Canadian dollars)* | 292 | 263 | 238 | 216 | 195 |

## 16. GOODWILL

| | Liquids Pipelines | Gas Transmission and Midstream | Gas Distribution and Storage | Renewable Power Generation | Energy Services | Eliminations and Other | Consolidated |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| **Gross Cost** | | | | | | | |
| Balance at January 1, 2018 | 7,786 | 21,539 | 5,679 | — | 2 | 13 | 35,019 |
| Disposition | — | (628) | — | — | — | — | (628) |
| Allocation to assets held for sale | — | (55) | (133) | — | — | — | (188) |
| Foreign exchange and other | 538 | 1,482 | (183) | — | — | — | 1,837 |
| Balance at December 31, 2018 | 8,324 | 22,338 | 5,363 | — | 2 | 13 | 36,040 |
| Foreign exchange and other | **(373)** | **(933)** | **—** | **—** | **—** | **—** | **(1,306)** |
| Balance at December 31, 2019 | **7,951** | **21,405** | **5,363** | **—** | **2** | **13** | **34,734** |
| **Accumulated Impairment** | | | | | | | |
| Balance at January 1, 2018 | — | (542) | (7) | — | — | (13) | (562) |
| Impairment | — | (1,019) | — | — | — | — | (1,019) |
| Balance at December 31, 2018 | — | (1,561) | (7) | — | — | (13) | (1,581) |
| Balance at December 31, 2019 | **—** | **(1,561)** | **(7)** | **—** | **—** | **(13)** | **(1,581)** |
| **Carrying Value** | | | | | | | |
| Balance at December 31, 2018 | 8,324 | 20,777 | 5,356 | — | 2 | — | 34,459 |
| Balance at December 31, 2019 | **7,951** | **19,844** | **5,356** | **—** | **2** | **—** | **33,153** |

**IMPAIRMENT**

**Gas Transmission and Midstream**

**Canadian Natural Gas Gathering and Processing Businesses**

During the year ended December 31, 2018, we recorded a goodwill impairment charge of $1,019 million related to our Canadian Natural Gas Gathering and Processing Businesses assets which were classified as held for sale in the third quarter of 2018. The provincially regulated assets were subsequently sold in the fourth quarter of 2018 (*Note 8*). As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. In connection with the write-down of the carrying values of the assets held for sale to its sale price consideration less costs to sell, the related goodwill was impaired. We also performed a goodwill impairment test for the related reporting unit resulting in no additional impairment charge.

**US Midstream**

During the year ended December 31, 2017, we recorded a goodwill impairment charge of $102 million related to certain assets in our Gas Transmission and Midstream segment classified as held for sale (*Note 8*). Goodwill was allocated to certain disposal groups qualifying as a business based on a relative fair value approach. In connection with the write-down of the carrying values of the assets held for sale to its fair value less costs to sell, the related goodwill was impaired. The fair values of these assets were estimated using the discounted cash flow method, which was negatively impacted by a prolonged decline in commodity prices and deteriorating business performance. We also performed goodwill impairment testing on the associated gas midstream reporting unit resulting in no additional impairment charge.

The estimate of the gas midstream reporting unit's fair value required the use of significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of the reporting unit.

**DISPOSITIONS**

In 2018, we derecognized $262 million of goodwill on the disposition of Midcoast Operating, L.P. and its subsidiaries and $366 million on the disposition of the provincially regulated facilities of our Canadian Natural Gas Gathering and Processing Business (*Note 8*).

**ACQUISITIONS**

In 2017, we recognized $36.7 billion of goodwill on the Merger Transaction (*Note 8*).

## 17. ACCOUNTS PAYABLE AND OTHER

| December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Trade payables and operating accrued liabilities | **4,536** | 4,604 |
| Construction payables and contractor holdbacks | **804** | 804 |
| Current derivative liabilities | **920** | 1,234 |
| Dividends payable | **1,678** | 1,539 |
| Taxes payable | **890** | 801 |
| Current deferred credits | **652** | 850 |
| Other | **583** | 31 |
| | **10,063** | 9,863 |

## 18. DEBT

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (together, the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. See *Note 32 - Condensed Consolidating Financial Information* for further discussion.

| December 31, | Weighted Average Interest Rate[22] | Maturity | 2019 | 2018 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Enbridge Inc. | | | | |
| United States dollar senior notes[1] | 3.8% | 2022-2049 | **8,689** | 6,419 |
| Medium-term notes | 4.2% | 2020-2064 | **7,623** | 7,323 |
| Fixed-to-floating rate subordinated term notes[2,3] | 5.9% | 2077-2078 | **6,550** | 6,771 |
| Floating rate notes[4] | | 2020 | **1,556** | 2,389 |
| Commercial paper and credit facility draws[5] | 1.9% | 2021-2024 | **5,210** | 1,999 |
| Other[6] | | | **5** | 4 |
| Enbridge (U.S.) Inc. | | | | |
| Commercial paper and credit facility draws[7] | 2.1% | 2021-2024 | **1,734** | 1,065 |
| Enbridge Energy Partners, L.P. | | | | |
| Senior notes[8] | 6.0% | 2021-2045 | **3,955** | 6,214 |
| Junior subordinated notes[9] | | | **—** | 546 |
| Commercial paper and credit facility draws[10] | | | **—** | 1,044 |
| Enbridge Gas Distribution Inc.[11] | | | | |
| Medium-term notes | | | **—** | 3,695 |
| Debentures | | | **—** | 85 |
| Commercial paper and credit facility draws | | | **—** | 750 |
| Enbridge Gas Inc.[11] | | | | |
| Medium-term notes | 4.2% | 2020-2050 | **7,685** | — |
| Debentures | 9.1% | 2024-2025 | **210** | — |
| Commercial paper and credit facility draws | 2.0% | 2021 | **898** | — |
| Enbridge Pipelines (Southern Lights) L.L.C. | | | | |
| Senior notes[12] | 4.0% | 2040 | **1,129** | 1,257 |
| Enbridge Pipelines Inc. | | | | |
| Medium-term notes[13] | 4.2% | 2020-2049 | **5,125** | 4,225 |
| Debentures | 8.2% | 2024 | **200** | 200 |
| Commercial paper and credit facility draws[14] | 2.0% | 2021 | **2,030** | 2,200 |
| Enbridge Southern Lights LP | | | | |
| Senior notes | 4.0% | 2040 | **272** | 289 |
| Spectra Energy Capital, LLC | | | | |
| Senior notes[15] | 7.1% | 2032-2038 | **224** | 236 |
| Spectra Energy Partners, LP | | | | |
| Senior secured notes[16] | 6.1% | 2020 | **143** | 150 |
| Senior notes[17] | 4.2% | 2020-2048 | **8,481** | 8,249 |
| Floating rate notes[18] | | 2020 | **519** | 546 |
| Commercial paper and credit facility draws[19] | | | **—** | 2,065 |
| Union Gas Limited[11] | | | | |
| Medium-term notes | | | **—** | 3,290 |
| Debentures | | | **—** | 125 |
| Commercial paper and credit facility draws | | | **—** | 275 |
| Westcoast Energy Inc. | | | | |
| Senior secured notes | | | **—** | 33 |
| Medium-term notes | 4.5% | 2020-2041 | **1,875** | 2,175 |
| Debentures | 8.6% | 2020-2026 | **375** | 375 |
| Fair value adjustment - Merger Transaction | | | **844** | 964 |
| Other[20] | | | **(369)** | (348) |
| Total debt | | | **64,963** | 64,610 |
| Current maturities | | | **(4,404)** | (3,259) |
| Short-term borrowings[21] | | | **(898)** | (1,024) |
| Long-term debt | | | **59,661** | 60,327 |

*1 2019 - US$6,700 million; 2018 - US$4,700 million.*

*2 2019 - $2,400 million and US$3,200 million; 2018 - $2,400 million and US$3,200 million. For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal the Canadian Dollar Offered Rate (CDOR) or the London Interbank Offered Rate (LIBOR) plus a margin.*

*3 The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*

*4 2019 - US$1,200 million; 2018 - $750 million and US$1,200 million. Carries an interest rate equal to the three-month Bankers' Acceptance Rate plus a margin of 59 basis points or LIBOR plus a margin of 40 or 70 basis points.*

*5 2019 - $5,210 million; 2018 - $1,906 million and US$69 million.*

*6 Primarily capital lease obligations.*

*7 2019 - US$1,337 million; 2018 - US$780 million.*

*8 2019 - US$3,050 million; 2018 - US$4,550 million.*

*9 2018 - US$400 million.*
*10 2018 - US$764 million.*
*11 Reflects the amalgamation of EGD and Union Gas into Enbridge Gas Inc.*
*12 2019 - US$871 million; 2018 - US$920 million.*
*13 Included in medium-term notes is $100 million with a maturity date of 2112.*
*14 2019 - $1,570 million and US$355 million; 2018 - $1,905 million and US$216 million.*
*15 2019 - US$173 million; 2018 - US$173 million.*
*16 2019 - US$110 million; 2018 - US$110 million.*
*17 2019 - US$6,540 million; 2018 - US$6,040 million.*
*18 2019 - US$400 million; 2018 - US$400 million. Carries an interest rate equal to the three-month LIBOR plus a margin of 70 basis points.*
*19 2018 - US$1,512 million.*
*20 Primarily unamortized discounts and debt issuance costs.*
*21 Weighted average interest rates on outstanding commercial paper were 2.0% as at December 31, 2019 (2018 - 2.3%).*
*22 Calculated based on term notes and commercial paper and credit facility draws balances outstanding as at December 31, 2019.*

**SECURED DEBT**

Senior secured notes, totaling $143 million as at December 31, 2019, include project financings for the Express-Platte System. Express-Platte System notes payable are secured by the assignment of the Express-Platte System transportation receivables and by the Canadian portion of the Express-Platte pipeline system assets.

**CREDIT FACILITIES**

The following table provides details of our committed credit facilities as at December 31, 2019:

| | Maturity | Total Facilities | Draws[1] | Available |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Enbridge Inc. | 2021-2024 | **6,993** | **5,210** | **1,783** |
| Enbridge (U.S.) Inc. | 2021-2024 | **7,132** | **1,734** | **5,398** |
| Enbridge Pipelines Inc. | 2021[2] | **3,000** | **2,030** | **970** |
| Enbridge Gas Inc. | 2021[2] | **2,000** | **898** | **1,102** |
| Total committed credit facilities | | **19,125** | **9,872** | **9,253** |

*1 Includes facility draws and commercial paper issuances that are back-stopped by the credit facility.*
*2 Maturity date is inclusive of the one year term out option.*

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, Enbridge Gas, EEP and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and Enbridge Gas. As a result, our total credit facility availability increased by approximately $444 million.

On May 16, 2019, Enbridge Inc. entered into a three year, non-revolving, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

On July 18, 2019, Enbridge Inc. entered into a five year, non-revolving, bilateral credit facility for $500 million with an Asian bank.

In addition to the committed credit facilities noted above, we maintain $916 million of uncommitted demand credit facilities, of which $476 million were unutilized as at December 31, 2019. As at December 31, 2018, we had $807 million of uncommitted credit facilities, of which $548 million were unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2021 to 2024.

As at December 31, 2019 and 2018, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $8,974 million and $7,967 million, respectively, are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

**LONG-TERM DEBT ISSUANCES**

During the years ended December 31, 2019 and 2018, we completed the following long-term debt issuances, excluding the debt exchange discussed below:

| Company | Issue Date | | Principal Amount |
|---|---|---|---|
| *(millions of Canadian dollars unless otherwise stated)* | | | |
| Enbridge Inc. | | | |
| | October 2019 | 2.99% medium-term notes due October 2029 | $1,000 |
| | November 2019 | 2.50% senior notes due July 2025 | US$500 |
| | November 2019 | 3.13% senior notes due November 2029 | US$1,000 |
| | November 2019 | 4.00% senior notes due November 2049 | US$500 |
| | March 2018 | Fixed-to-floating rate subordinated notes due March 2078[1] | US$850 |
| | April 2018 | Fixed-to-floating rate subordinated notes due April 2078[2] | $750 |
| | April 2018 | Fixed-to-floating rate subordinated notes due April 2078[3] | US$600 |
| Enbridge Gas Inc. | | | |
| | August 2019 | 2.37% medium-term notes due August 2029 | $400 |
| | August 2019 | 3.01% medium-term notes due August 2049 | $300 |
| Enbridge Pipelines Inc. | | | |
| | February 2019 | 3.52% medium-term notes due February 2029 | $600 |
| | February 2019 | 4.33% medium-term notes due February 2049 | $600 |
| Spectra Energy Partners, LP | | | |
| | August 2019 | 3.24% senior notes due August 2029[4] | US$500 |
| | January 2018 | 3.50% senior notes due January 2028[5] | US$400 |
| | January 2018 | 4.15% senior notes due January 2048[5] | US$400 |

*1 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.25%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 364 basis points from years 10 to 30, and a margin of 439 basis points from years 30 to 60.*

*2 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.625%. Subsequently, the interest rate will be set to equal CDOR plus a margin of 432 basis points from years 10 to 30, and a margin of 507 basis points from years 30 to 60.*

*3 Notes mature in 60 years and are callable on or after year five. For the initial five years, the notes carry a fixed interest rate of 6.375%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 359 basis points from years five to 10, a margin of 384 basis points from years 10 to 25, and a margin of 459 basis points from years 25 to 60.*

*4 Issued through Algonquin Gas Transmission, LLC, an operating subsidiary of SEP.*

*5 Issued through Texas Eastern, a wholly-owned operating subsidiary of SEP.*

**LONG-TERM DEBT REPAYMENTS**

During the years ended December 31, 2019 and 2018, we completed the following long-term debt repayments, excluding the debt exchange discussed below:

| Company | Retirement/Repayment Date | | Principal Amount | Cash Consideration[1] |
|---|---|---|---|---|
| *(millions of Canadian dollars unless otherwise stated)* | | | | |
| Enbridge Inc. | | | | |
| Repayment | | | | |
| | February 2019 | 4.10% medium-term notes | $300 | |
| | May 2019 | Floating rate notes | $750 | |
| | September 2019 | 4.77% medium-term notes | $400 | |
| Enbridge Energy Partners, L.P. | | | | |
| Redemption | | | | |
| | February 2019 | 8.05% fixed/floating rate junior subordinated notes due 2067 | US$400 | |
| | December 2019 | 5.20% senior notes due 2020 | US$500 | US$504 |
| | December 2019 | 4.38% senior notes due 2020 | US$500 | US$509 |
| Repayment | | | | |
| | March 2019 | 9.88% senior notes | US$500 | |
| | April 2018 | 6.50% senior notes | US$400 | |
| | October 2018 | 7.00% senior notes | US$100 | |
| Enbridge Income Fund | | | | |
| Repayment | | | | |
| | December 2018 | 4.00% medium-term notes | $125 | |
| Enbridge Pipelines (Southern Lights) L.L.C. | | | | |
| Repayment | | | | |
| | June and December 2019 | 3.98% senior notes due 2040 | US$49 | |
| | June and December 2018 | 3.98% senior notes due 2040 | US$43 | |
| Enbridge Pipelines Inc. | | | | |
| Repayment | | | | |
| | November 2019 | 4.49% medium-term notes | $200 | |
| | November 2019 | 4.49% medium-term notes | $100 | |
| | November 2018 | 6.62% medium-term notes | $170 | |
| | November 2018 | 6.62% medium-term notes | $130 | |
| Enbridge Southern Lights LP | | | | |
| Repayment | | | | |
| | July and December 2019 | 4.01% senior notes due 2040 | $17 | |
| | January, July and December 2018 | 4.01% senior notes due 2040 | $27 | |
| Midcoast Energy Partners, L.P. | | | | |
| Redemption | | | | |
| | July 2018[2] | 3.56% senior notes due 2019 | US$75 | US$76 |
| | July 2018[2] | 4.04% senior notes due 2021 | US$175 | US$182 |
| | July 2018[2] | 4.42% senior notes due 2024 | US$150 | US$161 |
| Spectra Energy Capital, LLC | | | | |
| Repurchase via Tender Offer | | | | |
| | March 2018[2] | 6.75% senior unsecured notes due 2032 | US$64 | US$80 |
| | March 2018[2] | 7.50% senior unsecured notes due 2038 | US$43 | US$59 |
| Redemption | | | | |
| | March 2018[2] | 5.65% senior unsecured notes due 2020 | US$163 | US$172 |
| | March 2018[2] | 3.30% senior unsecured notes due 2023 | US$498 | US$508 |
| Repayment | | | | |
| | April 2018 | 6.20% senior notes | US$272 | |
| | July 2018 | 6.75% senior notes | US$118 | |
| Spectra Energy Partners, LP | | | | |
| Repayment | | | | |
| | September 2018 | 2.95% senior notes | US$500 | |

| | | | |
|---|---|---|---|
| Union Gas Limited | | | |
| Repayment | | | |
| | April 2018 | 5.35% medium-term notes | $200 |
| | August 2018 | 8.75% debentures | $125 |
| | October 2018 | 8.65% senior debentures | $75 |
| Westcoast Energy Inc. | | | |
| Repayment | | | |
| | January 2019 | 5.60% medium-term notes | $250 |
| | January 2019 | 5.60% medium-term notes | $50 |
| | May and November 2019 | 6.90% senior secured notes | $26 |
| | May and November 2019 | 4.34% senior secured notes | $5 |
| | December 2019 | 1.00% senior secured notes | $2 |
| | May and November 2018 | 6.90% senior secured notes due 2019 | $26 |
| | May and November 2018 | 4.34% senior secured notes due 2019 | $9 |
| | September 2018 | 8.50% debentures | $150 |

*1 Cash consideration disclosed for repayments where the cash paid differs from the principal amount.*

*2 The loss on debt extinguishment of $64 million (US$50 million), net of the fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.*

**DEBT EXCHANGE**

On December 21, 2018, Enbridge and the Fund completed a transaction to exchange certain series of the Legacy Fund Notes for an equal principal amount of newly issued medium-term notes of Enbridge, having financial terms that are the same as the financial terms of the Fund Notes.

**DEBT COVENANTS**

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2019, we were in compliance with all debt covenants.

**INTEREST EXPENSE**

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Debentures and term notes | **2,783** | 3,011 | 3,011 |
| Commercial paper and credit facility draws | **273** | 171 | 206 |
| Amortization of fair value adjustment - Spectra Energy acquisition | **(67)** | (131) | (270) |
| Capitalized | **(326)** | (348) | (391) |
| | **2,663** | 2,703 | 2,556 |

## 19. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets, obligations related to right-of way agreements and contractual leases for land use.

The liability for the expected cash flows as recognized in the financial statements reflected discount rates ranging from 1.8% to 9.0%.

A reconciliation of movements in our ARO liabilities is as follows:

| December 31, | 2019 | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Obligations at beginning of year | **989** | 793 |
| Liabilities acquired | **—** | — |
| Liabilities disposed | **(59)** | (13) |
| Liabilities incurred | **15** | 145 |
| Liabilities settled | **(12)** | (21) |
| Change in estimate and other | **(417)** | 29 |
| Foreign currency translation adjustment | **(18)** | 22 |
| Accretion expense | **22** | 34 |
| Obligations at end of year | **520** | 989 |
| Presented as follows: | | |
| Accounts payable and other | **7** | 6 |
| Other long-term liabilities | **513** | 983 |
| | **520** | 989 |

## 20. NONCONTROLLING INTERESTS

**NONCONTROLLING INTERESTS**

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

| December 31, | 2019 | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Algonquin Gas Transmission, L.L.C | **394** | 518 |
| Maritimes & Northeast Pipeline, L.L.C | **579** | 613 |
| Renewable energy assets[1] | **1,864** | 1,961 |
| Westcoast Energy Inc.[2] | **527** | 841 |
| Other | **—** | 32 |
| | **3,364** | 3,965 |

*1 On August 1, 2018, we closed the sale of 49% of our interest in the Renewable Assets (Note 8). The remaining balance represents the tax equity investors' interests in Magic Valley, Wildcat, Keechi, New Creek and Chapman Ranch wind facilities, with an additional 20.0% noncontrolling interest in each of the Magic Valley and Wildcat wind facilities held by third parties as at December 31, 2019 and 2018.*

*2 Represents the 16.6 million cumulative redeemable preferred shares as at December 31, 2019 and 2018, nil and 12 million cumulative first preferred shares as at December 31, 2019 and 2018, respectively, held by third parties in Westcoast Energy Inc., in addition to the 22.2% interest in Maritimes & Northeast Pipeline Limited Partnership held by third parties as at December 31, 2019 and 2018.*

**United States Sponsored Vehicles Buy-in**

On August 24, 2018, we entered into a definitive agreement with SEP under which we agreed to acquire all of the outstanding public common units of SEP not already owned by us or our subsidiaries on the basis of 1.111 of our common shares for each common unit of SEP. Upon the closing of the transaction on December 17, 2018, we acquired all of the public common units of SEP and SEP became an indirect, wholly-owned subsidiary of Enbridge. The transaction is valued at $3.9 billion based on the closing price of our common shares on the New York Stock Exchange on December 14, 2018. As a result of this buy-in, we recorded a decrease in Noncontrolling interests, Additional paid-in capital and Deferred income tax liabilities of $3.0 billion, $642 million and $167 million, respectively.

On September 17, 2018, we entered into definitive agreements with each of EEP and EEM under which we agreed to acquire all of the outstanding public class A common units of EEP and all of the outstanding public listed shares of EEM not already owned by us or our subsidiaries. Under the agreements, EEP public unitholders received 0.335 of our common shares for each class A common unit of EEP, and EEM public shareholders received 0.335 of our common shares for each listed share of EEM. Upon the closing of the respective transactions on December 20, 2018, we acquired all of the public Class A common units of EEP and shares of EEM, and both EEP and EEM became indirect, wholly-owned subsidiaries of Enbridge. The EEP and EEM transactions are valued at $3.0 billion and $1.3 billion, respectively, based on the closing price of our common shares on the New York Stock Exchange on December 19, 2018. As a result of the buy-ins, collectedly for EEP and EEM, we recorded an increase in Noncontrolling interests and a decrease in Additional paid-in capital and Deferred income tax liabilities of $185 million, $3.7 billion and $707 million, respectively.

For discussion on the roll-up of ENF, refer to *Canadian Sponsored Vehicles Buy-in* under *Redeemable Noncontrolling Interests* below.

**Renewable Assets**
On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets and a 49% interest in two United States renewable assets to CPPIB *(Note 8)*. As a result, we recorded an increase in Noncontrolling interests, Additional paid-in capital and Deferred income tax liabilities of $1,183 million, $79 million and $27 million, respectively, in the third quarter of 2018. For 2018 and 2019, CPPIB's distributions and allocation of earnings were not proportionate to its ownership.

**SEP Incentive Distribution Rights**
On January 22, 2018, Enbridge and SEP announced the execution of a definitive agreement, resulting in us converting all of our ownership of incentive distribution rights (IDRs) and general partner economic interests in SEP into 172.5 million newly issued SEP common units. As part of the transaction, all of the IDRs were eliminated. As a result of this restructuring, in 2018 we recorded a decrease in Noncontrolling interests of $1.5 billion and increases in Additional paid-in capital and Deferred income tax liabilities of $1.1 billion and $333 million, respectively. Subsequently in 2018, we acquired all of the outstanding common units of SEP (refer to *United States Sponsored Vehicles Buy-in* above).

**EEP Sponsored Vehicle Strategy**
On April 28, 2017, we completed a strategic review of EEP and took actions including acquisition of all EEP's interest in the Midcoast assets and privatization of Midcoast Energy Partners, L.P. As a result of these actions, we recorded an increase in Noncontrolling interests of $458 million, inclusive of foreign currency translation adjustments, and a decrease in Additional paid-in capital of $421 million, net of deferred income taxes of $253 million.

**Westcoast Preferred Shares Redemption**
On March 20, 2019, Westcoast Energy Inc. exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 (Series 7 Shares) and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 (Series 8 Shares) at a price of $25.00 per Series 7 Share and $25.00 per Series 8 Share, respectively, for a total payment of $300 million. In addition, payment of $4 million was made for all accrued and unpaid dividends. As a result, we recorded a $300 million decrease in Noncontrolling interests.

**REDEEMABLE NONCONTROLLING INTERESTS**

The following table presents additional information regarding Redeemable noncontrolling interests as presented in our Consolidated Statements of Financial Position:

| Year ended December 31, | 2018 | 2017 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Balance at beginning of year | 4,067 | 3,392 |
| Earnings attributable to redeemable noncontrolling interests | 117 | 175 |
| Other comprehensive income/(loss), net of tax | | |
| Change in unrealized loss on cash flow hedges | 3 | (21) |
| Other comprehensive loss from equity investees | 14 | — |
| Reclassification to earnings of loss on cash flow hedges | — | 57 |
| Foreign currency translation adjustments | 4 | (6) |
| Other comprehensive income/(loss), net of tax | 21 | 30 |
| Distributions to unitholders | (300) | (247) |
| Contributions from unitholders | 70 | 1,178 |
| Modified retrospective adoption of accounting standard | (38) | — |
| Net dilution gain/(loss) | 76 | (169) |
| Redemption value adjustment | 456 | (292) |
| Sponsored vehicle buy-in[1] | (4,469) | — |
| Balance at end of year | — | 4,067 |

*1 On November 8, 2018, we executed the definitive agreement with ENF and acquired all of the publicly held shares of ENF not already owned by us or our subsidiaries.*

**Canadian Sponsored Vehicle Buy-in**

On September 17, 2018, we entered into a definitive agreement with ENF under which we would acquire all of the outstanding public common shares of ENF not already owned by us or our subsidiaries on the basis of 0.735 of our common shares and cash of $0.45 for each common share of ENF. Upon the closing of the transaction on November 8, 2018, we acquired all of the public common shares of ENF and ENF become a wholly-owned subsidiary of Enbridge. The transaction, excluding the cash component, is valued at $4.5 billion based on the closing price of our common shares on the Toronto Stock Exchange on November 7, 2018. As a result of this buy-in, we recorded a decrease in Redeemable noncontrolling interests and Additional paid-in capital of $4.5 billion and $25 million, respectively, with nil deferred tax impact. As at December 31, 2018, the balance of Redeemable noncontrolling interests was nil.

## 21. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

**COMMON SHARES**

| December 31, | **2019** Number of Shares | **2019** Amount | 2018 Number of Shares | 2018 Amount | 2017 Number of Shares | 2017 Amount |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars; number of shares in millions)* | | | | | | |
| Balance at beginning of year | **2,022** | **64,677** | 1,695 | 50,737 | 943 | 10,492 |
| Common shares issued | **—** | **—** | — | — | 33 | 1,500 |
| Common shares issued in Merger Transaction *(Note 8)* | **—** | **—** | — | — | 691 | 37,429 |
| Common shares issued in Sponsored Vehicle buy-in (SEP) *(Note 20)* | **—** | **—** | 91 | 3,888 | — | — |
| Common shares issued in Sponsored Vehicle buy-in (EEP) *(Note 20)* | **—** | **—** | 72 | 3,042 | — | — |
| Common shares issued in Sponsored Vehicle buy-in (EEM) *(Note 20)* | **—** | **—** | 30 | 1,267 | — | — |
| Common shares issued in Sponsored Vehicle buy-in (ENF) *(Note 20)* | **—** | **—** | 104 | 4,530 | — | — |
| Dividend Reinvestment and Share Purchase Plan | **—** | **—** | 28 | 1,181 | 25 | 1,226 |
| Shares issued on exercise of stock options | **3** | **69** | 2 | 32 | 3 | 90 |
| Balance at end of year | **2,025** | **64,746** | 2,022 | 64,677 | 1,695 | 50,737 |

**PREFERENCE SHARES**

| December 31, | **2019** Number of Shares | **2019** Amount | 2018 Number of Shares | 2018 Amount | 2017 Number of Shares | 2017 Amount |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars; number of shares in millions)* | | | | | | |
| Preference Shares, Series A | **5** | **125** | 5 | 125 | 5 | 125 |
| Preference Shares, Series B | **18** | **457** | 18 | 457 | 18 | 457 |
| Preference Shares, Series C | **2** | **43** | 2 | 43 | 2 | 43 |
| Preference Shares, Series D | **18** | **450** | 18 | 450 | 18 | 450 |
| Preference Shares, Series F | **20** | **500** | 20 | 500 | 20 | 500 |
| Preference Shares, Series H | **14** | **350** | 14 | 350 | 14 | 350 |
| Preference Shares, Series J | **8** | **199** | 8 | 199 | 8 | 199 |
| Preference Shares, Series L | **16** | **411** | 16 | 411 | 16 | 411 |
| Preference Shares, Series N | **18** | **450** | 18 | 450 | 18 | 450 |
| Preference Shares, Series P | **16** | **400** | 16 | 400 | 16 | 400 |
| Preference Shares, Series R | **16** | **400** | 16 | 400 | 16 | 400 |
| Preference Shares, Series 1 | **16** | **411** | 16 | 411 | 16 | 411 |
| Preference Shares, Series 3 | **24** | **600** | 24 | 600 | 24 | 600 |
| Preference Shares, Series 5 | **8** | **206** | 8 | 206 | 8 | 206 |
| Preference Shares, Series 7 | **10** | **250** | 10 | 250 | 10 | 250 |
| Preference Shares, Series 9 | **11** | **275** | 11 | 275 | 11 | 275 |
| Preference Shares, Series 11 | **20** | **500** | 20 | 500 | 20 | 500 |
| Preference Shares, Series 13 | **14** | **350** | 14 | 350 | 14 | 350 |
| Preference Shares, Series 15 | **11** | **275** | 11 | 275 | 11 | 275 |
| Preference Shares, Series 17 | **30** | **750** | 30 | 750 | 30 | 750 |
| Preference Shares, Series 19 | **20** | **500** | 20 | 500 | 20 | 500 |
| Issuance costs | | **(155)** | | (155) | | (155) |
| Balance at end of year | | **7,747** | | 7,747 | | 7,747 |

Characteristics of the preference shares are as follows:

| | Dividend Rate | Dividend[1] | Per Share Base Redemption Value[2] | Redemption and Conversion Option Date[2,3] | Right to Convert Into[3] |
|---|---|---|---|---|---|
| *(Canadian dollars unless otherwise stated)* | | | | | |
| Preference Shares, Series A | 5.50% | $1.37500 | $25 | — | — |
| Preference Shares, Series B | 3.42% | $0.85360 | $25 | June 1, 2022 | Series C |
| Preference Shares, Series C[5] | 3-month treasury bill plus 2.40% | — | $25 | June 1, 2022 | Series B |
| Preference Shares, Series D | 4.46% | $1.11500 | $25 | March 1, 2023 | Series E |
| Preference Shares, Series F | 4.69% | $1.17224 | $25 | June 1, 2023 | Series G |
| Preference Shares, Series H | 4.38% | $1.09400 | $25 | September 1, 2023 | Series I |
| Preference Shares, Series J | 4.89% | US$1.22160 | US$25 | June 1, 2022 | Series K |
| Preference Shares, Series L | 4.96% | US$1.23972 | US$25 | September 1, 2022 | Series M |
| Preference Shares, Series N | 5.09% | $1.27152 | $25 | December 1, 2023 | Series O |
| Preference Shares, Series P[6] | 4.38% | $1.09476 | $25 | March 1, 2024 | Series Q |
| Preference Shares, Series R[6] | 4.07% | $1.01825 | $25 | June 1, 2024 | Series S |
| Preference Shares, Series 1 | 5.95% | US$1.48728 | US$25 | June 1, 2023 | Series 2 |
| Preference Shares, Series 3[6] | 3.74% | $0.93425 | $25 | September 1, 2024 | Series 4 |
| Preference Shares, Series 5[6] | 5.38% | US$1.34383 | US$25 | March 1, 2024 | Series 6 |
| Preference Shares, Series 7[6] | 4.45% | $1.11224 | $25 | March 1, 2024 | Series 8 |
| Preference Shares, Series 9[6] | 4.10% | $1.02424 | $25 | December 1, 2024 | Series 10 |
| Preference Shares, Series 11 | 4.40% | $1.10000 | $25 | March 1, 2020 | Series 12 |
| Preference Shares, Series 13 | 4.40% | $1.10000 | $25 | June 1, 2020 | Series 14 |
| Preference Shares, Series 15 | 4.40% | $1.10000 | $25 | September 1, 2020 | Series 16 |
| Preference Shares, Series 17 | 5.15% | $1.28750 | $25 | March 1, 2022 | Series 18 |
| Preference Shares, Series 19 | 4.90% | $1.22500 | $25 | March 1, 2023 | Series 20 |

*1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.*

*2 Series A Preference Shares may be redeemed any time at our option. For all other series of Preference Shares, we, may at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

*3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

*4 With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x 90 day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US$25 x (number of days in quarter/365) x three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

*5 The floating quarterly dividend amount for the Series C Preference Shares was decreased to $0.25395 from $0.25459 on March 1, 2019, was increased to $0.25647 from $0.25395 on June 1, 2019, was decreased to $0.25243 from $0.25647 on September 1, 2019 and was increased to $0.25305 from $0.25243 on December 1, 2019, due to reset on a quarterly basis following the issuance thereof.*

*6 No Series P, R, 3, 5, 7 or 9 Preference shares were converted on the March 1, 2019, June 1, 2019, September 1, 2019, March 1, 2019, March 1, 2019 or December 1, 2019 conversion option dates, respectively. However, the quarterly dividend amounts for Series P, R, 3, 5, 7 or 9, was increased to $0.27369 from $0.25000 on March 1, 2019, increased to $0.25456 from $0.25000 on June 1, 2019, decreased to $0.23356 from $0.25000 on September 1, 2019, increased to US$0.33625 from US$0.27500 on March 1, 2019, increased to $0.27806 from $0.27500 on March 1, 2019 and decreased to $0.25606 from $0.27500 on December 1, 2019, respectively, due to reset on every fifth anniversary thereafter.*

**DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN**

On November 2, 2018, we announced the suspension of our DRIP, effective immediately. Prior to the announcement, our shareholders were able to participate in the DRIP, which enabled participants to reinvest their dividends in our common shares at a 2% discount to market price and to make additional optional cash payments to purchase common shares at the market price, free of brokerage or other charges. Refer to *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Dividends* for details on dividends paid.

**SHAREHOLDER RIGHTS PLAN**

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for us. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

## 22. STOCK OPTION AND STOCK UNIT PLANS

We maintain four long-term incentive compensation plans: the ISO Plan, the Performance Stock Options (PSO) Plan, the PSU Plan and the RSU Plan. In 2019, Enbridge adopted a new Long Term Incentive Plan with an effective date of February 13, 2019. The 2019 plan replaced several of Enbridge's prior incentive award plans and no additional awards were made or will be made under the prior plans as of the effective date. A reserve of 50 million was approved and established for the 2019 ISO Plan. Awards of PSUs and RUSs are notional units as if a unit was one Enbridge common share and are payable in cash.

Prior to the Merger Transaction, Spectra Energy had a long-term incentive plan providing for the granting of stock options, restricted and unrestricted stock awards and units, and other equity-based awards. Upon closing of the Merger Transaction, Enbridge replaced existing Spectra Energy share-based payment awards with awards that will be settled in shares of Enbridge. Spectra Energy's cash-settled phantom awards were included in the fair value of the net assets acquired *(Note 8).*

Total stock-based compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 was $117 million, $106 million and $165 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

**INCENTIVE STOCK OPTIONS**

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

| **December 31, 2019** | Number | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life *(years)* | Aggregate Intrinsic Value |
|---|---|---|---|---|
| *(options in thousands; intrinsic value in millions of Canadian dollars)* | | | | |
| Options outstanding at beginning of year | **34,387** | **43.47** | | |
| Options granted | **6,777** | **48.32** | | |
| Options exercised[1] | **(4,519)** | **34.19** | | |
| Options cancelled or expired | **(1,598)** | **50.62** | | |
| Options outstanding at end of year | **35,047** | **47.73** | **6.2** | **157** |
| Options vested at end of year[2] | **20,581** | **47.67** | **4.7** | **92** |

*1 The total intrinsic value of ISOs exercised during the years ended December 31, 2019, 2018 and 2017 was $58 million, $42 million and $62 million, respectively, and cash received on exercise was $1 million, $15 million and $17 million, respectively.*

*2 The total fair value of ISOs vested during the years ended December 31, 2019, 2018 and 2017 was $32 million, $36 million and $44 million, respectively.*

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton option pricing model are as follows:

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| Fair value per option *(Canadian dollars)*[1] | **4.37** | 3.86 | 6.00 |
| Valuation assumptions | | | |
| Expected option term *(years)*[2] | **5** | 5 | 5 |
| Expected volatility[3] | **19.9%** | 21.9% | 20.4% |
| Expected dividend yield[4] | **6.1%** | 6.4% | 4.4% |
| Risk-free interest rate[5] | **2.0%** | 2.2% | 1.2% |

*1 Options granted to United States employees are based on NYSE prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option for the years ended December 31, 2019, 2018 and 2017 were $4.04, $3.75 and $5.66, respectively, for Canadian employees and US$4.09, US$3.30 and US$5.72, respectively, for United States employees.*

*2 The expected option term is six years based on historical exercise practice and three years for retirement eligible employees.*

*3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*

*4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

*5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

Compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 for ISOs was $32 million, $28 million and $40 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $18 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

**PERFORMANCE STOCK UNITS**

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of its performance targets. The performance multiplier is derived through a calculation of our Risk Adjusted Total Shareholder Return (in 2017) and Total Shareholder Return (commencing in 2018) percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2019 expense, a multiplier of one was used for each of the 2017, 2018 and 2019 PSU grants.

| **December 31, 2019** | Number | Weighted Average Remaining Contractual Life *(years)* | Aggregate Intrinsic Value |
|---|---|---|---|
| *(units in thousands; intrinsic value in millions of Canadian dollars)* | | | |
| Units outstanding at beginning of year | **1,069** | | |
| Units granted | **1,093** | | |
| Units cancelled | **(65)** | | |
| Units matured[1] | **(25)** | | |
| Dividend reinvestment | **117** | | |
| Units outstanding at end of year | **2,189** | **1.5** | **111** |

*1 The total amount paid during the years ended December 31, 2019, 2018 and 2017 for PSUs was $19 million, $18 million and $28 million, respectively.*

Compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 for PSUs was $40 million, $15 million and $5 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested PSUs was $55 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

**RESTRICTED STOCK UNITS**

Under RSU awards, cash awards are paid to certain of our employees following a 35-month maturity period. RSU holders receive cash equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

| **December 31, 2019** | Number | Weighted Average Remaining Contractual Life *(years)* | Aggregate Intrinsic Value |
|---|---|---|---|
| *(units in thousands; intrinsic value in millions of Canadian dollars)* | | | |
| Units outstanding at beginning of year | **1,213** | | |
| Units granted | **1,087** | | |
| Units cancelled | **(96)** | | |
| Units matured[1] | **(706)** | | |
| Dividend reinvestment | **126** | | |
| Units outstanding at end of year | **1,624** | **1.6** | **82** |

*1 The total amount paid during the years ended December 31, 2019, 2018 and 2017 for RSUs was $34 million, $41 million and $39 million, respectively.*

Compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 for RSUs was $41 million, $32 million and $46 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested RSUs was $47 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

## 23. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2019, 2018 and 2017 are as follows:

| | Cash Flow Hedges | Net Investment Hedges | Cumulative Translation Adjustment | Equity Investees | Pension and OPEB Adjustment | Total |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at January 1, 2019 | **(770)** | **(598)** | **4,323** | **34** | **(317)** | **2,672** |
| Other comprehensive income/(loss) retained in AOCI | **(599)** | **320** | **(2,927)** | **34** | **(124)** | **(3,296)** |
| Other comprehensive (income)/loss reclassified to earnings | | | | | | |
| Interest rate contracts[1] | **157** | **—** | **—** | **—** | **—** | **157** |
| Commodity contracts[2] | **(1)** | **—** | **—** | **—** | **—** | **(1)** |
| Foreign exchange contracts[3] | **5** | **—** | **—** | **—** | **—** | **5** |
| Other contracts[4] | **(3)** | **—** | **—** | **—** | **—** | **(3)** |
| Amortization of pension and OPEB actuarial loss and prior service costs[5] | **—** | **—** | **—** | **—** | **17** | **17** |
| | **(441)** | **320** | **(2,927)** | **34** | **(107)** | **(3,121)** |
| Tax impact | | | | | | |
| Income tax on amounts retained in AOCI | **169** | **(39)** | **—** | **6** | **28** | **164** |
| Income tax on amounts reclassified to earnings | **(31)** | **—** | **—** | **—** | **(4)** | **(35)** |
| | **138** | **(39)** | **—** | **6** | **24** | **129** |
| Other | **—** | **—** | **—** | **(7)** | **55** | **48** |
| Balance at December 31, 2019 | **(1,073)** | **(317)** | **1,396** | **67** | **(345)** | **(272)** |

| | Cash Flow Hedges | Net Investment Hedges | Cumulative Translation Adjustment | Equity Investees | Pension and OPEB Adjustment | Total |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at January 1, 2018 | (644) | (139) | 77 | 10 | (277) | (973) |
| Other comprehensive income/(loss) retained in AOCI | (244) | (509) | 4,301 | 16 | (85) | 3,479 |
| Other comprehensive (income)/loss reclassified to earnings | | | | | | |
| Interest rate contracts[1] | 157 | — | — | — | — | 157 |
| Commodity contracts[2] | (1) | — | — | — | — | (1) |
| Foreign exchange contracts[3] | 7 | — | — | — | — | 7 |
| Other contracts[4] | 22 | — | — | — | — | 22 |
| Amortization of pension and OPEB actuarial loss and prior service costs[5] | — | — | — | — | 16 | 16 |
| | (59) | (509) | 4,301 | 16 | (69) | 3,680 |
| Tax impact | | | | | | |
| Income tax on amounts retained in AOCI | 57 | 50 | — | 8 | 33 | 148 |
| Income tax on amounts reclassified to earnings | (37) | — | — | — | (4) | (41) |
| | 20 | 50 | — | 8 | 29 | 107 |
| Sponsored Vehicles buy-in[6] | (87) | — | (55) | — | — | (142) |
| Balance at December 31, 2018 | (770) | (598) | 4,323 | 34 | (317) | 2,672 |

| | Cash Flow Hedges | Net Investment Hedges | Cumulative Translation Adjustment | Equity Investees | Pension and OPEB Adjustment | Total |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at January 1, 2017 | (746) | (629) | 2,700 | 37 | (304) | 1,058 |
| Other comprehensive income/(loss) retained in AOCI | 1 | 478 | (2,623) | (11) | 18 | (2,137) |
| Other comprehensive (income)/loss reclassified to earnings | | | | | | |
| Interest rate contracts[1] | 207 | — | — | — | — | 207 |
| Commodity contracts[2] | (7) | — | — | — | — | (7) |
| Foreign exchange contracts[3] | (6) | — | — | — | — | (6) |
| Other contracts[4] | (6) | — | — | — | — | (6) |
| Amortization of pension and OPEB actuarial loss and prior service costs[5] | — | — | — | — | 41 | 41 |
| | 189 | 478 | (2,623) | (11) | 59 | (1,908) |
| Tax impact | | | | | | |
| Income tax on amounts retained in AOCI | (16) | 12 | — | (16) | (10) | (30) |
| Income tax on amounts reclassified to earnings | (71) | — | — | — | (22) | (93) |
| | (87) | 12 | — | (16) | (32) | (123) |
| Balance at December 31, 2017 | (644) | (139) | 77 | 10 | (277) | (973) |

*1 Reported within Interest expense in the Consolidated Statements of Earnings.*
*2 Reported within Transportation and other services revenue, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
*3 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.*
*4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
*5 These components are included in the computation of net benefit costs and are reported within Other income/(expense) in the Consolidated Statements of Earnings.*
*6 Represents the historical noncontrolling interests and redeemable noncontrolling interests related to the Sponsored Vehicles reclassified to AOCI, upon the completion of the buy-in.*

## 24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

**MARKET RISK**

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

**Foreign Exchange Risk**

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

**Interest Rate Risk**
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As at December 31, 2019, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3%.

**Commodity Price Risk**
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

**Equity Price Risk**
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

**TOTAL DERIVATIVE INSTRUMENTS**
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances. The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

| December 31, 2019 | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment | Non-Qualifying Derivative Instruments | Total Gross Derivative Instruments as Presented | Amounts Available for Offset | Total Net Derivative Instruments |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Accounts receivable and other | | | | | | |
| Foreign exchange contracts | **—** | **—** | **161** | **161** | **(78)** | **83** |
| Commodity contracts | **—** | **—** | **163** | **163** | **(47)** | **116** |
| Other contracts | **1** | **—** | **3** | **4** | **—** | **4** |
| | **1** | **—** | **327** | **328** [1] | **(125)** | **203** |
| Deferred amounts and other assets | | | | | | |
| Foreign exchange contracts | **10** | **—** | **71** | **81** | **(42)** | **39** |
| Commodity contracts | **—** | **—** | **17** | **17** | **(2)** | **15** |
| Other contracts | **2** | **—** | **1** | **3** | **—** | **3** |
| | **12** | **—** | **89** | **101** | **(44)** | **57** |
| Accounts payable and other | | | | | | |
| Foreign exchange contracts | **(5)** | **(13)** | **(392)** | **(410)** | **78** | **(332)** |
| Interest rate contracts | **(353)** | **—** | **—** | **(353)** | **—** | **(353)** |
| Commodity contracts | **—** | **—** | **(173)** | **(173)** | **47** | **(126)** |
| | **(358)** | **(13)** | **(565)** | **(936)** [2] | **125** | **(811)** |
| Other long-term liabilities | | | | | | |
| Foreign exchange contracts | **—** | **—** | **(934)** | **(934)** | **42** | **(892)** |
| Interest rate contracts | **(181)** | **—** | **—** | **(181)** | **—** | **(181)** |
| Commodity contracts | **(5)** | **—** | **(60)** | **(65)** | **2** | **(63)** |
| | **(186)** | **—** | **(994)** | **(1,180)** | **44** | **(1,136)** |
| Total net derivative asset/(liability) | | | | | | |
| Foreign exchange contracts | **5** | **(13)** | **(1,094)** | **(1,102)** | **—** | **(1,102)** |
| Interest rate contracts | **(534)** | **—** | **—** | **(534)** | **—** | **(534)** |
| Commodity contracts | **(5)** | **—** | **(53)** | **(58)** | **—** | **(58)** |
| Other contracts | **3** | **—** | **4** | **7** | **—** | **7** |
| | **(531)** | **(13)** | **(1,143)** | **(1,687)** | **—** | **(1,687)** |

*1 Reported within Accounts receivable and other (2019 - $327 million; 2018 - $498 million) and Accounts receivable from affiliates (2019 - $1 million; 2018 - nil) on the Consolidated Statements of Financial Position.*

*2 Reported within Accounts payable and other (2019 - $920 million; 2018 - $1,234 million) and Accounts payable to affiliates (2019 - $16 million; 2018 - nil) on the Consolidated Statements of Financial Position.*

| December 31, 2018 | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment Hedges | Non-Qualifying Derivative Instruments | Total Gross Derivative Instruments as Presented | Amounts Available for Offset | Total Net Derivative Instruments |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Accounts receivable and other | | | | | | |
| Foreign exchange contracts | — | — | 47 | 47 | (37) | 10 |
| Interest rate contracts | 22 | — | — | 22 | (2) | 20 |
| Commodity contracts | 2 | — | 427 | 429 | (114) | 315 |
| | 24 | — | 474 | 498 | (153) | 345 |
| Deferred amounts and other assets | | | | | | |
| Foreign exchange contracts | 23 | — | 39 | 62 | (39) | 23 |
| Interest rate contracts | 5 | — | — | 5 | — | 5 |
| Commodity contracts | 19 | — | 33 | 52 | (21) | 31 |
| | 47 | — | 72 | 119 | (60) | 59 |
| Accounts payable and other | | | | | | |
| Foreign exchange contracts | (5) | — | (610) | (615) | 37 | (578) |
| Interest rate contracts | (163) | — | (178) | (341) | 2 | (339) |
| Commodity contracts | — | — | (273) | (273) | 114 | (159) |
| Other contracts | (1) | — | (4) | (5) | — | (5) |
| | (169) | — | (1,065) | (1,234) | 153 | (1,081) |
| Other long-term liabilities | | | | | | |
| Foreign exchange contracts | (1) | (15) | (2,196) | (2,212) | 39 | (2,173) |
| Interest rate contracts | (201) | — | — | (201) | — | (201) |
| Commodity contracts | — | — | (178) | (178) | 21 | (157) |
| Other contracts | (1) | — | (1) | (2) | — | (2) |
| | (203) | (15) | (2,375) | (2,593) | 60 | (2,533) |
| Total net derivative asset/(liability) | | | | | | |
| Foreign exchange contracts | 17 | (15) | (2,720) | (2,718) | — | (2,718) |
| Interest rate contracts | (337) | — | (178) | (515) | — | (515) |
| Commodity contracts | 21 | — | 9 | 30 | — | 30 |
| Other contracts | (2) | — | (5) | (7) | — | (7) |
| | (301) | (15) | (2,894) | (3,210) | — | (3,210) |

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

| | 2019 | | | | | | | 2018 |
|---|---|---|---|---|---|---|---|---|
| As at December 31, | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total | Total |
| Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)* | **1,121** | **—** | **—** | **—** | **—** | **—** | **1,121** | 926 |
| Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)* | **5,631** | **4,946** | **5,182** | **1,804** | **1,856** | **—** | **19,419** | 19,075 |
| Foreign exchange contracts - GBP forwards - sell *(millions of GBP)* | **94** | **27** | **28** | **29** | **30** | **90** | **298** | 318 |
| Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)* | **—** | **—** | **—** | **—** | **—** | **—** | **—** | 226 |
| Foreign exchange contracts - Euro forwards - sell *(millions of Euro)* | **23** | **94** | **94** | **92** | **91** | **515** | **909** | 909 |
| Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)* | **—** | **—** | **72,500** | **—** | **—** | **—** | **72,500** | 52,662 |
| Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)* | **6,090** | **4,090** | **400** | **48** | **35** | **121** | **10,784** | 19,664 |
| Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)* | **3,533** | **1,569** | **—** | **—** | **—** | **—** | **5,102** | 8,558 |
| Equity contracts *(millions of Canadian dollars)* | **20** | **34** | **—** | **—** | **—** | **—** | **54** | 55 |
| Commodity contracts - natural gas *(billions of cubic feet)* | **(33)** | **14** | **15** | **3** | **—** | **—** | **(1)** | (167) |
| Commodity contracts - crude oil *(millions of barrels)* | **28** | **—** | **—** | **—** | **—** | **—** | **28** | 4 |
| Commodity contracts - NGL *(millions of barrels)* | **2** | **—** | **—** | **—** | **—** | **—** | **2** | — |
| Commodity contracts - power *(megawatt per hour (MW/H)* | **80** | **(3)** | **(43)** | **(43)** | **(43)** | **(43)** [1] | **(16)** [2] | (7) [2] |

*1 As at December 31, 2019, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2025.*

*2 Total is an average net purchase/(sell) of power.*

**The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income**

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

| | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Amount of unrealized gain/(loss) recognized in OCI | | | |
| Cash flow hedges | | | |
| Foreign exchange contracts | **(19)** | 19 | (5) |
| Interest rate contracts | **(559)** | (190) | 6 |
| Commodity contracts | **(25)** | 2 | 11 |
| Other contracts | **10** | (3) | 1 |
| Net investment hedges | | | |
| Foreign exchange contracts | **2** | 31 | 284 |
| | **(591)** | (141) | 297 |
| Amount of (gain)/loss reclassified from AOCI to earnings | | | |
| Foreign exchange contracts[1] | **5** | 5 | (104) |
| Interest rate contracts[2,3] | **157** | 184 | 384 |
| Commodity contracts[4] | **(1)** | (1) | (9) |
| Other contracts[5] | **(3)** | 3 | 8 |
| | **158** | 191 | 279 |

*1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.*

*2 Reported within Interest expense in the Consolidated Statements of Earnings. Effective January 1, 2019, hedge ineffectiveness will no longer be measured or recorded. See Note 2.*

*3 For the year ended December 31, 2017, includes settlements of $296 million loss related to the termination of long-term interest rate swaps as not highly probable to issue long-term debt.*

*4 Reported within Transportation and other services revenue, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*

*5 Reported within Operating and administrative expenses in the Consolidated Statements of Earnings.*

We estimate that a loss of $80 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 24 months as at December 31, 2019.

**Fair Value Derivatives**

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings.

| Year ended December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Unrealized gain on derivative | **—** | 7 |
| Unrealized gain on hedged item | **—** | 1 |
| Realized loss on derivative | **—** | (8) |
| Realized loss on hedged item | **—** | (1) |

**Non-Qualifying Derivatives**

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Foreign exchange contracts[1] | **1,626** | (1,390) | 1,284 |
| Interest rate contracts[2] | **178** | 5 | 157 |
| Commodity contracts[3] | **(62)** | 485 | (199) |
| Other contracts[4] | **9** | (3) | — |
| Total unrealized derivative fair value gain/(loss), net | **1,751** | (903) | 1,242 |

*1 For the respective annual periods, reported within Transportation and other services revenue (2019 - $930 million gain; 2018 - $1,108 million loss; 2017 - $800 million gain) and Net foreign currency gain/(loss) (2019 - $696 million gain; 2018 - $282 million loss; 2017 - $484 million gain) in the Consolidated Statements of Earnings.*

*2 Reported as a decrease within Interest expense in the Consolidated Statements of Earnings.*

*3 For the respective annual periods, reported within Transportation and other services revenue (2019 - $26 million loss; 2018 - $66 million gain; 2017 - $104 million loss), Commodity sales (2019 - $544 million loss; 2018 - $599 million gain; 2017 - $90 million gain), Commodity costs (2019 - $459 million gain; 2018 - $193 million loss; 2017 - $223 million loss) and Operating and administrative expense (2019 - $49 million gain; 2018 - $13 million gain; 2017 - $38 million gain) in the Consolidated Statements of Earnings.*

*4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

**LIQUIDITY RISK**

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or United States public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2019. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

**CREDIT RISK**

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

| December 31, | 2019 | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canadian financial institutions | **146** | 28 |
| United States financial institutions | **40** | 107 |
| European financial institutions | **3** | 84 |
| Asian financial institutions | **92** | 6 |
| Other[1] | **113** | 337 |
| | **394** | 562 |

*1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.*

As at December 31, 2019, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2019 and December 31, 2018.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

**FAIR VALUE MEASUREMENTS**

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

**FAIR VALUE OF FINANCIAL INSTRUMENTS**

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

**Level 1**

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange traded derivatives used to mitigate the risk of crude oil price fluctuations.

**Level 2**
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

**Level 3**
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

We have categorized our derivative assets and liabilities measured at fair value as follows:

| December 31, 2019 | Level 1 | Level 2 | Level 3 | Total Gross Derivative Measurements |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | — | 161 | — | 161 |
| Commodity contracts | — | 33 | 130 | 163 |
| Other contracts | — | 4 | — | 4 |
| | — | 198 | 130 | 328 |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | — | 81 | — | 81 |
| Commodity contracts | — | 12 | 5 | 17 |
| Other contracts | — | 3 | — | 3 |
| | — | 96 | 5 | 101 |
| Financial liabilities | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | — | (410) | — | (410) |
| Interest rate contracts | — | (353) | — | (353) |
| Commodity contracts | (5) | (23) | (145) | (173) |
| Other contracts | — | — | — | — |
| | (5) | (786) | (145) | (936) |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | — | (934) | — | (934) |
| Interest rate contracts | — | (181) | — | (181) |
| Commodity contracts | — | (6) | (59) | (65) |
| Other contracts | — | — | — | — |
| | — | (1,121) | (59) | (1,180) |
| Total net financial asset/(liability) | | | | |
| Foreign exchange contracts | — | (1,102) | — | (1,102) |
| Interest rate contracts | — | (534) | — | (534) |
| Commodity contracts | (5) | 16 | (69) | (58) |
| Other contracts | — | 7 | — | 7 |
| | (5) | (1,613) | (69) | (1,687) |

| December 31, 2018 | Level 1 | Level 2 | Level 3 | Total Gross Derivative Instruments |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | — | 47 | — | 47 |
| Interest rate contracts | — | 22 | — | 22 |
| Commodity contracts | 24 | 45 | 360 | 429 |
| | 24 | 114 | 360 | 498 |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | — | 62 | — | 62 |
| Interest rate contracts | — | 5 | — | 5 |
| Commodity contracts | — | 30 | 22 | 52 |
| | — | 97 | 22 | 119 |
| Financial liabilities | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | — | (615) | — | (615) |
| Interest rate contracts | — | (341) | — | (341) |
| Commodity contracts | (7) | (28) | (238) | (273) |
| Other contracts | — | (5) | — | (5) |
| | (7) | (989) | (238) | (1,234) |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | — | (2,212) | — | (2,212) |
| Interest rate contracts | — | (201) | — | (201) |
| Commodity contracts | — | (23) | (155) | (178) |
| Other contracts | — | (2) | — | (2) |
| | — | (2,438) | (155) | (2,593) |
| Total net financial asset/(liability) | | | | |
| Foreign exchange contracts | — | (2,718) | — | (2,718) |
| Interest rate contracts | — | (515) | — | (515) |
| Commodity contracts | 17 | 24 | (11) | 30 |
| Other contracts | — | (7) | — | (7) |
| | 17 | (3,216) | (11) | (3,210) |

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

| **December 31, 2019** | Fair Value | Unobservable Input | Minimum Price/Volatility | Maximum Price/Volatility | Weighted Average Price/Volatility | Unit of Measurement |
|---|---|---|---|---|---|---|
| *(fair value in millions of Canadian dollars)* | | | | | | |
| Commodity contracts - financial[1] | | | | | | |
| Natural gas | **—** | **Forward gas price** | **1.95** | **4.88** | **3.04** | **$/mmbtu[2]** |
| Crude | **4** | **Forward crude price** | **44.24** | **82.29** | **52.76** | **$/barrel** |
| NGL | **3** | **Forward NGL price** | **0.54** | **0.86** | **0.82** | **$/gallon** |
| Power | **(61)** | **Forward power price** | **27.84** | **71.79** | **57.46** | **$/MW/H** |
| Commodity contracts - physical[1] | | | | | | |
| Natural gas | **28** | **Forward gas price** | **1.00** | **8.37** | **2.53** | **$/mmbtu[2]** |
| Crude | **(45)** | **Forward crude price** | **40.20** | **90.75** | **70.27** | **$/barrel** |
| NGL | **2** | **Forward NGL price** | **0.18** | **2.01** | **0.79** | **$/gallon** |
| | **(69)** | | | | | |

*1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.*

*2 One million British thermal units (mmbtu).*

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices, and for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

| Year ended December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Level 3 net derivative liability at beginning of period | **(11)** | (387) |
| Total gain/(loss) | | |
| Included in earnings[1] | **27** | 206 |
| Included in OCI | **(25)** | 2 |
| Settlements | **(60)** | 168 |
| Level 3 net derivative liability at end of period | **(69)** | (11) |

*1 Reported within Transportation and other services revenue, Commodity costs and Operating and administrative expenses in the Consolidated Statements of Earnings.*

Our policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at December 31, 2019 or 2018.

**FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS**

Our other long-term investments in other entities with no actively quoted prices are classified as Fair Value Measurement Alternative (FVMA) investments and are recorded at cost less impairment. The carrying value of FVMA and other long-term investments totaled $99 million and $102 million as at December 31, 2019 and 2018, respectively.

We have Restricted long-term investments held in trust totaling $434 million and $323 million as at December 31, 2019 and 2018, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of $580 million and $478 million as at December 31, 2019 and 2018, respectively. These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.38%. The fair value of this preferred share investment approximates its face value of $580 million as at December 31, 2019 and 2018.

As at December 31, 2019 and 2018, our long-term debt had a carrying value of $64.4 billion and $63.9 billion, respectively, before debt issuance costs and a fair value of $70.5 billion and $64.4 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2019 and 2018, the non-current notes receivable had a carrying value of $1,026 million and $767 million, respectively, which also approximates their fair value.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, restricted long-term investments and long-term debt approximate their cost due to the short period to maturity.

**NET INVESTMENT HEDGES**

We have designated a portion of our United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in United States dollar denominated investments and subsidiaries.

During the years ended December 31, 2019 and 2018, we recognized an unrealized foreign exchange gain of $317 million and a loss of $479 million, respectively, on the translation of United States dollar denominated debt and an unrealized gain on the change in fair value of our outstanding foreign exchange forward contracts of $2 million and $30 million, respectively, in OCI. During the years ended December 31, 2019 and 2018, we recognized a realized loss of nil and $45 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized loss of nil and loss of $14 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period.

## 25. INCOME TAXES

**INCOME TAX RATE RECONCILIATION**

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | **7,535** | 3,570 | 569 |
| Canadian federal statutory income tax rate | **15%** | 15% | 15 % |
| Expected federal taxes at statutory rate | **1,130** | 536 | 85 |
| Increase/(decrease) resulting from: | | | |
| Provincial and state income taxes[1] | **415** | (24) | 133 |
| Foreign and other statutory rate differentials | **129** | 94 | (601) |
| Impact of United States tax reform[2] | **—** | (2) | (2,045) |
| Effects of rate-regulated accounting[3] | **(63)** | (163) | (189) |
| Foreign allowable interest deductions[4] | **(29)** | (134) | (124) |
| Part VI.1 tax, net of federal Part I deduction[5] | **78** | 76 | 68 |
| Impairment of goodwill | **—** | 192 | 15 |
| United States BEAT tax | **67** | 43 | — |
| Non-taxable portion of gain/(loss) on sale of investment to unrelated party[6] | **—** | 31 | — |
| Valuation allowance[7] | **26** | (172) | (17) |
| Intercorporate investments[8] | **(14)** | (149) | 77 |
| Noncontrolling interests | **(13)** | (47) | (80) |
| Other | **(18)** | (44) | (19) |
| Income tax (recovery)/expense | **1,708** | 237 | (2,697) |
| Effective income tax rate | **22.7%** | 6.6% | (474.0)% |

*1 The change in provincial and state income taxes from 2018 to 2019 reflects the increase in earnings from operations and the impact of state tax rate changes in both the United States and Canada.*

*2 The amount was related to the enactment of the Tax Cuts and Jobs Act (TCJA) by the United States on December 22, 2017, which included a reduction in the federal corporate income tax rate from 35% to 21% effective for taxation years beginning after December 31, 2017.*

*3 The amount in 2019 included the federal component of the tax effect of the write-off of regulatory assets (Note 7).*

*4 The decrease in foreign allowable interest deductions in 2019 was due to changes in the related loan portfolio and tax legislative changes in Canada, the United States, and Europe.*

*5 Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.*

*6 The amount represents the federal component of the non-taxable portion of the gain on the sales of the Canadian Natural Gas Gathering and Processing Businesses in 2018.*

*7 The increase in 2018 is due to the federal component of the tax effect of a valuation allowance on the deferred tax assets related to an outside basis temporary difference that, in 2018, was more likely than not to be realized.*

*8 The amount relates to the federal component of changes in assertions regarding the manner of recovery of intercorporate investments such that deferred tax related to outside basis temporary differences was required to be recorded for MATL (Note 8), Renewable Assets in 2018 and for EIPLP in 2017.*

**COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES**

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings/(loss) before income taxes | | | |
| Canada | **3,560** | 118 | 2,200 |
| United States | **3,115** | 2,582 | (2,431) |
| Other | **860** | 870 | 800 |
| | **7,535** | 3,570 | 569 |
| Current income taxes | | | |
| Canada | **347** | 311 | 129 |
| United States | **107** | 66 | 46 |
| Other | **98** | 8 | 5 |
| | **552** | 385 | 180 |
| Deferred income taxes | | | |
| Canada | **490** | (598) | 299 |
| United States | **672** | 439 | (3,160) |
| Other | **(6)** | 11 | (16) |
| | **1,156** | (148) | (2,877) |
| Income tax (recovery)/expense | **1,708** | 237 | (2,697) |

**COMPONENTS OF DEFERRED INCOME TAXES**

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

| December 31, | **2019** | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Deferred income tax liabilities | | |
| Property, plant and equipment | **(7,290)** | (7,018) |
| Investments | **(4,620)** | (4,441) |
| Regulatory assets | **(1,052)** | (756) |
| Other | **(40)** | (192) |
| Total deferred income tax liabilities | **(13,002)** | (12,407) |
| Deferred income tax assets | | |
| Financial instruments | **679** | 1,103 |
| Pension and OPEB plans | **206** | 181 |
| Loss carryforwards | **1,693** | 1,820 |
| Other | **1,641** | 1,274 |
| Total deferred income tax assets | **4,219** | 4,378 |
| Less valuation allowance | **(84)** | (51) |
| Total deferred income tax assets, net | **4,135** | 4,327 |
| Net deferred income tax liabilities | **(8,867)** | (8,080) |
| Presented as follows: | | |
| Total deferred income tax assets | **1,000** | 1,374 |
| Total deferred income tax liabilities | **(9,867)** | (9,454) |
| Net deferred income tax liabilities | **(8,867)** | (8,080) |

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2019 and 2018, we recognized the benefit of unused tax loss carryforwards of $3.2 billion and $3.4 billion, respectively, in Canada which expire in 2026 and beyond.

As at December 31, 2019 and 2018, we recognized the benefit of unused tax loss carryforwards of $3.6 billion and $3.4 billion, respectively, in the United States which expire in 2023 and beyond.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $5.3 billion and $5.8 billion for the period December 31, 2019 and 2018, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the United States (Federal) and Canada (Federal, Alberta and Ontario). We are open to examination by Canadian tax authorities for the 2010 to 2019 tax years and by United States tax authorities for the 2015 to 2019 tax years. We are currently under examination for income tax matters in Canada for the 2013 to 2017 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

**United States Tax Reform**

On December 22, 2017, the United States enacted the TCJA. As a result of the TCJA we recorded $67 million and $43 million in tax expense for the years ended December 31, 2019 and 2018, respectively in connection with the Base erosion and Anti-abuse tax (BEAT). We recorded no provisions for the Global Intangible Low Taxed Income Tax (GILTI).

Most changes to the TCJA are effective for taxation years beginning after December 31, 2017. While the changes are broad and complex, the most significant change was the reduction in the corporate federal income tax rate from 35% to 21%. In 2017 we were also impacted by a one-time deemed repatriation or “toll” tax on undistributed earnings and profits of United States controlled foreign affiliates, including Canadian subsidiaries.

During the first quarter of 2018 we refined our calculation of the regulatory liability associated with the TCJA which resulted in a $30 million reduction to the overall regulatory liability. An additional reduction to the regulated liability in the amount of $223 million was recorded in the fourth quarter of 2018 in connection with rate cases filed that eliminated a portion of regulated liability formerly included in SEP's rate base.

In 2017 we made reasonable estimates for the measurement and accounting of certain effects of the TCJA in accordance with SEC Staff Accounting Bulletin No.118 (SAB 118). Accordingly, we recorded a $34 million increase to our 2017 current income tax provision related to the toll tax, payable over eight years. We recorded a $2.0 billion decrease to our 2017 deferred income tax provision related to the reduction in the corporate federal income tax rate. The accounting for these items decreased our accumulated deferred income tax liability by $3.1 billion and increased our regulatory liability by $1.1 billion in 2017. We have also adjusted our valuation allowance for certain deferred tax assets existing at December 31, 2016 for the reduction in the corporate federal income tax rate by $0.2 billion. We have recognized these tax impacts and included these amounts in our consolidated financial statements for the year ended December 31, 2017.

**UNRECOGNIZED TAX BENEFITS**

| Year ended December 31, | 2019 | 2018 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Unrecognized tax benefits at beginning of year | **139** | 150 |
| Gross increases for tax positions of current year | **1** | 2 |
| Gross decreases for tax positions of prior year | **(1)** | (12) |
| Change in translation of foreign currency | **(4)** | 3 |
| Lapses of statute of limitations | **(6)** | (3) |
| Settlements | **—** | (1) |
| Unrecognized tax benefits at end of year | **129** | 139 |

The unrecognized tax benefits as at December 31, 2019, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2019 and 2018 were $3 million expense and $5 million expense, respectively, of interest and penalties. As at December 31, 2019 and 2018, interest and penalties of $15 million and $12 million, respectively, have been accrued.

## 26. PENSION AND OTHER POSTRETIREMENT BENEFITS

**PENSION PLANS**

We sponsor Canadian and United States contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian Plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The United States Plans provide defined benefit pension benefits to our United States employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the United States.

**Defined Benefit Pension Plan Benefits**

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

**Defined Contribution Pension Plan Benefits**

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

**Benefit Obligations, Plan Assets and Funded Status**

The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension plans:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation at beginning of year | **3,997** | 4,033 | **1,214** | 1,279 |
| Service cost | **149** | 149 | **45** | 45 |
| Interest cost | **139** | 130 | **41** | 38 |
| Participant contributions | **32** | 25 | **—** | — |
| Actuarial (gain)/loss | **423** | (146) | **106** | (103) |
| Benefits paid | **(187)** | (184) | **(101)** | (60) |
| Plan settlements[1] | **(99)** | — | **(1)** | (65) |
| Transfers out | **(8)** | (10) | **(6)** | — |
| Foreign currency exchange rate changes | **—** | — | **(63)** | 105 |
| Other | **—** | — | **(5)** | (25) |
| Projected benefit obligation at end of year[2] | **4,446** | 3,997 | **1,230** | 1,214 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | **3,523** | 3,619 | **1,045** | 1,097 |
| Actual return/(loss) on plan assets | **448** | (42) | **176** | (48) |
| Employer contributions | **114** | 113 | **46** | 40 |
| Participant contributions | **32** | 25 | **—** | — |
| Benefits paid | **(187)** | (184) | **(101)** | (60) |
| Plan settlements[1] | **(99)** | — | **(1)** | (65) |
| Transfers out | **(4)** | (8) | **—** | — |
| Foreign currency exchange rate changes | **—** | — | **(56)** | 91 |
| Other | **—** | — | **(5)** | (10) |
| Fair value of plan assets at end of year[3] | **3,827** | 3,523 | **1,104** | 1,045 |
| Underfunded status at end of year | **(619)** | (474) | **(126)** | (169) |
| Presented as follows: | | | | |
| Deferred amounts and other assets | **35** | 29 | **—** | — |
| Accounts payable and other | **(9)** | (9) | **(4)** | (4) |
| Other long-term liabilities | **(645)** | (494) | **(122)** | (165) |
| | **(619)** | (474) | **(126)** | (169) |

*1 Plan settlements for the Canadian Plans are related to the disposition of our federally regulated BC Field Services business.*

*2 The accumulated benefit obligation for our Canadian pension plans was $4.0 billion and $3.7 billion as at December 31, 2019 and 2018, respectively. The accumulated benefit obligation for our United States pension plans was $1.2 billion as at December 31, 2019 and 2018.*

*3 Assets in the amount of $10 million (2018 - $7 million) and $51 million (2018 - $39 million), related to our Canadian and United States non-registered supplemental pension plan obligations, are held in Grantor Trusts and Rabbi Trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.*

Certain of our pension plans have an accumulated benefit obligation in excess of the fair value of plan assets. For these plans, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| Projected benefit obligation | **1,481** | 1,422 | **103** | 1,214 |
| Accumulated benefit obligation | **1,361** | 1,299 | **98** | 1,179 |
| Fair value of plan assets | **1,087** | 1,064 | **—** | 1,045 |

**Amount Recognized in Accumulated Other Comprehensive Income**

The amount of pre-tax AOCI relating to our pension plans are as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| Net actuarial loss | **445** | 435 | **134** | 133 |
| Prior service credit | **—** | — | **(2)** | (3) |
| Total amount recognized in AOCI[1] | **445** | 435 | **132** | 130 |

*1 Excludes amounts related to cumulative translation adjustment.*

**Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income**

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| *(millions of Canadian dollars)* | | | | | | |
| Service cost | **149** | 149 | 156 | **45** | 45 | 48 |
| Interest cost | **139** | 130 | 116 | **41** | 38 | 35 |
| Expected return on plan assets | **(245)** | (245) | (201) | **(78)** | (88) | (57) |
| Amortization/settlement of net actuarial loss | **41** | 25 | 29 | **2** | 7 | 10 |
| Amortization/curtailment of prior service (credit)/ cost | **—** | — | — | **(1)** | 3 | — |
| Net periodic benefit cost | **84** | 59 | 100 | **9** | 5 | 36 |
| Defined contribution benefit cost | **8** | 11 | 11 | **—** | — | — |
| Net pension cost recognized in Earnings | **92** | 70 | 111 | **9** | 5 | 36 |
| Amount recognized in OCI: | | | | | | |
| Effect of plan combination | **—** | — | — | **(6)** | — | — |
| Amortization/settlement of net actuarial loss | **(26)** | (11) | (14) | **(2)** | (7) | (9) |
| Amortization/curtailment of prior service credit/ (cost) | **—** | — | — | **1** | (3) | — |
| Net actuarial loss arising during the year | **115** | 112 | 38 | **8** | 28 | — |
| Total amount recognized in OCI | **89** | 101 | 24 | **1** | 18 | (9) |
| Total amount recognized in Comprehensive income | **181** | 171 | 135 | **10** | 23 | 27 |

We estimate that approximately $21 million related to the Canadian pension plans and nil related to the United States pension plans as at December 31, 2019 will be reclassified from AOCI into Earnings in the next 12 months.

**Actuarial Assumptions**

The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| **Projected benefit obligation** | | | | | | |
| Discount rate | **3.0%** | 3.8% | 3.6% | **3.0%** | 3.9% | 3.5% |
| Rate of salary increase | **3.2%** | 3.2% | 3.2% | **2.9%** | 2.8% | 3.1% |
| **Net periodic benefit cost** | | | | | | |
| Discount rate | **3.8%** | 3.6% | 4.0% | **3.9%** | 3.4% | 4.0% |
| Expected rate of return on plan assets | **7.0%** | 6.8% | 6.5% | **8.0%** | 7.4% | 7.2% |
| Rate of salary increase | **3.2%** | 3.2% | 3.7% | **2.9%** | 2.9% | 3.3% |

**OTHER POSTRETIREMENT BENEFIT PLANS**

We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

**Benefit Obligations, Plan Assets and Funded Status**

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| **Change in accumulated postretirement benefit obligation** | | | | |
| Accumulated postretirement benefit obligation at beginning of year | **282** | 321 | **305** | 337 |
| Service cost | **5** | 8 | **2** | 3 |
| Interest cost | **10** | 10 | **10** | 10 |
| Participant contributions | **—** | — | **5** | 6 |
| Actuarial (gain)/loss | **15** | (45) | **7** | (25) |
| Benefits paid | **(6)** | (11) | **(28)** | (29) |
| Plan amendments | **—** | — | **—** | (8) |
| Foreign currency exchange rate changes | **—** | — | **(15)** | 27 |
| Other | **(13)** | (1) | **2** | (16) |
| Accumulated postretirement benefit obligation at end of year | **293** | 282 | **288** | 305 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | **—** | — | **181** | 213 |
| Actual return/(loss) on plan assets | **—** | — | **27** | (13) |
| Employer contributions | **6** | 11 | **10** | 8 |
| Participant contributions | **—** | — | **5** | 6 |
| Benefits paid | **(6)** | (11) | **(28)** | (29) |
| Foreign currency exchange rate changes | **—** | — | **(9)** | 16 |
| Other | **—** | — | **2** | (20) |
| Fair value of plan assets at end of year | **—** | — | **188** | 181 |
| Underfunded status at end of year | **(293)** | (282) | **(100)** | (124) |
| Presented as follows: | | | | |
| Deferred amounts and other assets | **—** | — | **—** | 2 |
| Accounts payable and other | **(12)** | (12) | **(8)** | (7) |
| Other long-term liabilities | **(281)** | (270) | **(92)** | (119) |
| | **(293)** | (282) | **(100)** | (124) |

**Amount Recognized in Accumulated Other Comprehensive Income**
The amount of pre-tax AOCI relating to our OPEB plans are as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| Net actuarial gain | **(7)** | (29) | **(23)** | (15) |
| Prior service credit | **(1)** | (2) | **(13)** | (15) |
| Total amount recognized in AOCI[1] | **(8)** | (31) | **(36)** | (30) |

*1 Excludes amounts related to cumulative translation adjustment.*

**Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income**
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| *(millions of Canadian dollars)* | | | | | | |
| Service cost | **5** | 8 | 7 | **2** | 3 | 5 |
| Interest cost | **10** | 10 | 10 | **10** | 10 | 10 |
| Expected return on plan assets | **—** | — | — | **(12)** | (12) | (10) |
| Amortization/settlement of net actuarial gain | **(7)** | — | — | **—** | (1) | — |
| Amortization/curtailment of prior service (credit)/ cost | **(1)** | — | 1 | **(2)** | (4) | — |
| Net periodic benefit cost recognized in Earnings | **7** | 18 | 18 | **(2)** | (4) | 5 |
| Amount recognized in OCI: | | | | | | |
| Amortization/settlement of net actuarial gain/ (loss) | **7** | — | (1) | **—** | 1 | 1 |
| Amortization/curtailment of prior service credit | **1** | — | — | **2** | 4 | — |
| Net actuarial (gain)/loss arising during the year | **15** | (46) | (8) | **(8)** | (1) | (42) |
| Prior service (credit)/cost | **—** | — | (3) | **—** | (8) | 1 |
| Total amount recognized in OCI | **23** | (46) | (12) | **(6)** | (4) | (40) |
| Total amount recognized in Comprehensive income | **30** | (28) | 6 | **(8)** | (8) | (35) |

We estimate that approximately $1 million related to the Canadian OPEB plans and $3 million related to the United States OPEB plans as at December 31, 2019 will be reclassified from AOCI into earnings in the next 12 months.

**Actuarial Assumptions**
The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| | **2019** | 2018 | 2017 | **2019** | 2018 | 2017 |
| **Accumulated postretirement benefit obligation** | | | | | | |
| Discount rate | **3.1%** | 3.8% | 3.6% | **2.8%** | 4.0% | 3.5% |
| **Net periodic benefit cost** | | | | | | |
| Discount rate | **3.8%** | 3.6% | 4.0% | **4.0%** | 3.3% | 4.0% |
| Rate of return on plan assets | **N/A** | N/A | N/A | **6.7%** | 5.7% | 6.0% |

**Assumed Health Care Cost Trend Rates**

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Health care cost trend rate assumed for next year | **4.0%** | 5.6% | **7.2%** | 7.4% |
| Rate to which the cost trend is assumed to decline (ultimate trend rate) | **4.0%** | 4.4% | **4.5%** | 4.5% |
| Year that the rate reaches the ultimate trend rate | **N/A** | 2034 | **2037** | 2037 |

A 1% change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2019:

| | Canada | | United States | |
|---|---|---|---|---|
| | 1% Increase | 1% Decrease | 1% Increase | 1% Decrease |
| *(millions of Canadian dollars)* | | | | |
| Total service and interest costs | **1** | **(1)** | **1** | **(1)** |
| Accumulated postretirement benefit obligation | **21** | **(17)** | **19** | **(17)** |

**PLAN ASSETS**

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| | **Target** | December 31, | | **Target** | December 31, | |
| **Asset Category** | **Allocation** | **2019** | 2018 | **Allocation** | **2019** | 2018 |
| Equity securities | **43.4%** | **46.4%** | 45.8% | **45.0%** | **55.2%** | 52.7% |
| Fixed income securities | **30.3%** | **31.0%** | 38.8% | **20.0%** | **19.8%** | 34.9% |
| Alternatives[1] | **26.3%** | **22.6%** | 15.4% | **35.0%** | **25.0%** | 12.4% |

*1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.*

**Pension Plans**

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

| | Canada | | | | United States | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1[1] | Level 2[2] | Level 3[3] | Total | Level 1[1] | Level 2[2] | Level 3[3] | Total |
| *(millions of Canadian dollars)* | | | | | | | | |
| **December 31, 2019** | | | | | | | | |
| Cash and cash equivalents | **184** | **—** | **—** | **184** | **14** | **—** | **—** | **14** |
| Equity securities | | | | | | | | |
| Canada | **165** | **183** | **—** | **348** | **—** | **—** | **—** | **—** |
| United States | **—** | **—** | **—** | **—** | **—** | **93** | **—** | **93** |
| Global | **—** | **1,429** | **—** | **1,429** | **—** | **516** | **—** | **516** |
| Fixed income securities | | | | | | | | |
| Government | **196** | **418** | **—** | **614** | **—** | **164** | **—** | **164** |
| Corporate | **—** | **388** | **—** | **388** | **—** | **41** | **—** | **41** |
| Alternatives[4] | **—** | **—** | **852** | **852** | **—** | **—** | **276** | **276** |
| Forward currency contracts | **—** | **12** | **—** | **12** | **—** | **—** | **—** | **—** |
| Total pension plan assets at fair value | **545** | **2,430** | **852** | **3,827** | **14** | **814** | **276** | **1,104** |
| **December 31, 2018** | | | | | | | | |
| Cash and cash equivalents | 240 | — | — | 240 | 56 | — | — | 56 |
| Equity securities | | | | | | | | |
| Canada | 138 | 481 | — | 619 | — | — | — | — |
| United States | — | — | — | — | — | 110 | — | 110 |
| Global | — | 992 | — | 992 | — | 440 | — | 440 |
| Fixed income securities | | | | | | | | |
| Government | 218 | 453 | — | 671 | — | 265 | — | 265 |
| Corporate | — | 457 | — | 457 | — | 44 | — | 44 |
| Alternatives[4] | — | — | 562 | 562 | — | — | 130 | 130 |
| Forward currency contracts | — | (18) | — | (18) | — | — | — | — |
| Total pension plan assets at fair value | 596 | 2,365 | 562 | 3,523 | 56 | 859 | 130 | 1,045 |

*1 Level 1 assets include assets with quoted prices in active markets for identical assets.*
*2 Level 2 assets include assets with significant observable inputs.*
*3 Level 3 assets include assets with significant unobservable inputs.*
*4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.*

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| Balance at beginning of year | **562** | 340 | **130** | 56 |
| Unrealized and realized gains | **10** | 77 | **13** | 9 |
| Purchases and settlements, net | **280** | 145 | **133** | 65 |
| Balance at end of year | **852** | 562 | **276** | 130 |

**OPEB Plans**

The following table summarizes the fair value of plan assets for our OPEB plans recorded at each fair value hierarchy level:

| | Canada | | | | United States | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1[1] | Level 2[2] | Level 3[3] | Total | Level 1[1] | Level 2[2] | Level 3[3] | Total |
| *(millions of Canadian dollars)* | | | | | | | | |
| **December 31, 2019** | | | | | | | | |
| Cash and cash equivalents | **—** | **—** | **—** | **—** | **2** | **—** | **—** | **2** |
| Equity securities | | | | | | | | |
| United States | **—** | **—** | **—** | **—** | **—** | **75** | **—** | **75** |
| Global | **—** | **—** | **—** | **—** | **—** | **38** | **—** | **38** |
| Fixed income securities | | | | | | | | |
| Government | **—** | **—** | **—** | **—** | **40** | **15** | **—** | **55** |
| Alternatives[4] | **—** | **—** | **—** | **—** | **—** | **—** | **18** | **18** |
| Total OPEB plan assets at fair value | **—** | **—** | **—** | **—** | **42** | **128** | **18** | **188** |
| **December 31, 2018** | | | | | | | | |
| Cash and cash equivalents | — | — | — | — | 7 | — | — | 7 |
| Equity securities | | | | | | | | |
| United States | — | — | — | — | — | 68 | — | 68 |
| Global | — | — | — | — | — | 30 | — | 30 |
| Fixed income securities | | | | | | | | |
| Government | — | — | — | — | 43 | 28 | — | 71 |
| Corporate | — | — | — | — | — | — | — | — |
| Alternatives[4] | — | — | — | — | — | — | 5 | 5 |
| Total OPEB plan assets at fair value | — | — | — | — | 50 | 126 | 5 | 181 |

*1 Level 1 assets include assets with quoted prices in active markets for identical assets.*
*2 Level 2 assets include assets with significant observable inputs.*
*3 Level 3 assets include assets with significant unobservable inputs.*
*4 Alternatives includes investments in private debt, private equity, infrastructure and real estate.*

Changes in the net fair value of OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

| | Canada | | United States | |
|---|---|---|---|---|
| December 31, | **2019** | 2018 | **2019** | 2018 |
| *(millions of Canadian dollars)* | | | | |
| Balance at beginning of year | **—** | — | **5** | — |
| Unrealized and realized gains | **—** | — | **1** | — |
| Purchases and settlements, net | **—** | — | **12** | 5 |
| Balance at end of year | **—** | — | **18** | 5 |

**EXPECTED BENEFIT PAYMENTS**

| Year ending December 31, | 2020 | 2021 | 2022 | 2023 | 2024 | 2025-2029 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Pension** | | | | | | |
| Canada | 180 | 186 | 192 | 198 | 204 | 1,105 |
| United States | 87 | 90 | 91 | 89 | 91 | 402 |
| **OPEB** | | | | | | |
| Canada | 12 | 12 | 12 | 13 | 13 | 69 |
| United States | 23 | 22 | 21 | 20 | 19 | 82 |

**EXPECTED EMPLOYER CONTRIBUTIONS**

In 2020, we expect to contribute approximately $104 million and $31 million to the Canadian and United States pension plans, respectively, and $12 million and $8 million to the Canadian and United States OPEB plans, respectively.

**RETIREMENT SAVINGS PLANS**

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to both Canadian and United States employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions up to 2.5% and 6.0% of eligible pay per pay period for Canadian and United States employees, respectively. For the years ended December 31, 2019, 2018 and 2017, pre-tax employer matching contribution costs were $4 million, $13 million and $14 million for Canadian employees and $27 million, $27 million and $31 million for United States employees, respectively.

## 27. LEASES

**LESSEE**

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 3 months to 28 years.

For the year ended December 31, 2019, we incurred operating lease expenses of $113 million. Operating lease expenses are reported under Operating and administrative expenses on the Consolidated Statements of Earnings.

For the year ended December 31, 2019, operating lease payments to settle lease liabilities were $123 million. Operating lease payments are reported under operating activities in the Consolidated Statements of Cash Flows.

**Supplemental Statements of Financial Position Information**

| *(millions of Canadian dollars, except lease term and discount rate)* | **December 31, 2019** | January 1, 2019 |
|---|---|---|
| **Operating leases** | | |
| Operating lease right-of-use assets, net[1] | **713** | 771 |
| Operating lease liabilities - current[2] | **94** | 86 |
| Operating lease liabilities - long-term[3] | **689** | 770 |
| Total operating lease liabilities | **783** | 856 |
| **Weighted average remaining lease term** | | |
| Operating leases | **13 years** | 14 years |
| **Weighted average discount rate** | | |
| Operating leases | **4.3%** | 4.3% |

1 *Right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.*
2 *Current lease liabilities are reported under Accounts payable and other in the Consolidated Statements of Financial Position.*
3 *Long-term lease liabilities are reported under Other long-term liabilities in the Consolidated Statements of Financial Position.*

As at December 31, 2019, our operating lease liabilities are expected to mature as follows:

| *(millions of Canadian dollars)* | Operating leases |
|---|---|
| 2020 | 128 |
| 2021 | 99 |
| 2022 | 94 |
| 2023 | 84 |
| 2024 | 79 |
| Thereafter | 588 |
| Total undiscounted lease payments | 1,072 |
| Less imputed interest | (289) |
| Total operating lease liabilities | 783 |

**LESSOR**

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 2 months to 24 years.

| **Year ended December 31,** | **2019** |
|---|---|
| *(millions of Canadian dollars)* | |
| Operating lease income | **265** |
| Variable lease income | **360** |
| Total lease income[1] | **625** |

1 *Lease income is recorded under Transportation and other services in the Consolidated Statements of Earnings.*

As at December 31, 2019, the following table sets out future lease payments to be received under operating lease contracts where we are the lessor:

| *(millions of Canadian dollars)* | Operating leases |
|---|---|
| 2020 | 236 |
| 2021 | 199 |
| 2022 | 188 |
| 2023 | 180 |
| 2024 | 178 |
| Thereafter | 2,276 |
| Future lease payments | 3,257 |

## 28. CHANGES IN OPERATING ASSETS AND LIABILITIES

| Year ended December 31, | **2019** | 2018 | 2017 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Accounts receivable and other | **(659)** | 857 | (783) |
| Accounts receivable from affiliates | **6** | 54 | 24 |
| Inventory | **(24)** | 164 | (289) |
| Deferred amounts and other assets | **133** | 226 | (138) |
| Accounts payable and other | **175** | (151) | 277 |
| Accounts payable to affiliates | **(24)** | (122) | (62) |
| Interest payable | **(41)** | 25 | 124 |
| Other long-term liabilities | **175** | (138) | 509 |
| | **(259)** | 915 | (338) |

# 29. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

**SERVICE AGREEMENTS**
Vector, a joint venture, contracts our services to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million, $7 million and $14 million for the years ended December 31, 2019, 2018 and 2017, respectively.

**TRANSPORTATION AGREEMENTS**
Certain wholly-owned subsidiaries within the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage and Energy Services segments have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to us for transportation services for the years ended December 31, 2019, 2018 and 2017 were $812 million, $572 million and $721 million, respectively.

**AFFILIATE REVENUES AND PURCHASES**
Certain wholly-owned subsidiaries within the Energy Services segments made natural gas and NGL purchases of $392 million, $322 million and $142 million from several joint venture affiliates during the years ended December 31, 2019, 2018 and 2017, respectively.

In addition to this, Enbridge recorded transportation and natural gas sales of $145 million, $122 million and $60 million within the Energy Services and Gas Distribution and Storage segments to equity investment affiliates during the years ended December 31, 2019, 2018 and 2017, respectively.

DCP Midstream processes certain of our pipeline customers' gas to meet gas quality specifications in order to be transported on our system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $34 million (US$26 million), $52 million (US$40 million) and $47 million (US$36 million) during the years ended December 31, 2019, 2018 and 2017, respectively, from DCP Midstream related to those sales.

In addition to the above, we recorded other revenues from several joint venture affiliates related to the transportation and storage of natural gas of $69 million (US$52 million), $14 million (US$11 million) and $4 million (US$3 million) during the years ended December 31, 2019, 2018 and 2017, respectively.

In the ordinary course of business, we are reimbursed by joint venture partners for operating and maintenance expenses for certain projects. We received reimbursements from these joint ventures of $48 million (US$36 million), $28 million (US$22 million) and $10 million (US$8 million) during the years ended December 31, 2019, 2018 and 2017, respectively.

**LONG-TERM NOTES RECEIVABLE FROM AFFILIATES**
As at December 31, 2019, amounts receivable from affiliates include a series of loans totaling $1,023 million ($769 million as at December 31, 2018), which require quarterly interest payments at annual interest rates ranging from 3% to 8%. These amounts are included in deferred amounts and other assets in the Consolidated Statements of Financial position.

# 30. COMMITMENTS AND CONTINGENCIES

**COMMITMENTS**

At December 31, 2019, we have commitments as detailed below:

| | Total | Less than 1 year | 2 years | 3 years | 4 years | 5 years | Thereafter |
|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | |
| Annual debt maturities[1] | 63,585 | 4,394 | 6,856 | 4,054 | 2,585 | 7,712 | 37,984 |
| Interest obligations[2] | 29,498 | 2,416 | 2,296 | 2,216 | 2,076 | 1,915 | 18,579 |
| Purchase of services, pipe and other materials, including transportation[3,4] | 9,448 | 2,891 | 1,507 | 1,217 | 564 | 570 | 2,699 |
| Maintenance agreements | 435 | 56 | 55 | 53 | 25 | 20 | 226 |
| Land lease commitments | 1,190 | 30 | 35 | 35 | 35 | 36 | 1,019 |
| Total | 104,156 | 9,787 | 10,749 | 7,575 | 5,285 | 10,253 | 60,507 |

*1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discount, debt issue costs and finance lease obligations. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

*2 Includes debentures and term notes bearing interest at fixed, floating and fixed-to-floating rates.*

*3 Includes capital and operating commitments.*

*4 Consists primarily of gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.*

**ENVIRONMENTAL**

We are subject to various Canadian and US federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and our affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with the operating activities of our liquids and natural gas businesses.

**AUX SABLE**

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim.

On November 27, 2019, the counterparty filed an amended amended claim providing further particulars of its claim against Aux Sable, increasing its damages claimed, and adding defendants Aux Sable Liquid Products Inc. and Aux Sable Extraction LLC (general partners of the previously existing defendants). Aux Sable filed an amended Statement of Defence responding to the amended amended claim on January 31, 2020.

While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

**TAX MATTERS**

We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

**OTHER LITIGATION**

We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

## 31. GUARANTEES

In the normal course of conducting business, we enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed affiliate entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases. We typically enter into these arrangements to facilitate commercial transactions with third parties.

Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2019 guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources. Please refer to *Note 12 - Variable Interest Entities* for further discussion regarding specific guarantees related to unconsolidated VIEs.

## 32. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, the Partnerships, pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes, and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

**Consenting SEP notes and EEP notes under Guarantee**

| SEP Notes[1] | EEP Notes[2] |
|---|---|
| Floating Rate Senior Notes due 2020 | 4.200% Notes due 2021 |
| 4.600% Senior Notes due 2021 | 5.875% Notes due 2025 |
| 4.750% Senior Notes due 2024 | 5.950% Notes due 2033 |
| 3.500% Senior Notes due 2025 | 6.300% Notes due 2034 |
| 3.375% Senior Notes due 2026 | 7.500% Notes due 2038 |
| 5.950% Senior Notes due 2043 | 5.500% Notes due 2040 |
| 4.500% Senior Notes due 2045 | 7.375% Notes due 2045 |

1 *As at December 31, 2019, the aggregate outstanding principal amount of SEP notes was approximately US$3.9 billion.*
2 *As at December 31, 2019, the aggregate outstanding principal amount of EEP notes was approximately US$3.0 billion.*

**Enbridge Notes under Guarantees**

| USD Denominated[1] | CAD Denominated[2] |
|---|---|
| Senior Floating Rate Notes due 2020 | 4.530% Senior Notes due 2020 |
| Senior Floating Rate Notes due 2020 | 4.850% Senior Notes due 2020 |
| 2.900% Senior Notes due 2022 | 4.260% Senior Notes due 2021 |
| 4.000% Senior Notes due 2023 | 3.160% Senior Notes due 2021 |
| 3.500% Senior Notes due 2024 | 4.850% Senior Notes due 2022 |
| 2.500% Senior Notes due 2025 | 3.190% Senior Notes due 2022 |
| 4.250% Senior Notes due 2026 | 3.940% Senior Notes due 2023 |
| 3.700% Senior Notes due 2027 | 3.940% Senior Notes due 2023 |
| 3.125% Senior Notes due 2029 | 3.950% Senior Notes due 2024 |
| 4.500% Senior Notes due 2044 | 3.200% Senior Notes due 2027 |
| 5.500% Senior Notes due 2046 | 6.100% Senior Notes due 2028 |
| 4.000% Senior Notes due 2049 | 2.990% Senior Notes due 2029 |
| | 7.220% Senior Notes due 2030 |
| | 7.200% Senior Notes due 2032 |
| | 5.570% Senior Notes due 2035 |
| | 5.750% Senior Notes due 2039 |
| | 5.120% Senior Notes due 2040 |
| | 4.240% Senior Notes due 2042 |
| | 4.570% Senior Notes due 2044 |
| | 4.870% Senior Notes due 2044 |
| | 4.560% Senior Notes due 2064 |

1 *As at December 31, 2019, the aggregate outstanding principal amount of the Enbridge United States dollar denominated notes was approximately US$7.9 billion.*

2 *As at December 31, 2019, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $7.6 billion.*

In accordance with Rule 3-10 of the United States Securities and Exchange Commission's Regulation S-X, which provides an exemption from the reporting requirements of the Securities Exchange Act of 1934 for subsidiary issuers of guaranteed securities and subsidiary guarantors, in lieu of filing separate financial statements for each of the Partnerships, we have included the accompanying condensed consolidating financial information with separate columns representing the following:

1. Enbridge Inc., the Parent Issuer and Guarantor;
2. SEP, a Subsidiary Issuer and Guarantor;
3. EEP, a Subsidiary Issuer and Guarantor;
4. Subsidiary Non-Guarantors, as defined herein;
5. Consolidating and elimination entries required to consolidate the Parent Issuer and Guarantor and its subsidiaries, including the Subsidiary Issuers and Guarantors, and
6. Enbridge Inc. and subsidiaries on a consolidated basis.

For the purposes of the condensed consolidating financial information only, investments in subsidiaries are accounted for under the equity method. In addition, the Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities. These intercompany investments and related activities eliminate on consolidation and are presented separately only for the purpose of the accompanying Condensed Consolidating Statements.

**Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2019**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Operating revenues | | | | | | |
| Commodity sales | — | — | — | 29,309 | — | **29,309** |
| Gas distribution sales | — | — | — | 4,205 | — | **4,205** |
| Transportation and other services | — | — | — | 16,555 | — | **16,555** |
| Total operating revenues | — | — | — | 50,069 | — | **50,069** |
| Operating Expenses | | | | | | |
| Commodity costs | — | — | — | 28,802 | — | **28,802** |
| Gas distribution costs | — | — | — | 2,202 | — | **2,202** |
| Operating and administrative | 128 | 5 | (16) | 6,874 | — | **6,991** |
| Depreciation and amortization | 67 | — | — | 3,324 | — | **3,391** |
| Impairment of long-lived assets | — | — | — | 423 | — | **423** |
| Impairment of goodwill | — | — | — | — | — | **—** |
| Total operating expenses | 195 | 5 | (16) | 41,625 | — | **41,809** |
| Operating income/(loss) | (195) | (5) | 16 | 8,444 | — | **8,260** |
| Income from equity investments | 70 | 133 | — | 1,366 | (66) | **1,503** |
| Equity earnings from consolidated subsidiaries | 3,881 | 1,189 | 1,043 | 1,696 | (7,809) | **—** |
| Other | — | — | — | — | — | **—** |
| Net foreign currency gain/(loss) | 1,671 | — | — | (106) | (1,088) | **477** |
| Gain/(loss) on dispositions | (7) | — | — | (293) | — | **(300)** |
| Other, including other income from affiliates | 1,944 | 2 | 189 | 573 | (2,450) | **258** |
| Interest expense | (1,268) | (330) | (591) | (2,966) | 2,492 | **(2,663)** |
| Earnings before income taxes | 6,096 | 989 | 657 | 8,714 | (8,921) | **7,535** |
| Income tax (expense)/recovery | (391) | 44 | 6 | (1,985) | 618 | **(1,708)** |
| Earnings | 5,705 | 1,033 | 663 | 6,729 | (8,303) | **5,827** |
| Earnings attributable to noncontrolling interests and redeemable noncontrolling interests | — | — | — | — | (122) | **(122)** |
| Earnings attributable to controlling interests | 5,705 | 1,033 | 663 | 6,729 | (8,425) | **5,705** |
| Preference share dividends | (383) | — | — | — | — | **(383)** |
| Earnings attributable to common shareholders | 5,322 | 1,033 | 663 | 6,729 | (8,425) | **5,322** |
| Earnings | 5,705 | 1,033 | 663 | 6,729 | (8,303) | **5,827** |
| Total other comprehensive income/ (loss) | (2,992) | (67) | 51 | (929) | 830 | **(3,107)** |
| Comprehensive income | 2,713 | 966 | 714 | 5,800 | (7,473) | **2,720** |
| Comprehensive income attributable to noncontrolling interests | — | — | — | — | (7) | **(7)** |
| Comprehensive income attributable to controlling interests | 2,713 | 966 | 714 | 5,800 | (7,480) | **2,713** |

**Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2018**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Operating revenues | | | | | | |
| Commodity sales | — | — | — | 27,660 | — | 27,660 |
| Gas distribution sales | — | — | — | 4,360 | — | 4,360 |
| Transportation and other services | — | — | — | 14,358 | — | 14,358 |
| Total operating revenues | — | — | — | 46,378 | — | 46,378 |
| Operating Expenses | | | | | | |
| Commodity costs | — | — | — | 26,818 | — | 26,818 |
| Gas distribution costs | — | — | — | 2,583 | — | 2,583 |
| Operating and administrative | 180 | 14 | 54 | 6,622 | (78) | 6,792 |
| Depreciation and amortization | 59 | — | — | 3,187 | — | 3,246 |
| Impairment of long-lived assets | — | — | — | 1,104 | — | 1,104 |
| Impairment of goodwill | — | — | — | 1,019 | — | 1,019 |
| Total operating expenses | 239 | 14 | 54 | 41,333 | (78) | 41,562 |
| Operating income/(loss) | (239) | (14) | (54) | 5,045 | 78 | 4,816 |
| Income from equity investments | 302 | 142 | — | 1,360 | (295) | 1,509 |
| Equity earnings/(loss) from consolidated subsidiaries | 3,119 | (1,634) | 921 | (1,581) | (825) | — |
| Other | | | | | | |
| Net foreign currency gain/(loss) | (829) | 8 | — | 80 | 219 | (522) |
| Gain/(loss) on dispositions | 360 | — | — | (406) | — | (46) |
| Other, including other income/ (expense) from affiliates | 945 | 72 | 153 | 254 | (908) | 516 |
| Interest expense | (1,080) | (302) | (557) | (1,689) | 925 | (2,703) |
| Earnings/(loss) before income taxes | 2,578 | (1,728) | 463 | 3,063 | (806) | 3,570 |
| Income tax recovery/(expense) | 304 | (319) | 3 | (4,373) | 4,148 | (237) |
| Earnings/(loss) | 2,882 | (2,047) | 466 | (1,310) | 3,342 | 3,333 |
| Earnings attributable to noncontrolling interests and redeemable noncontrolling interests | — | — | — | — | (451) | (451) |
| Earnings/(loss) attributable to controlling interests | 2,882 | (2,047) | 466 | (1,310) | 2,891 | 2,882 |
| Preference share dividends | (367) | — | — | — | — | (367) |
| Earnings/(loss) attributable to common shareholders | 2,515 | (2,047) | 466 | (1,310) | 2,891 | 2,515 |
| Earnings/(loss) | 2,882 | (2,047) | 466 | (1,310) | 3,342 | 3,333 |
| Total other comprehensive income/ (loss) | 3,788 | (9) | 28 | 556 | (225) | 4,138 |
| Comprehensive income/(loss) | 6,670 | (2,056) | 494 | (754) | 3,117 | 7,471 |
| Comprehensive income attributable to noncontrolling interests | — | — | — | — | (801) | (801) |
| Comprehensive income/(loss) attributable to controlling interests | 6,670 | (2,056) | 494 | (754) | 2,316 | 6,670 |

**Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2017**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Operating revenues | | | | | | |
| Commodity sales | — | — | — | 26,286 | — | 26,286 |
| Gas distribution sales | — | — | — | 4,215 | — | 4,215 |
| Transportation and other services | — | — | — | 13,877 | — | 13,877 |
| Total operating revenues | — | — | — | 44,378 | — | 44,378 |
| Operating expenses | | | | | | |
| Commodity costs | — | — | — | 26,065 | — | 26,065 |
| Gas distribution costs | — | — | — | 2,572 | — | 2,572 |
| Operating and administrative | 169 | 146 | 16 | 6,111 | — | 6,442 |
| Depreciation and amortization | 56 | — | — | 3,107 | — | 3,163 |
| Impairment of long lived assets | — | — | — | 4,463 | — | 4,463 |
| Impairment of goodwill | — | — | — | 102 | — | 102 |
| Total operating expenses | 225 | 146 | 16 | 42,420 | — | 42,807 |
| Operating income/(loss) | (225) | (146) | (16) | 1,958 | — | 1,571 |
| Income from equity investments | 471 | 118 | — | 981 | (468) | 1,102 |
| Equity earnings from consolidated subsidiaries | 2,130 | 752 | 926 | 881 | (4,689) | — |
| Other | | | | | | |
| Net foreign currency gain/(loss) | 500 | — | — | (22) | (241) | 237 |
| Gain/(loss) on dispositions | (11) | — | — | 27 | — | 16 |
| Other, including other income/ (expense) from affiliates | 871 | 11 | 139 | 74 | (896) | 199 |
| Interest expense | (816) | (221) | (691) | (1,753) | 925 | (2,556) |
| Earnings before income taxes | 2,920 | 514 | 358 | 2,146 | (5,369) | 569 |
| Income tax (expense)/recovery | (61) | — | 9 | 2,706 | 43 | 2,697 |
| Earnings | 2,859 | 514 | 367 | 4,852 | (5,326) | 3,266 |
| Earnings attributable to noncontrolling interests and redeemable noncontrolling interests | — | — | — | — | (407) | (407) |
| Earnings attributable to controlling interests | 2,859 | 514 | 367 | 4,852 | (5,733) | 2,859 |
| Preference share dividends | (330) | — | — | — | — | (330) |
| Earnings attributable to common shareholders | 2,529 | 514 | 367 | 4,852 | (5,733) | 2,529 |
| Earnings | 2,859 | 514 | 367 | 4,852 | (5,326) | 3,266 |
| Total other comprehensive income/ (loss) | (2,031) | 12 | 204 | (412) | (51) | (2,278) |
| Comprehensive income | 828 | 526 | 571 | 4,440 | (5,377) | 988 |
| Comprehensive income attributable to noncontrolling interests | — | — | — | — | (160) | (160) |
| Comprehensive income attributable to controlling interests | 828 | 526 | 571 | 4,440 | (5,537) | 828 |

## Condensed Consolidating Statements of Financial Position as at December 31, 2019

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Assets** | | | | | | |
| Current assets | | | | | | |
| Cash and cash equivalents | — | 33 | 4 | 611 | — | **648** |
| Restricted cash | 9 | — | — | 19 | — | **28** |
| Accounts receivable and other | 429 | 8 | 4 | 6,340 | — | **6,781** |
| Accounts receivable from affiliates | 746 | — | 12 | (164) | (525) | **69** |
| Short-term loans receivable from affiliates | 1,691 | — | 3,961 | 4,417 | (10,069) | **—** |
| Inventory | — | — | — | 1,299 | — | **1,299** |
| | 2,875 | 41 | 3,981 | 12,522 | (10,594) | **8,825** |
| Property, plant and equipment, net | 248 | — | — | 93,475 | — | **93,723** |
| Long-term loans receivable from affiliates | 47,285 | 73 | 2,387 | 35,672 | (85,417) | **—** |
| Investments in subsidiaries | 80,456 | 18,956 | 5,180 | 14,782 | (119,374) | **—** |
| Long-term investments | 1,701 | 932 | — | 14,467 | (572) | **16,528** |
| Restricted long-term investments | — | — | — | 434 | — | **434** |
| Deferred amounts and other assets | 998 | 1 | 1 | 7,282 | (849) | **7,433** |
| Intangible assets, net | 247 | — | — | 1,926 | — | **2,173** |
| Goodwill | — | — | — | 33,153 | — | **33,153** |
| Deferred income taxes | 486 | — | — | 514 | — | **1,000** |
| Total assets | 134,296 | 20,003 | 11,549 | 214,227 | (216,806) | **163,269** |
| | | | | | | |
| **Liabilities and equity** | | | | | | |
| Current liabilities | | | | | | |
| Short-term borrowings | — | — | — | 898 | — | **898** |
| Accounts payable and other | 2,765 | 28 | 1 | 7,745 | (476) | **10,063** |
| Accounts payable to affiliates | 736 | 367 | 83 | (640) | (525) | **21** |
| Interest payable | 279 | 52 | 51 | 242 | — | **624** |
| Short-term loans payable to affiliates | 367 | 2,058 | 1,991 | 5,653 | (10,069) | **—** |
| Current portion of long-term debt | 2,160 | 518 | — | 1,726 | — | **4,404** |
| | 6,307 | 3,023 | 2,126 | 15,624 | (11,070) | **16,010** |
| Long-term debt | 27,290 | 4,435 | 3,789 | 24,147 | — | **59,661** |
| Other long-term liabilities | 1,295 | 2 | 12 | 7,864 | (849) | **8,324** |
| Long-term loans payable to affiliates | 33,686 | — | 3,112 | 48,619 | (85,417) | **—** |
| Deferred income taxes | — | 271 | — | 13,887 | (4,291) | **9,867** |
| | 68,578 | 7,731 | 9,039 | 110,141 | (101,627) | **93,862** |
| Equity | | | | | | |
| Controlling interests[1] | 65,718 | 12,272 | 2,510 | 104,086 | (118,543) | **66,043** |
| Noncontrolling interests | — | — | — | — | 3,364 | **3,364** |
| | 65,718 | 12,272 | 2,510 | 104,086 | (115,179) | **69,407** |
| Total liabilities and equity | 134,296 | 20,003 | 11,549 | 214,227 | (216,806) | **163,269** |

*1 Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.*

## Condensed Consolidating Statements of Financial Position as at December 31, 2018

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Assets** | | | | | | |
| Current assets | | | | | | |
| Cash and cash equivalents | — | 16 | — | 502 | — | 518 |
| Restricted cash | 9 | — | — | 110 | — | 119 |
| Accounts receivable and other | 283 | 15 | 8 | 6,211 | — | 6,517 |
| Accounts receivable from affiliates | 726 | — | 13 | (142) | (518) | 79 |
| Short-term loans receivable from affiliates | 3,943 | — | 3,689 | 653 | (8,285) | — |
| Inventory | — | — | — | 1,339 | — | 1,339 |
| | 4,961 | 31 | 3,710 | 8,673 | (8,803) | 8,572 |
| Property, plant and equipment, net | 140 | — | — | 94,400 | — | 94,540 |
| Long-term loans receivable from affiliates | 10,318 | 73 | 2,539 | 1,344 | (14,274) | — |
| Investments in subsidiaries | 78,474 | 19,777 | 6,363 | 15,567 | (120,181) | — |
| Long-term investments | 4,561 | 987 | — | 14,841 | (3,682) | 16,707 |
| Restricted long-term investments | — | — | — | 323 | — | 323 |
| Deferred amounts and other assets | 1,700 | 9 | 17 | 8,558 | (1,726) | 8,558 |
| Intangible assets, net | 234 | — | — | 2,138 | — | 2,372 |
| Goodwill | — | — | — | 34,459 | — | 34,459 |
| Deferred income taxes | 817 | — | — | 229 | 328 | 1,374 |
| Total assets | 101,205 | 20,877 | 12,629 | 180,532 | (148,338) | 166,905 |
| **Liabilities and equity** | | | | | | |
| Current liabilities | | | | | | |
| Short-term borrowings | — | — | — | 1,024 | — | 1,024 |
| Accounts payable and other | 2,742 | 7 | 34 | 7,059 | (6) | 9,836 |
| Accounts payable to affiliates | 946 | 233 | 56 | (677) | (518) | 40 |
| Interest payable | 283 | 56 | 105 | 225 | — | 669 |
| Short-term loans payable to affiliates | 426 | 682 | — | 7,177 | (8,285) | — |
| Environmental liabilities, current | — | — | — | 27 | — | 27 |
| Current portion of long-term debt | 1,853 | — | 683 | 723 | — | 3,259 |
| | 6,250 | 978 | 878 | 15,558 | (8,809) | 14,855 |
| Long-term debt | 22,893 | 7,276 | 6,943 | 23,215 | — | 60,327 |
| Other long-term liabilities | 2,428 | 2 | 30 | 8,100 | (1,726) | 8,834 |
| Long-term loans payable to affiliates | 76 | — | 1,502 | 12,696 | (14,274) | — |
| Deferred income taxes | — | 331 | — | 13,523 | (4,400) | 9,454 |
| | 31,647 | 8,587 | 9,353 | 73,092 | (29,209) | 93,470 |
| Equity | | | | | | |
| Controlling interests[1] | 69,558 | 12,290 | 3,276 | 107,440 | (123,094) | 69,470 |
| Noncontrolling interests | — | — | — | — | 3,965 | 3,965 |
| | 69,558 | 12,290 | 3,276 | 107,440 | (119,129) | 73,435 |
| Total liabilities and equity | 101,205 | 20,877 | 12,629 | 180,532 | (148,338) | 166,905 |

*1 Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.*

**Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2019**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Net cash provided by operating activities** | 2,246 | 1,676 | (365) | 9,675 | (3,834) | **9,398** |
| **Investing activities** | | | | | | |
| Capital expenditures | (75) | — | — | (5,417) | — | **(5,492)** |
| Long-term investments and restricted long-term investments | (26) | (11) | — | (1,122) | — | **(1,159)** |
| Distributions from equity investments in excess of cumulative earnings | — | 24 | 1,196 | 393 | (1,196) | **417** |
| Additions to intangible assets | (68) | — | — | (132) | — | **(200)** |
| Affiliate loans, net | — | — | — | (314) | — | **(314)** |
| Proceeds from disposition | — | — | — | 2,110 | — | **2,110** |
| Contributions to subsidiaries | (4,759) | — | (12) | — | 4,771 | **—** |
| Return of share capital from subsidiary companies | 5,281 | — | — | — | (5,281) | **—** |
| Advances to affiliates | (50,897) | — | (2,778) | (60,787) | 114,462 | **—** |
| Repayment of advances to affiliates | 15,808 | — | 2,357 | 22,136 | (40,301) | **—** |
| Other | — | — | — | (20) | — | **(20)** |
| **Net cash (used in)/provided by investing activities** | (34,736) | 13 | 763 | (43,153) | 72,455 | **(4,658)** |
| **Financing activities** | | | | | | |
| Net change in short-term borrowings | — | — | — | (127) | — | **(127)** |
| Net change in commercial paper and credit facility draws | 3,158 | (2,011) | (1,017) | 695 | — | **825** |
| Debenture and term note issues, net of issue costs | 3,621 | — | — | 2,555 | — | **6,176** |
| Debenture and term note repayments | (1,450) | — | (2,514) | (704) | — | **(4,668)** |
| Contributions from noncontrolling interests | — | — | — | — | 12 | **12** |
| Distributions to noncontrolling interests | — | — | — | — | (254) | **(254)** |
| Contributions from redeemable noncontrolling interests | — | — | — | — | — | **—** |
| Distributions to redeemable noncontrolling interests | — | — | — | — | — | **—** |
| Contributions from parents | — | — | — | 4,771 | (4,771) | **—** |
| Distributions to parents | — | (1,014) | (651) | (8,888) | 10,553 | **—** |
| Redemption of preferred shares | — | — | — | (300) | — | **(300)** |
| Common shares issued | 18 | — | — | — | — | **18** |
| Preference share dividends | (383) | — | — | — | — | **(383)** |
| Common share dividends | (5,973) | — | — | — | — | **(5,973)** |
| Advances from affiliates | 46,860 | 5,678 | 8,249 | 53,675 | (114,462) | **—** |
| Repayment of advances from affiliates | (13,361) | (4,321) | (4,454) | (18,165) | 40,301 | **—** |
| Other | — | (4) | (7) | (60) | — | **(71)** |
| **Net cash provided by/(used in) financing activities** | 32,490 | (1,672) | (394) | 33,452 | (68,621) | **(4,745)** |
| Effect of translation of foreign denominated cash and cash equivalents and restricted cash | — | — | — | 44 | — | **44** |
| Net increase/(decrease) in cash and cash equivalents and restricted cash | — | 17 | 4 | 18 | — | **39** |
| Cash and cash equivalents and restricted cash at beginning of year | 9 | 16 | — | 612 | — | **637** |
| Cash and cash equivalents and restricted cash at end of year | 9 | 33 | 4 | 630 | — | **676** |

**Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2018**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Net cash provided by/(used in) operating activities** | 1,696 | 1,751 | (239) | 11,683 | (4,389) | 10,502 |
| **Investing activities** | | | | | | |
| Capital expenditures | (28) | — | — | (6,778) | — | (6,806) |
| Long-term investments and restricted long-term investments | (81) | (12) | — | (1,297) | 78 | (1,312) |
| Distributions from equity investments in excess of cumulative earnings | 287 | 45 | 982 | 1,232 | (1,269) | 1,277 |
| Additions to intangible assets | (43) | — | — | (497) | — | (540) |
| Proceeds from dispositions | 1,790 | — | — | 2,662 | — | 4,452 |
| Contributions to subsidiaries | (8,131) | (79) | (13) | (1,655) | 9,878 | — |
| Return of share capital from subsidiaries | 3,753 | — | — | — | (3,753) | — |
| Advances to affiliates | (6,863) | — | (1,703) | (5,685) | 14,251 | — |
| Repayment of advances to affiliates | 9,427 | 518 | 1,504 | 4,124 | (15,573) | — |
| Affiliate loans, net | | | | (76) | | (76) |
| Other | — | — | — | (12) | — | (12) |
| **Net cash provided by/(used in) investing activities** | 111 | 472 | 770 | (7,982) | 3,612 | (3,017) |
| **Financing activities** | | | | | | |
| Net change in short-term borrowings | — | — | — | (420) | — | (420) |
| Net change in commercial paper and credit facility draws | (734) | (962) | (1,009) | 449 | — | (2,256) |
| Debenture and term note issues, net of issue costs | 2,554 | — | — | 983 | — | 3,537 |
| Debenture and term note repayments | — | (648) | (509) | (3,288) | — | (4,445) |
| Sale of noncontrolling interests in subsidiaries | — | — | — | — | 1,289 | 1,289 |
| Contributions from noncontrolling interests | — | — | — | — | 24 | 24 |
| Distributions to noncontrolling interests | — | — | — | — | (857) | (857) |
| Contributions from redeemable noncontrolling interests | — | — | — | — | 70 | 70 |
| Distributions to redeemable noncontrolling interests | — | — | — | — | (325) | (325) |
| Contributions from parents | — | — | 1,007 | 8,223 | (9,230) | — |
| Distributions to parents | — | (1,902) | (666) | (6,564) | 9,132 | — |
| Sponsored Vehicle buy-in cash payment | (64) | — | — | — | — | (64) |
| Redemption of preferred shares | — | — | — | (210) | — | (210) |
| Common shares issued | 21 | 648 | — | — | (648) | 21 |
| Preference share dividends | (364) | — | — | — | — | (364) |
| Common share dividends | (3,480) | — | — | — | — | (3,480) |
| Advances from affiliates | 710 | 1,474 | 3,501 | 8,566 | (14,251) | — |
| Repayment of advances from affiliates | (443) | (826) | (2,855) | (11,449) | 15,573 | — |
| Other | — | (5) | — | (18) | — | (23) |
| **Net cash (used in)/provided by financing activities** | (1,800) | (2,221) | (531) | (3,728) | 777 | (7,503) |
| Effect of translation of foreign denominated cash and cash equivalents and restricted cash | — | — | — | 68 | — | 68 |
| Net increase in cash and cash equivalents and restricted cash | 7 | 2 | — | 41 | — | 50 |
| Cash and cash equivalents and restricted cash at beginning of year | 2 | 14 | — | 571 | — | 587 |
| Cash and cash equivalents and restricted cash at end of year | 9 | 16 | — | 612 | — | 637 |

**Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2017**

| | Parent Issuer and Guarantor | Subsidiary Issuer and Guarantor - SEP | Subsidiary Issuer and Guarantor - EEP | Subsidiary Non-Guarantors | Consolidating and elimination adjustments | Consolidated - Enbridge |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Net cash (used in)/provided by operating activities** | 620 | 355 | (695) | 9,654 | (3,276) | 6,658 |
| **Investing activities** | | | | | | |
| Capital expenditures | (21) | — | — | (8,266) | — | (8,287) |
| Long-term investments and restricted long-term investments | (202) | (51) | — | (3,535) | 202 | (3,586) |
| Distributions from equity investments in excess of cumulative earnings | 36 | 22 | 921 | 103 | (957) | 125 |
| Additions to intangible assets | (47) | — | — | (742) | — | (789) |
| Cash acquired in Merger Transaction | — | — | — | 682 | — | 682 |
| Proceeds from dispositions | — | — | 1,742 | 1,103 | (2,217) | 628 |
| Contributions to subsidiaries | (4,866) | — | (2,056) | — | 6,922 | — |
| Return of share capital from subsidiaries | 2,192 | — | 1,532 | — | (3,724) | — |
| Advances to affiliates | (7,145) | (519) | (1,410) | (3,020) | 12,094 | — |
| Repayment of advances to affiliates | 4,506 | — | 2,129 | 2,887 | (9,522) | — |
| Affiliate loans, net | — | — | — | (22) | — | (22) |
| Other | — | — | — | 212 | — | 212 |
| **Net cash (used in)/provided by investing activities** | (5,547) | (548) | 2,858 | (10,598) | 2,798 | (11,037) |
| **Financing activities** | | | | | | |
| Net change in short-term borrowings | — | — | — | 721 | — | 721 |
| Net change in commercial paper and credit facility draws | (1,845) | 1,965 | (316) | (1,053) | — | (1,249) |
| Debenture and term note issues, net of issue costs | 8,177 | 519 | — | 787 | — | 9,483 |
| Debenture and term note repayments | (1,711) | (533) | — | (2,810) | — | (5,054) |
| Purchase of interest in consolidated subsidiary | — | — | (475) | (1,969) | 2,217 | (227) |
| Contributions from noncontrolling interests | — | — | — | — | 832 | 832 |
| Distributions to noncontrolling interests | — | — | — | — | (919) | (919) |
| Contributions from redeemable noncontrolling interests | 563 | — | — | — | 615 | 1,178 |
| Distributions to redeemable noncontrolling interests | — | — | — | — | (247) | (247) |
| Contributions from parents | — | — | — | 6,922 | (6,922) | — |
| Distributions to parents | — | (1,987) | (789) | (6,093) | 8,869 | — |
| Preference shares issued | 489 | — | — | — | — | 489 |
| Redemption of preferred shares | — | — | (1,613) | 1,613 | — | — |
| Common shares issued | 1,549 | 227 | 1,646 | — | (1,873) | 1,549 |
| Preference share dividends | (330) | — | (478) | — | 478 | (330) |
| Common share dividends[1] | (2,336) | — | — | (414) | — | (2,750) |
| Advances from affiliates | 407 | — | 2,613 | 9,074 | (12,094) | — |
| Repayment of advances from affiliates | (40) | — | (2,847) | (6,635) | 9,522 | — |
| **Net cash provided by/(used in) financing activities** | 4,923 | 191 | (2,259) | 143 | 478 | 3,476 |
| Effect of translation of foreign denominated cash and cash equivalents and restricted cash | — | — | (2) | (70) | — | (72) |
| Net decrease in cash and cash equivalents and restricted cash | (4) | (2) | (98) | (871) | — | (975) |
| Cash and cash equivalents and restricted cash at beginning of year | 6 | 16 | 98 | 1,442 | — | 1,562 |
| Cash and cash equivalents and restricted cash at end of year | 2 | 14 | — | 571 | — | 587 |

*1 Common share dividends for the year ended December 31, 2017 includes amounts distributed by Spectra Energy Corp. related to dividends accrued prior to the Merger Transaction.*

## 33. QUARTERLY FINANCIAL DATA (UNAUDITED)

| *(unaudited; millions of Canadian dollars, except per share amounts)* | **Q1** | **Q2** | **Q3** | **Q4** | **Total** |
|---|---|---|---|---|---|
| 2019 | | | | | |
| Operating revenues | **12,856** | **13,263** | **11,598** | **12,352** | **50,069** |
| Operating income | **2,619** | **2,285** | **1,588** | **1,768** | **8,260** |
| Earnings | **2,023** | **1,830** | **1,060** | **914** | **5,827** |
| Earnings attributable to controlling interests | **1,986** | **1,832** | **1,045** | **842** | **5,705** |
| Earnings attributable to common shareholders | **1,891** | **1,736** | **949** | **746** | **5,322** |
| Earnings per common share | | | | | |
| Basic | **0.94** | **0.86** | **0.47** | **0.37** | **2.64** |
| Diluted | **0.94** | **0.86** | **0.47** | **0.36** | **2.63** |
| 2018 | | | | | |
| Operating revenues | 12,726 | 10,745 | 11,345 | 11,562 | 46,378 |
| Operating income | 878 | 1,571 | 854 | 1,513 | 4,816 |
| Earnings | 510 | 1,327 | 213 | 1,283 | 3,333 |
| Earnings attributable to controlling interests | 534 | 1,160 | 4 | 1,184 | 2,882 |
| Earnings/(loss) attributable to common shareholders | 445 | 1,071 | (90) | 1,089 | 2,515 |
| Earnings/(loss) per common share | | | | | |
| Basic | 0.26 | 0.63 | (0.05) | 0.60 | 1.46 |
| Diluted | 0.26 | 0.63 | (0.05) | 0.60 | 1.46 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

**DISCLOSURE CONTROLS AND PROCEDURES**

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As at December 31, 2019, an evaluation was carried out under the supervision of and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

**INTERNAL CONTROL OVER FINANCIAL REPORTING**

**Management's Annual Report on Internal Control over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. Our internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with U.S. GAAP.

Our internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Our internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with our policies and procedures.

Our management assessed the effectiveness of our internal control over financial reporting as at December 31, 2019, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as at December 31, 2019.

The effectiveness of our internal control over financial reporting as at December 31, 2019 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by our shareholders. As stated in their *Report of Independent Registered Public Accounting Firm* which appears in *Item 8. Financial Statements and Supplementary Data*, they expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2019.

**Changes in Internal Control Over Financial Reporting**
During the three months ended December 31, 2019, there has been no material change in our internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

**Directors of Registrant**
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

**Executive Officers of Registrant**
The information regarding executive officers is included in Part I. *Item 1. Business - Executive Officers.*

**Code of Ethics for Chief Executive Officer and Senior Financial Officers**
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

## ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

# PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Enbridge Inc.:

Report of Independent Registered Public Accounting Firm
Consolidated Statements of Earnings
Consolidated Statements of Comprehensive Income
Consolidated Statements of Changes in Equity
Consolidated Statements of Cash Flows
Consolidated Statements of Financial Position
Notes to the Consolidated Financial Statements

All schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits:

Reference is made to the “Index of Exhibits” following Item 16. *Form 10-K Summary*, which is hereby incorporated into this Item.

## ITEM 16. FORM 10-K SUMMARY

None.

## INDEX OF EXHIBITS

Each exhibit identified below is included as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement.

| Exhibit No. | | Name of Exhibit |
|---|---|---|
| | | |
| 2.1 | | Agreement and Plan of Merger, dated as of September 5, 2016, by and among Spectra Energy Corp, Enbridge Inc. and Sand Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 2.2 | | Contribution Agreement dated as of June 18, 2015 among Enbridge Inc., IPL System Inc., Enbridge Income Fund Holdings Inc., Enbridge Income Fund, Enbridge Commercial Trust and Enbridge Income Partners LP (incorporated by reference to Exhibit 2.2 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 2.3 | | Agreement and Plan of Merger, dated as of August 24, 2018, by and among Spectra Energy Partners, LP, Spectra Energy Partners (DE) GP, LP, Enbridge Inc., Enbridge (U.S.) Inc., Autumn Acquisition Sub, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc., Spectra Energy Corp, Spectra Energy Capital, LLC and Spectra Energy Transmission, LLC. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed August 24, 2018) |
| 2.4 | | Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Partners, L.P., Enbridge Energy Company, Inc., Enbridge Energy Management, L.L.C., Enbridge Inc., Enbridge (U.S.) Inc., Winter Acquisition Sub II, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed September 18, 2018) |
| 2.5 | | Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Management, L.L.C., Enbridge Inc., Winter Acquisition Sub I, Inc., and solely for the purposes of Article I, Section 2.4 and Article X, Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 2.2 to Enbridge's Form 8-K filed September 18, 2018) |
| 2.6 | | Arrangement Agreement, dated as of September 17, 2018, by and between Enbridge Inc. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 2.3 to Enbridge's Form 8-K filed September 18, 2018) |
| 3.1 | | Articles of Continuance of the Corporation, dated December 15, 1987 (incorporated by reference to Exhibit 2.1(a) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.2 | | Certificate of Amendment, dated August 2, 1989, to the Articles of the Corporation (incorporated by reference to Exhibit 2.1(b) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.3 | | Articles of Amendment of the Corporation, dated April 30, 1992 (incorporated by reference to Exhibit 2.1(c) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.4 | | Articles of Amendment of the Corporation, dated July 2, 1992 (incorporated by reference to Exhibit 2.1(d) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.5 | | Articles of Amendment of the Corporation, dated August 6, 1992 (incorporated by reference to Exhibit 2.1(e) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.6 | | Articles of Arrangement of the Corporation dated December 18, 1992, attaching the Arrangement Agreement, dated December 15, 1992 (incorporated by reference to Exhibit 2.1(f) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |

| | | |
|---|---|---|
| 3.7 | | Certificate of Amendment of the Corporation (notarial certified copy), dated December 18, 1992 (incorporated by reference to Exhibit 2.1(g) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.8 | | Articles of Amendment of the Corporation, dated May 5, 1994 (incorporated by reference to Exhibit 2.1(h) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.9 | | Certificate of Amendment, dated October 7, 1998 (incorporated by reference to Exhibit 2.1(i) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.10 | | Certificate of Amendment, dated November 24, 1998 (incorporated by reference to Exhibit 2.1(j) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.11 | | Certificate of Amendment, dated April 29, 1999 (incorporated by reference to Exhibit 2.1(k) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001) |
| 3.12 | | Certificate of Amendment, dated May 5, 2005 (incorporated by reference to Exhibit 2.1(l) to Enbridge's Registration Statement on Form S-8 filed August 5, 2005) |
| 3.13 | | Certificate of Amendment, dated May 11, 2011 (incorporated by reference to Exhibit 3.13 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.14 | | Certificate of Amendment, dated September 28, 2011 (incorporated by reference to Exhibit 3.14 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.15 | | Certificate of Amendment, dated November 21, 2011 (incorporated by reference to Exhibit 3.15 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.16 | | Certificate of Amendment, dated January 16, 2012 (incorporated by reference to Exhibit 3.16 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.17 | | Certificate of Amendment, dated March 27, 2012 (incorporated by reference to Exhibit 3.17 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.18 | | Certificate of Amendment, dated April 16, 2012 (incorporated by reference to Exhibit 3.18 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.19 | | Certificate of Amendment, dated May 17, 2012 (incorporated by reference to Exhibit 3.19 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.20 | | Certificate of Amendment, dated July 12, 2012 (incorporated by reference to Exhibit 3.20 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.21 | | Certificate of Amendment, dated September 11, 2012 (incorporated by reference to Exhibit 3.21 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.22 | | Certificate of Amendment, dated December 3, 2012 (incorporated by reference to Exhibit 3.22 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.23 | | Certificate of Amendment, dated March 25, 2013 (incorporated by reference to Exhibit 3.23 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.24 | | Certificate of Amendment, dated June 4, 2013 (incorporated by reference to Exhibit 3.24 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.25 | | Certificate of Amendment, dated September 25, 2013 (incorporated by reference to Exhibit 3.25 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.26 | | Certificate of Amendment, dated December 10, 2013 (incorporated by reference to Exhibit 3.26 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.27 | | Certificate of Amendment, dated March 10, 2014 (incorporated by reference to Exhibit 3.27 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.28 | | Certificate of Amendment, dated May 20, 2014 (incorporated by reference to Exhibit 3.28 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |

| | | |
|---|---|---|
| 3.29 | | Certificate of Amendment, dated July 15, 2014 (incorporated by reference to Exhibit 3.29 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.30 | | Certificate of Amendment, dated September 19, 2014 (incorporated by reference to Exhibit 3.30 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017) |
| 3.31 | | Certificate of Amendment, dated November 22, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 1, 2016) |
| 3.32 | | Certificate of Amendment, dated December 15, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 16, 2016) |
| 3.33 | | Certificate of Amendment, dated July 13, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 13, 2017) |
| 3.34 | | Certificate of Amendment, dated September 25, 2017 (incorporated by reference to Exhibit 3.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 3.35 | | Certificate of Amendment, dated December 7, 2017 (incorporated by reference to Exhibit 3.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 3.36 | | Certificate of Amendment, dated February 27, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed March 1, 2018) |
| 3.37 | | Certificate of Amendment, dated April 9, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018) |
| 3.38 | | Certificate of Amendment, dated April 10, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018) |
| 3.39 | * | General By-Law No. 1 of Enbridge Inc. |
| 3.40 | | By-Law No. 2 of Enbridge Inc. (incorporated by reference to Enbridge's Current Report on Form 6-K filed December 5, 2014) |
| 4.1 | | Form of Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas to be dated February 25, 2005 (incorporated by reference to Exhibit 7.1 to Enbridge's Registration Statement on Form F-10 filed February 4, 2005) |
| 4.2 | | First Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2012 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed May 11, 2012) |
| 4.3 | | Second Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated December 19, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 20, 2016) |
| 4.4 | | Third Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 14, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 14, 2017) |
| 4.5 | | Fourth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed March 1, 2018) |
| 4.6 | | Fifth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated April 12, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed April 12, 2018) |
| 4.7 | | Sixth Supplemental Indenture between Enbridge Inc., Spectra Energy Partners, LP (as guarantor), Enbridge Energy Partners, L.P. (as guarantor) and Deutsche Bank Trust Company Americas, dated May 13, 2019 (incorporated by reference to Enbridge's Registration Statement on Form S-3 filed May 17, 2019) |
| 4.8 | | Shareholder Rights Plan Agreement dated as of November 9, 1995 and amended and restated as of May 1, 1996, February 24, 1999, May 3, 2002, May 5, 2005, May 7, 2008, May 11, 2011, May 7, 2014 and May 11, 2017 between Enbridge Inc. and CST Trust Company (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed May 12, 2017) |
| 4.9 | * | Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended |

| | | |
|---|---|---|
| | | Certain instruments defining the rights of holders of long-term debt securities of the Registrant and its subsidiaries are omitted pursuant to Item 601(b)(4)(iii) of Regulation S-K. The Registrant hereby undertakes to furnish to the SEC, upon request, copies of any such instruments. |
| 10.1 | | Enbridge Pipelines Inc. Competitive Toll Settlement dated July 1, 2011 (incorporated by reference to Exhibit 10.1 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.2 | | Sixteenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as trustee (incorporated by reference as Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed January 24, 2019) |
| 10.3 | | Seventeenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P., Enbridge Inc. and U.S. Bank National Association, as trustee (incorporated by reference as Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed January 24, 2019) |
| 10.4 | | Seventh Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.3 to Enbridge's Current Report on Form 8-K filed January 24, 2019) |
| 10.5 | | Eighth Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed January 24, 2019) |
| 10.6 | | Subsidiary Guarantee Agreement dated as of January 22, 2019 between Spectra Energy Partners, LP and Enbridge Energy Partners, L.P. (incorporated by reference as Exhibit 4.5 to Enbridge's Current Report on Form 8-K filed January 24, 2019) |
| 10.7 | + | Form of Executive Employment Agreement (pre-2014) (incorporated by reference to Exhibit 10.2 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.8 | + | Form of Executive Employment Agreement (2014-2016) (incorporated by reference to Exhibit 10.3 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.9 | + | Form of Executive Employment Agreement (2017) (incorporated by reference to Exhibit 10.4 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.10 | + | Executive Employment Agreement between Enbridge Employee Services, Inc. and William T. Yardley, dated July 25, 2018 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 8-K filed July 27, 2018) |
| 10.11 | + | Form of Director Indemnity Agreement (2015) (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 15, 2019) |
| 10.12 | + | Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge's Proxy Statement on Schedule 14A for Enbridge's Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019) |
| 10.13 | + | Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 10, 2019) |
| 10.14 | + | Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 10, 2019) |
| 10.15 | + | Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 10, 2019) |
| 10.16 | + | Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.7 to Enbridge's Form 10-Q filed May 10, 2019) |

| | | |
|---|---|---|
| 10.17 | + | Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version (incorporated by reference to Exhibit 10.8 to Enbridge's Form 10-Q filed August 2, 2019) |
| 10.18 | + | Enbridge Inc. Performance Stock Option Plan (2007) (Canadian) (incorporated by reference to Exhibit 10.5 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.19 | + | Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.6 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.20 | + | Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) and as further amended (2012) (incorporated by reference to Exhibit 10.7 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.21 | + | Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) and as further amended (2012 and 2014) (incorporated by reference to Exhibit 10.8 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.22 | + | Enbridge Inc. Performance Stock Unit Plan (2007), as revised (incorporated by reference to Exhibit 10.10 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.23 | + | Enbridge Inc. Restricted Stock Unit Plan (2006), as revised (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.24 | + | Enbridge Inc. Incentive Stock Option Plan (2007) (incorporated by reference to Exhibit 10.12 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.25 | + | Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.13 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.26 | + | Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011 and 2014) (incorporated by reference to Exhibit 10.14 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.27 | + | Enbridge Inc. Incentive Stock Option Plan (2007), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.28 | + | Enbridge Inc. Directors' Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019 (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 10, 2019) |
| 10.29 | + | Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Form 10-Q filed May 10, 2018) |
| 10.30 | + | Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 10, 2019) |
| 10.31 | + | Enbridge Inc. Short Term Incentive Plan (2007), as revised (incorporated by reference to Exhibit 10.17 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.32 | + | The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2018 (incorporated by reference as Exhibit 10.1 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018) |
| 10.33 | + | Amendment No. 1 and Amendment No. 2 to The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2005 (incorporated by reference to Exhibit 10.19 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.34 | + | Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.20 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |

| | | |
|---|---|---|
| 10.35 | + | Amendment 1 and Amendment 2 to the Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.21 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.36 | + | Third Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference as Exhibit 10.2 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018) |
| 10.37 | + | Spectra Energy Corp Directors' Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.22 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.38 | + | Spectra Energy Corp Executive Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.23 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.39 | + | Spectra Energy Executive Cash Balance Plan, as amended and restated (incorporated by reference to Exhibit 10.24 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.40 | + | Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.41 | + | Form of Spectra Energy Corp Change in Control Agreement (As Amended and Restated) (incorporated by reference to Exhibit 10.26 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.42 | + | Form of Spectra Energy Corp Stock Option Agreement (Nonqualified Stock Options) (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.43 | + | Spectra Energy Corp 2007 Long-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.32 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.44 | + | Form of Spectra Energy Corp Phantom Stock Award Agreement (2017) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Cash-settled) (incorporated by reference to Exhibit 10.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.45 | + | Form of Spectra Energy Corp Phantom Stock Award Agreement (2017) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Stock-settled) (incorporated by reference to Exhibit 10.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.46 | + | Second Amendment to the Spectra Energy Corp Executive Savings Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.36 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 10.47 | + | Second Amendment to the Spectra Energy Corp Executive Cash Balance Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.37 to Enbridge's Annual Report on Form 10-K filed February 16, 2018) |
| 21.1 | * | Subsidiaries of the Registrant |
| 23.1 | * | Consent of PricewaterhouseCoopers LLP |
| 24.1 | | Powers of Attorney (included on the signature page of the Annual Report) |
| 31.1 | * | Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | * | Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | * | Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | * | Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

| | | |
|---|---|---|
| 101.INS | * | XBRL Instance Document. |
| 101.SCH | * | XBRL Taxonomy Extension Schema. |
| 101.CAL | * | XBRL Taxonomy Extension Calculation Linkbase. |
| 101.DEF | * | XBRL Taxonomy Extension Definition Linkbase. |
| 101.LAB | * | XBRL Taxonomy Extension Label Linkbase. |
| 101.PRE | * | XBRL Taxonomy Extension Presentation Linkbase. |

## SIGNATURES

**POWER OF ATTORNEY**

Each person whose signature appears below appoints Robert R. Rooney, Colin K. Gruending and Karen K. L. Uehara, and each of them, any of whom may act without the joinder of the other, as their true and lawful attorneys-in-fact and agents, with full power of substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Enbridge on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**ENBRIDGE INC.**
(Registrant)

Date: February 14, 2020

By: /s/ Al Monaco
Al Monaco
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 14, 2020 by the following persons on behalf of the registrant and in the capacities indicated.

| | |
|---|---|
| /s/ Al Monaco | /s/ Colin K. Gruending |
| Al Monaco<br>*President, Chief Executive Officer and Director (Principal Executive Officer)* | Colin K. Gruending<br>*Executive Vice President and Chief Financial Officer (Principal Financial Officer)* |
| /s/ Mark A. Maki | /s/ Gregory L. Ebel |
| Mark A. Maki<br>*Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)* | Gregory L. Ebel<br>*Chairman of the Board of Directors* |
| /s/ Pamela L. Carter | /s/ Marcel R. Coutu |
| Pamela L. Carter<br>*Director* | Marcel R. Coutu<br>*Director* |
| /s/ Susan M. Cunningham | /s/ J. Herb England |
| Susan M. Cunningham<br>*Director* | J. Herb England<br>Director |
| /s/ Charles W. Fischer | /s/ Gregory J. Goff |
| Charles W. Fischer<br>Director | Gregory J. Goff<br>Director |
| /s/ V. Maureen Kempston Darkes | /s/ Teresa S. Madden |
| V. Maureen Kempston Darkes<br>Director | Teresa S. Madden<br>Director |
| /s/ Dan C. Tutcher | /s/ Cathy L. Williams |
| Dan C. Tutcher<br>Director | Cathy L. Williams<br>Director |

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# Investor Information

## Investor Inquiries

If you have inquiries regarding the following:

- The latest news releases or investor presentations
- Any investment-related inquiries

Please contact Enbridge Investor Relations
Toll-free: 1-800-481-2804
investor.relations@enbridge.com

Enbridge Inc.
200, 425 – 1 Street S.W.
Calgary, Alberta, Canada T2P 3L8

Telephone: 1-403-231-3900
Facsimile: 1-403-231-3920
enbridge.com

## Registrar and Transfer Agent

For information relating to shareholdings, shareholder investment plan, dividends, direct dividend deposit and lost certificates, please contact:

**Computershare Trust Company of Canada**
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1

Toll-free North America: 1-866-276-9479
Outside North America: 1-514-982-8696
computershare.com/enbridge

## Auditors

PricewaterhouseCoopers LLP

## 2020 Enbridge Inc. Common Share Dividends

| | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| Dividend | $0.81 | $ – [2] | $ – [2] | $ – [2] |
| Payment date | Mar 01 | Jun 01 | Sep 01 | Dec 01 |
| Record date[1] | Feb 14 | May 15 | Aug 14 | Nov 13 |

[1] Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.

[2] Amount will be announced as declared by the Board of Directors.

*On November 2, 2018, Enbridge Inc. announced that it has suspended its dividend reinvestment and share purchase plan (DRIP) until further notice.*

## Common and Preference Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB." The Preference Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series C – ENB.PR.C
Series D – ENB.PR.D
Series F – ENB.PR.F
Series H – ENB.PR.H
Series J – ENB.PR.U
Series L – ENB.PF.U
Series N – ENB.PR.N
Series P – ENB.PR.P
Series R – ENB.PR.T

Series 1 – ENB.PR.V
Series 3 – ENB.PR.Y
Series 5 – ENB.PF.V
Series 7 – ENB.PR.J
Series 9 – ENB.PF.A
Series 11 – ENB.PF.C
Series 13 – ENB.PF.E
Series 15 – ENB.PF.G
Series 17 – ENB.PF.I
Series 19 – ENB.PF.K

**Forward-Looking Information**

This Annual Report includes references to forward-looking information. By its nature this information involves certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect our business. The more significant factors and risks that might affect our future outcomes are listed and discussed in the "Forward-Looking Information" and Risk Factors sections of our Form 10-K and Management's Discussion & Analysis, included in this Annual Report and available on both sedar.com and sec.gov.

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper containing post-consumer waste fiber.

FSC www.fsc.org MIX Paper from responsible sources FSC® C015495

# OMERS 2019 ANNUAL REPORT

OMERS

# 2019 ANNUAL REPORT

TAKING STOCK | MOVING FORWARD | CREATING VALUE

# WE ARE OMERS

## A jointly sponsored, defined benefit pension plan, with 1,000 participating employers ranging from large cities to local agencies, and over half a million active, deferred and retired members.

Our members include union and non-union employees of municipalities, school boards, local boards, transit systems, electrical utilities, emergency services and children's aid societies across Ontario. Contributions to the Plan are funded equally by members and employers.

OMERS teams work in Toronto, London, New York, Amsterdam, Luxembourg, Singapore, Sydney and other major cities across North America and Europe – serving members and employers and originating and managing a diversified portfolio of high-quality investments in public markets, private equity, infrastructure and real estate.

The benefits OMERS provides are funded equally from active members' and their employers' contributions, combined with investment income. We estimate that, on average, active members today will have approximately 70% of their lifetime benefits funded by investment returns.

OMERS actively seeks out opportunities to engage with decision-makers to advocate the advantages of the jointly sponsored defined benefit pension model.

The OMERS Pension Plans comprise the OMERS Primary Pension Plan, the Retirement Compensation Arrangement (RCA) for the OMERS Primary Pension Plan, and the Supplemental Pension Plan for Police, Firefighters and Paramedics, which has no assets, liabilities or members. When we refer to the "OMERS Plan" or the "Plan" in our communications, it is the OMERS Primary Pension Plan that we are typically referring to, unless otherwise specified. When we refer to the "OMERS Act", it is to the OMERS Act, 2006, as amended.

**500,000+** Members

**97%**
Funded Ratio

**11.9%**
Net Rate of Return

**5.90%**
Discount Rate

**8.5%**
5-Year Average
Net Rate of Return

**$109**
Billion In Net Assets

**$32,491**
Average annual pension for members retiring in 2019

The current average contribution rate paid by members is 10.6% which is matched equally by employers.

Contribution rates and benefit accruals remain unchanged for 2020. Pension payments to retired members increased by a cost of living adjustment of 2.29% in 2019 and of 1.89% in 2020.

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This Annual Report is addressed to our members, employers, sponsors, unions, associations, and the many others who are interested in OMERS 2019 performance, and in our progress in making OMERS a sustainable, affordable and meaningful defined benefit Plan.


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# HIGHLIGHTS FOR OUR MEMBERS

**These first few pages provide highlights from the past year, address the questions we receive most often, and look ahead as we continue with our refreshed strategy. We end with a discussion about OMERS broader impact and responsibilities.**

**94%**
Member Satisfaction

**$32,491**
Average annual pension for members retiring in 2019

**92%**
Employer Satisfaction

# TAKING STOCK

**In 2019, we achieved an 11.9% net investment return, with positive performance across all asset classes. Public equity returns were particularly strong this year. Our 2019 performance exceeds last year's net return of 2.3%, which was impacted by challenging stock market conditions, and also exceeds our benchmark of 7.5%. Over the past five years, our average net rate of return has been 8.5%.**

This strong long-term investment performance, combined with contributions from our members and employers, improved our smoothed funded ratio to 97% – an increase of 1% from last year and the seventh consecutive year of improvement. On a fair value basis (i.e., without smoothing), our funded status is 101%.

| NET RETURN HISTORY | | | | |
|---|---|---|---|---|
| 1-Year | 3-Year | 5-Year | 10-Year | 20-Year |
| 11.9% | 8.5% | 8.5% | 8.2% | 6.5% |

We use a discount rate to calculate the value of our pension obligations. In 2019, we reduced our real discount rate by 10 basis points, from 4.00% to 3.90%, reflecting the increasing risks the Plan is facing. We assume annual inflation of 2.00%, so our pension obligations are discounted at an all-in rate of 5.90% at December 31, 2019.

Since we began operating under our 2020 Strategy five years ago, our smoothed funded status has improved by 6%. Over the same period, we've reduced our discount rate by 35 basis points, exceeding the 25 basis points target we set in 2015. During that period, we have earned $9.8 billion of net investment income over the amount required to fund our liabilities.

Today, our long-term pension obligations are valued at $106 billion. These obligations are backed by our global portfolio of high-quality, well-diversified assets, with a fair value of $109 billion. As we invest and manage these assets, we apply our sustainable investing practices, which are described in later pages of our Annual Report.

For an overview of 2019 investment activity, visit www.omers.com/investing.

**PENSION TERMINOLOGY**

The **"funded ratio"** is the ratio of net investment assets to long-term pension obligations. It is an indicator of the long-term financial health of the Plan. It can be calculated on a "smoothed" or "fair value" basis:

"**Fair value**" uses year-end values of OMERS assets, without any adjustments. Because our investment returns vary each year, this calculation results in a funded ratio that may also vary year over year.

"**Smoothed**" evens out the variations in annual returns over a five-year period. In this way, contribution rates and benefits are set using a more stable, long-term view of investment performance.

The "**discount rate**" is the interest rate used to estimate the dollar value of OMERS long-term pension obligations. It includes two components: a "real" rate before inflation and net of a margin for risk, and an inflation estimate. Setting the discount rate is key to managing the Plan and addressing risk. Lowering it increases the dollar value of our pension obligations and therefore decreases our funded ratio but makes the Plan more resilient. Lowering the discount rate also ensures that contribution rates are set to properly fund liabilities.

"**Jointly sponsored pension plans**" are those in which decision-making and contributions are shared by both members and employers.

| | Contribution Rates | |
|---|---|---|
| | Normal Retirement (Age 60) | Normal Retirement (Age 65) |
| On earnings up to $57,400 | 9.20% | 9.00% |
| On earnings above $57,400 | 15.80% | 14.60% |

**One of our top priorities for 2019 was to find new ways to improve how we support and provide service to our members and employers. We have made good progress.**

We upgraded myOMERS, our online member portal. In addition to accessing your accrued benefit and pension information, new features enable you to update your beneficiary, address and banking information online, as well as connect with our Member Services representatives through secure online communications. Investing in a new member relationship management system is helping us work more efficiently and improves how we stay connected to you. This system's capabilities will continue to increase as we introduce more features and functionality.

**This past year we also made efforts to get to know you personally:**

- Our President, Blake Hutcheson, and our Chief Pension Officer, Annesley Wallace, visited five cities across Ontario, met with 700 members and retirees and answered over 100 questions. Plans are already underway for the 2020 President's Roadshow.
- 26,000 members participated in our Member Engagement Survey.
- We talked to recently retired, or about-to-retire members who volunteered to share their expectations, experience and myths about retirement. Their candid thoughts will help us improve the member experience in the years leading up to and following retirement.

**200,920**
Member phone calls handled by Member Services

For employers, we launched our Employer Monthly newsletter – a collection of timely, plan-related content. We provided personalized training, aimed at enhancing employers' understanding of Plan administration. We listened to feedback on how to improve our employer web portal, which will be a focus area in 2020.

And we implemented a new method for measuring employer satisfaction, providing us more meaningful information about the employer experience. We achieved 92% employer satisfaction in 2019.

## WE WANT TO CONTINUE THE CONVERSATION WITH YOU, OUR MEMBERS.

You are invited to attend

OMERS Annual Meeting:
April 8, 2020, 9:00 a.m.
Metro Toronto Convention Centre, South Building

# MOVING FORWARD

**In May 2019, we refreshed our 2020 Strategy, setting out our key areas of focus for the next five years. This 2025 Strategy keeps us on the path to making OMERS a sustainable, affordable and meaningful Plan, while managing challenges across the pension landscape.**

Similar to many pension plans across the globe, OMERS is experiencing demographic and social shifts that will make our future different from our past:

- Over time, there will be more members receiving retirement benefits from the OMERS Plan than there will be contributing to it. This "plan maturity" means that the Plan will have a reduced ability to recover from unanticipated events that could occur in the future – and the impact from those events could be more severe – especially for active members and employers.
- Members are living longer than they have in the past. This means that OMERS must be able to pay pensions for longer and we have to carefully consider how this impacts future investing, contributions and Plan design decisions.
- Work is changing. Automation is affecting many jobs and part-time employment is increasing. This means that the profile of our membership decades from now will likely be significantly different from our membership today. We need to plan today for a variety of outcomes.
- Investment markets are changing. Aging populations around the globe reduce our expectations for economic growth and point to a sustained period of low interest rates. The risks of geopolitical unrest have become high. OMERS needs to prepare for a more volatile and lower return environment.

The success of our strategy depends overwhelmingly on the strength of our people — who are strongest when they can bring their whole selves to work.

For us, inclusion means belonging. At OMERS, 92% of employees say they feel they belong, and 88% feel the OMERS environment enables them to be themselves at work. While we are encouraged by these metrics, we remain focused on fostering an environment of belonging.

We build inclusion from the ground up in several ways: we invest in programs and development opportunities to accelerate personal and professional growth. We support employees in establishing resource groups they feel are important. And we celebrate the diversity of cultures across the organization and around the world.

**Here's how our 2025 Strategy addresses these challenges:**

**EVOLVING** the OMERS Plan. We aim to ensure its continued sustainability, and to meet stakeholders' needs through exploring Plan design modernization, simplification and membership growth.

**ENSURING** the Plan's financial health. We will continue to manage its funded status and its discount rate, among other inputs. For example, we believe that contribution rates are unlikely to decrease in the foreseeable future, even after the Plan achieves full funding.

**MAINTAINING** a diverse investment portfolio. Our priorities include diversifying globally and continuing to incorporate Environmental, Social, and Governance factors into our investment decisions.

**IMPROVING** stakeholder trust and understanding. We are focused on enhancing stakeholder engagement, government relations and our service delivery to our members.

**ADVANCING** our operational capabilities. We know that talent depth, data and technology, and costs are important to executing our strategy.

In early 2020, the SC announced potential Plan design changes that it is considering; more information is available at www.omerssc.com. OMERS has scheduled Sponsor and Stakeholder Forums for April and May 2020 to discuss these potential changes, and we anticipate the SC will make and announce a final decision in June.

**We will continue to share with you our progress against this strategy, in the regular communications you receive from us, at our forums and meetings with Sponsors and Stakeholders and annually in this report to members.**

# CREATING VALUE FOR OUR COMMUNITIES

**While we focus on executing our strategy, we also know that our actions impact more than our immediate stakeholders.**

We know that our direct economic impact to the province of Ontario is meaningful. In 2019, OMERS paid $4.6 billion of pension benefits to more than 170,000 members, most of whom live in Ontario. These payments, combined with OMERS investments in the province, contributed over $10 billion† to the Ontario economy. Our retired members' spending also helps support some 63,000† jobs in communities across Ontario.

These economic benefits are just one reason that OMERS has become an increasingly vocal advocate for the defined benefit pension model. We know that:

- Defined benefit and particularly, jointly sponsored pension plans, provide financial benefits to communities. They compel members to save for retirement. They pool risks from multiple investments and from thousands of individuals – those entering the workforce and those enjoying retirement – into one diversified, lower-risk plan. They also provide professional investment management while lowering costs.
- Defined benefit pensions benefit society: our research shows that on average, our members are healthier, more financially secure, and more likely to volunteer in their communities, than those without a defined benefit pension. These qualities reduce the demand that would otherwise be met by government services.

**$4.6** Billion pension benefits paid

**$10** Billion contribution to Ontario's economy from OMERS activities†

**63,000** Jobs in Ontario communities are supported through OMERS pension payments†

**100,000+** Jobs in Ontario communities supported through OMERS activities†

For these reasons, we have made it a priority to promote our defined benefit pension model: our Senior Executive, government relations and communications teams actively seek out opportunities to engage with decision-makers to advocate the advantages of the jointly sponsored, defined benefit pension system.

† *OMERS and its Members: Ontario Economic Contribution.* Canadian Centre for Economic Analysis. February 2020.

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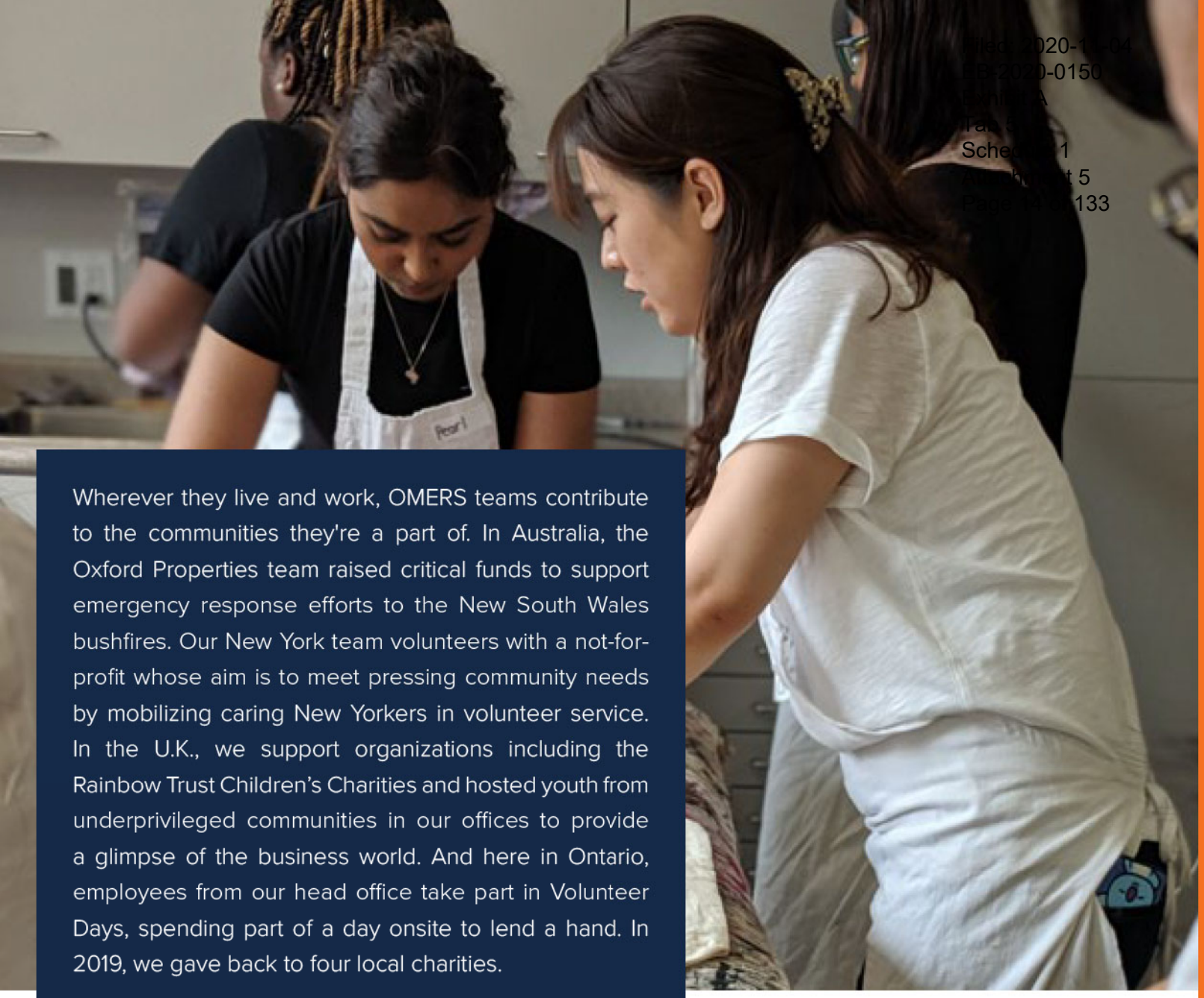
Exhibit A
Tab 5
Schedule 1
Attachment 5
Page [illegible] of 133



Wherever they live and work, OMERS teams contribute to the communities they're a part of. In Australia, the Oxford Properties team raised critical funds to support emergency response efforts to the New South Wales bushfires. Our New York team volunteers with a not-for-profit whose aim is to meet pressing community needs by mobilizing caring New Yorkers in volunteer service. In the U.K., we support organizations including the Rainbow Trust Children's Charities and hosted youth from underprivileged communities in our offices to provide a glimpse of the business world. And here in Ontario, employees from our head office take part in Volunteer Days, spending part of a day onsite to lend a hand. In 2019, we gave back to four local charities.

**Over the last few years, expectations of organizations to act responsibly, ethically and thoughtfully have increased. These expectations are not new to OMERS.**

We apply high ethical standards in our investing approach and we fully comply with the laws and regulations in the communities where our controlled investments operate. We support those local communities through the proper payment of taxes.

OMERS has long believed that well-run organizations with sound environmental, social and governance practices will perform better, particularly over the long term. In 2019, we adopted a refreshed Sustainable Investing policy, and we also made new commitments to address climate change. We have become a signatory to the Task Force on Climate-related Financial Disclosures. We have begun to introduce these disclosures in this Annual Report.

Our efforts in 2019 and our ongoing goal – which we acknowledge and embrace – is to link economic value to social value. We recognize we have this responsibility to our members, employers, stakeholders, employees and our partners and communities, promoting social sustainability for generations to come.

**We are pleased with our accomplishments in 2019 and over the past five years. Still, we are aware of the challenges that lie ahead. Our strategy sets out a realistic plan to face the future with optimism.**

**We seek the support of our members and our stakeholders as we navigate the complexities the Plan faces. Working together, we believe that we can continue to make OMERS a sustainable, affordable and meaningful defined benefit pension plan for you.**

TEAM WORKS

02

# UPDATE ON GOVERNANCE

# OUR GOVERNANCE MODEL

OMERS is governed by two corporations – OMERS Sponsors Corporation (SC) and OMERS Administration Corporation (AC) – each with a separate and distinct mandate described on our website at www.omers.com/governance. The two corporations and their Boards work together, closely and collaboratively, to meet a singular goal: to make OMERS a sustainable, affordable and meaningful defined benefit pension plan. The Boards have adopted a joint 2025 Strategy to ensure operational alignment and a joint risk management process to promote a common understanding of, and approach to, managing relevant risks.

This dual-Board, bicameral structure ensures broad input into decision-making by considering the interests of a large number of stakeholders and focused expertise in key areas, including Plan design, member and employer services and investments.

**We believe that effective and transparent governance is fundamental to achieving our respective mandates. We maintain high governance standards, and continue to evolve our governance model and practices.**

# JOINT BOARD ACTIVITIES

OMERS two Boards met together frequently throughout 2019.

Our Boards met for a joint strategy session, and subsequently, both Boards approved OMERS 2025 Strategy. The 2025 Strategy refreshes our 2020 Strategy, which we jointly approved in 2015. You can read more about the 2025 Strategy elsewhere in this Annual Report.

Through their respective Risk Oversight Committees, both Boards also collaborated on a process to focus on evaluating and updating the Plan's risk appetite statement.

Finally, we have a Joint Council, which is a subcommittee of both Boards; we use this council as a venue to address matters of mutual importance to AC and SC with respect to oversight and governance. The Joint Council met eight times during 2019.

# OMERS SPONSORS CORPORATION

## BOARD MEMBERSHIP CHANGES

Effective October 31, 2019, Ontario Public Service Employees Union (OPSEU) appointed Ms. Giulia Volpe as its representative, in replacement of Ms. Jennifer Richards. We welcome Giulia to the Board. Jennifer joined the SC Board effective January 1, 2019, and we thank her for her contributions during her tenure.

## COMMITTEE CHANGE

Effective January 1, 2019, the SC Board established a Risk Oversight Committee whose mandate is to recommend enhancements to the SC's risk management practices, and to collaborate with the AC's Risk Oversight Committee on overall Plan risk.

## BOARD EFFECTIVENESS REVIEW

In 2019 the SC Board conducted a Board Effectiveness Review with the goals of ensuring it has effective arrangements to meet contemporary governance standards, improving its governance regime and promoting effective decision-making – recognizing the SC Board members' fiduciary obligations to OMERS Sponsors Corporation, whose objective is to ensure the long-term sustainability of the Plan. Its Corporate Governance Committee met many times in 2019 to focus on this review, with support from management and from external governance and legal experts.

As a result of this review, the SC Board approved certain governance changes in November 2019. Below is a summary of those changes, which are effective as of January 1, 2020, unless otherwise stated. The SC Board believes that these changes will:

- Strengthen its governance framework;
- Support its commitment to OMERS members, employers and other stakeholders; and
- Help ensure that Board members bring the right skills and competencies to their roles on the Board.

In 2020, as part of OMERS regular bylaw review process, the SC will be completing an examination of the composition of both OMERS Boards.

### RESULTS OF SC BOARD EFFECTIVENESS REVIEW

**Updating Term Limits**

Effective January 1, 2021, SC Board member tenure will be subject to a limit of four 3-year terms. This change will ensure that new perspectives are being introduced and relevant skills are continuously being added to the SC Board.

**Enhancing a Skills-Based Committee Composition**

When changing committee composition, greater focus will be given to the skills needed to perform the mandates of that committee. Maintaining balanced representation remains a key consideration and is coupled with consideration of what skills and experience the committees need to perform their function.

**Modernizing Confidentiality Standards**

All materials going to the Board and discussions at the Board are to be treated as confidential. The Board, as a whole, will decide when information can be shared, consistent with the Board's stakeholder engagement program. This change is intended to ensure consistency and transparency of the information shared with Sponsors and other stakeholders.

## BOARD REMUNERATION CHANGES

SC is responsible under the OMERS Act to determine remuneration for Directors for both Boards. In 2019, in accordance with its bylaws and as part of its three-year review cycle, the SC Board reviewed remuneration with the assistance of an independent board compensation adviser. As a result of that review, the SC Board approved increases in board member compensation, effective January 1, 2020. These increases are summarized in the following pages.

## CEO CHANGE

Effective April 15, 2019, the SC Board appointed Mr. Michael Rolland as its new Chief Executive Officer.

Michael has driven success across many initiatives over his 20 years at OMERS, with a focus on creating value for all stakeholders. He has a deep and unique understanding of the mandates of both the AC and SC Boards and in his role with the SC Board he is committed to delivering on key responsibilities related to Plan design, contributions, strategy, stabilization reserves and valuation filing.

Michael has a diverse background in accounting, commercial finance and a broad range of industry sectors. He holds an Honours degree in Business Administration from the Richard Ivey School of Business at Western University, and is a Fellow of the Institute of Chartered Professional Accountants (FCPA) of Ontario.

Over a business career that has spanned more than 40 years, Michael has served on a variety of public, private, charity and community organization boards, both domestically and internationally.

**Enhancing the SC Board Nomination Process**

The SC will be more involved in the appointment process for new Board members. While Sponsors will continue to directly appoint and remove members, the SC will now conduct background checks and engage with Sponsors and proposed appointees to discuss the skills and experience required by the SC Board to meet its obligations as well as the commitments that board members should be prepared to make regarding education, development and participation.

**Updating the Removal Process of SC Board Members**

This change requires that Sponsors who are removing a Director before the end of their term now provide 30-days' notice and commit to reimbursing the SC for expenses the SC incurred in education and development for the board member being removed. The SC has the authority, on a vote of two-thirds of the board members, to remove a board member under certain limited circumstances, such as breach of the Code of Conduct or if a board member is charged or convicted of a criminal offense. Sponsors maintain the right to remove their appointee.

**Moving to a Chair/ Vice-Chair Model**

Effective January 1, 2021, the SC Board will be moving from a Co-Chair model to a Chair / Vice-Chair model. In the past, the Co-Chairs were nominated from and by their respective groups – employee representatives and employer representatives. In the new model, the Chair and Vice-Chair will be nominated and selected by the full Board, with due consideration for representation.

## ORIENTATION AND EDUCATION

Directors new to the SC Board participate in an orientation process, which includes a comprehensive discussion of the history and mandate of the corporation, OMERS strategy, business planning process and current programs.

Directors also participate in various educational programs and industry conferences, which are either approved or mandated by the organization. SC directors are also required to maintain certain educational requirements to stay current on key issues, and to continue to develop their knowledge and skills. OMERS Sponsors Corporation By-law No. 6 sets out the requirements and approval process for ongoing director development.

In 2019, eight OMERS Sponsors Corporation Board Directors attended up to four industry-related conferences and seminars, lasting from two to nine days.

## REMUNERATION

Set out in the table to the right are the retainers for Directors of the SC Board for 2019 and effective January 1, 2020. No other renumeration is provided to SC directors. For existing SC directors, compensation may be paid to the director or to the organization with which they are affiliated.

| | 2019 Annual Retainer | Effective January 1, 2020 |
|---|---|---|
| Co-Chairs | $80,000 | $85,000 |
| Committee Chair | $45,000 | $49,000 |
| All Other Directors | $38,500 | $42,000 |

SC Board Directors are reimbursed for reasonable and necessary expenses incurred in connection with carrying out the business of SC. These reimbursements relate primarily to travel and accommodation expenses incurred in connection with attendance at SC Board, committee or similar meetings. Directors are also reimbursed for travel, tuition and other expenses incurred while attending relevant conferences –or other professional and educational programs – within Canada and the continental U.S. Starting January 1, 2020, all SC Directors will also receive an annual technology allowance to compensate them for the expenses incurred related to acquisition, maintenance and licensing of technology related to their Board duties, as well as covering incidental expenses. This is a taxable benefit.

Travel time is not compensated.

Expenses may vary by year and by director for a variety of reasons, including the availability and location of programs, number of scheduled and ad hoc meetings attended, and the location of the director's primary residence.

## ATTENDANCE

In 2019, Directors attended anywhere from five to 60 meetings, with the median being 36. Director attendance is summarized in the "Reference" section of this Annual Report.

In 2019, Directors also attended up to seven other business events and meetings, including in-house education sessions, committee meetings of which they were not members, and other business meetings, as necessary. Numerous informal meetings and individual Director meetings with sponsor organizations are not tracked, but may occur monthly for some members of the SC Board.

# **BOARD MEMBERS** // OMERS SPONSORS CORPORATION

The SC Board comprises 14 members, half of whom are appointed by employer groups and half of whom are appointed by unions and associations, representing members.

BARRY BROWN
Board Co-Chair

FRANK RAMAGNANO
Board Co-Chair

DAN AXFORD

PAUL BAILEY

FREDERICK BIRO

JASON CHAN

PETER DEROCHIE

MARIANNE LOVE

CHARLIE MACALUSO

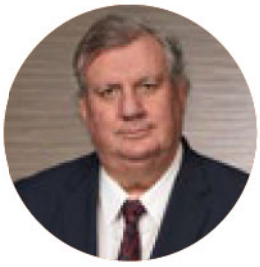
MARY MCCONVILLE

JOE PENNACHETTI

JENNIFER RICHARDS
(Until October 31, 2019)

SANDRA SAHLI

GIULIA VOLPE
(Effective October 31, 2019)



JOHN WEATHERUP

# OMERS ADMINISTRATION CORPORATION

## BOARD MEMBERSHIP CHANGES

Effective December 31, 2019, Mr. Bill Aziz and Mr. James Phillips each reached their term limits, and have retired from the AC Board. The AC Board thanks Bill and Jim for their contributions during their tenure. Ms. Debbie Fischer and Mr. Rajiv Silgardo have been appointed as their replacements, effective January 1, 2020.

These retirements led to the following changes in committee chair roles:

- Mr. Bill Butt has succeeded Bill Aziz in the role of Investment Committee Chair.
- Ms. Laurie Hutchinson has succeeded Bill Butt as Audit & Actuarial Committee Chair.
- Ms. Penny Somerville has succeeded Jim Phillips as Governance Committee Chair.

## COMMITTEE CHANGE

In 2019, the Governance Committee assumed oversight responsibility for Plan administration systems, technology strategy, and business continuity. These responsibilities had previously been in the mandate of the Board's separate Technology Committee, which has since been folded into the Governance Committee. As a result, Mr. Yung Wu and Ms. Charlene Mueller, who were members of the former Technology Committee, joined the Governance Committee, effective March 1, 2019. Mr. Michael Fenn, the Chair of the former Technology Committee, joined the Audit & Actuarial Committee effective March 1, 2019.

## CEO SUCCESSION

**On December 12, the AC Board announced the appointment of Mr. Blake Hutcheson as its new CEO, effective June 1, 2020, succeeding Mr. Michael Latimer, who will retire May 31, 2020. Michael is retiring after two decades with OMERS, including the last six years as CEO. The AC Board thanks Michael for his outstanding contributions during his tenure.**

Under Michael's leadership, OMERS assets have grown from $65 billion to $109 billion, growth of more than 60%. OMERS achieved a solid annual net return of 8% over this period, well above the Plan's discount rate, improving the Plan's financial position to near full funding. Over the same period, the organization successfully deployed $34 billion of capital as a result of its asset mix shift into private investment asset classes while expanding its global footprint and opening offices in Singapore, Sydney, Paris, Berlin, Boston and San Francisco.

Blake assumes his new role, having been with OMERS for ten years. The first eight and a half years he served as the CEO of Oxford Properties (an OMERS company) where he grew this business from being primarily a domestic operation to becoming a $50 billion, truly global leader in the real estate industry that returned an average of 12.5% during his tenure. Since April 2018, he has been the President and Chief Pension Officer at OMERS and has helped transform the Pension Services area within the organization, while carrying out responsibility for Strategy, Operations, Communications, Government Relations, Legal, and Data & Technology. Early this year, under his team's leadership, OMERS approved our 2025 Strategy, which will provide clear direction for the next five-year period. Blake has been a highly successful CEO for over 20 years and has served on more than 25 boards and committees of both public and private entities. He is a graduate of the University of Western Ontario, London School of Economics and Columbia University.

## ORIENTATION AND EDUCATION

Directors new to the AC Board participate in an extensive orientation process, which includes a comprehensive discussion of the history and mandate of the corporation, OMERS business and planning process, its strategy and current programs.

Directors also participate in various educational programs and industry conferences, which are either approved or mandated by the organization. Where possible, we develop in-house programs with external experts to educate the AC Board on matters relevant to its duties and mandate.

Directors are also required to meet certain educational requirements to stay current on key issues and to continue their professional development.

## REMUNERATION

Set out in the table to the right are the retainers for Directors of the AC Board for 2019 and effective January 1, 2020. Retainers are paid directly to Directors. No other remuneration is provided to AC Directors.

| | 2019 Annual Retainer | Effective January 1, 2020 |
|---|---|---|
| Chair | $165,000 | $185,000 |
| Committee Chair | $80,000 | $90,000 |
| All Other Directors | $65,000 | $75,000 |

AC Board directors are reimbursed for reasonable and necessary expenses incurred in connection with carrying out the business of AC. These reimbursements relate primarily to travel and accommodation expenses for attending AC Board, committee or other similar meetings. AC Directors receive an annual technology allowance to compensate them for the expenses incurred related to acquisition, maintenance and licensing of technology related to their Board duties, as well as covering incidental expenses. This is a taxable benefit.

Travel time is not compensated.

Expenses may vary by year and by director for a variety of reasons, including the availability and location of programs, number of scheduled and ad hoc meetings attended, and the location of the director's primary residence.

*Compensation for members of the Appeals Committee*

Board members who serve as members of the Appeals Committee are entitled to receive the applicable annual retainer payment plus an additional meeting fee for each day of attendance at a hearing, provided they are present for the full hearing while in session – regardless of the duration of the hearing on any given day. The Chair of the Appeals Committee earns $1,000 per day and all other committee members earn $750 per day.

## ATTENDANCE

AC Board member attendance at Board and committee meetings is summarized in the "Reference" section of this Annual Report.

# **BOARD MEMBERS** // OMERS ADMINISTRATION CORPORATION

The AC Board comprises 14 members nominated by sponsor organizations and appointed by the SC Board plus an independent Chair also appointed by the SC Board in a joint process with the AC Board.

GEORGE COOKE
Board Chair

BILL AZIZ
(Until December 31, 2019)

MONTY BAKER

DAVID M. BEATTY

DARCIE BEGGS

WILLIAM (BILL) BUTT

PAUL ELLIOTT

MICHAEL FENN

LAURIE HUTCHINSON

CLIFF INSKIP

CHARLENE MUELLER

JAMES PHILLIPS
(Until December 31, 2019)

PENNY SOMERVILLE

DAVID TSUBOUCHI

YUNG WU

Effective January 1, 2020

DEBBIE FISCHER

RAJIV SILGARDO

03

# MANAGEMENT'S DISCUSSION & ANALYSIS

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Funded Ratio

**97%**

2018: 96%

Net Return

**11.9%**

Benchmark: 7.5%

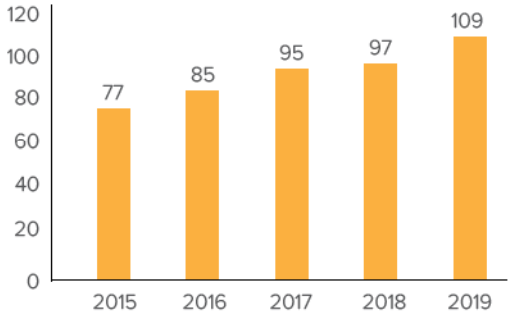
2018: 2.3%

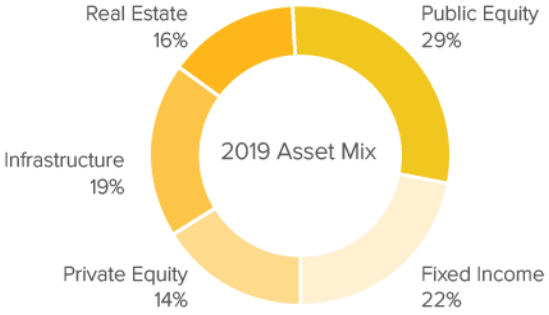
Discount Rate

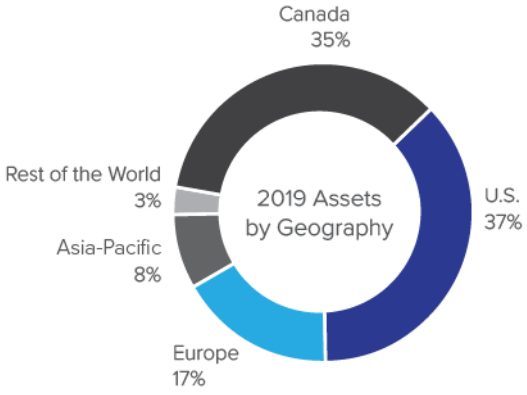
**5.90%**

2018: 6.00%

Net Assets ($ billions)



This Management's Discussion and Analysis ("MD&A") is the responsibility of the Management of OMERS Administration Corporation (AC) and OMERS Sponsors Corporation (SC). It contains Management's analysis of the OMERS Pension Plans' financial condition, operational results, and the environment in which the plans operate, and should be read in conjunction with the Consolidated Financial Statements. The AC Board of Directors has reviewed and approved the contents of this MD&A as at February 21, 2020. The SC management has reviewed and approved those sections that are relevant to SC's mandate.

In addition to historical information, this MD&A contains forward-looking statements with regard to Management's strategy, objectives, outlook and expectations. Forward-looking statements made in this section represent Management's views at the date of this report and Management does not undertake to update or revise any forward-looking statements as a result of new information, future events or otherwise. Many factors affect the plans' performance, such as changes in market conditions, interest rates, demographics and technological factors. Investment returns and values will fluctuate. Past performance is not a guide to or indicative of future results.

We use certain financial measures that are not based on Generally Accepted Accounting Principles (GAAP), including funding deficit, as key metrics in our financial reporting to enable our readers to better understand the performance of our business. Other non-GAAP financial measures that we use include investment results by asset exposures. These non-GAAP financial measures do not have any standardized meaning and may not be comparable with similar measures used by other companies or pension plans. They should not be viewed as an alternative to measures of financial performance determined in accordance with GAAP. For certain non-GAAP financial measures, there are no directly comparable amounts under GAAP. We have included reconciliations of certain financial measures from GAAP to non-GAAP financial measures in this MD&A.

Interests in the Plans are not and will not be offered or sold in the U.S., or to or for the account of U.S. persons, as defined by U.S. securities law.

# OVERVIEW OF OMERS PENSION PLANS

## ABOUT OMERS

Founded in 1962, OMERS is a jointly sponsored, defined benefit pension plan, with 1,000 participating employers ranging from large cities to local agencies, and over half a million active, deferred and retired members. Our members include union and non-union employees of municipalities, school boards, local boards, transit systems, electrical utilities, emergency services and children's aid societies across Ontario. Contributions to the Plan are funded equally by members and employers. OMERS teams work in Toronto, London, New York, Amsterdam, Luxembourg, Singapore, Sydney and other major cities across North America and Europe – serving members and employers, and originating and managing a diversified portfolio of high-quality investments in public markets, private equity, infrastructure and real estate.

The OMERS Pension Plans comprise the OMERS Primary Pension Plan (the Primary Plan or the Plan), the Retirement Compensation Arrangement (RCA) for the OMERS Primary Pension Plan, and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (Supplemental Plan).

# OMERS PRIMARY PENSION PLAN

The Primary Plan is a multi-employer, jointly sponsored pension plan, created in 1962 by an Act of the Ontario Legislature, whose members are mainly employees of Ontario municipalities, local boards, public utilities and non-teaching school board staff. The Primary Plan is governed by the OMERS Act, the Pension Benefits Act (Ontario) (PBA), the Income Tax Act (Canada) (ITA), and other applicable legislation. The benefit provisions and other terms of the Primary Plan are set out in the Primary Plan text. The Primary Plan consists of both the defined benefit component and the Additional Voluntary Contribution (AVC) component.

The Primary Plan is registered with the Financial Services Regulatory Authority of Ontario (FSRA) and the Canada Revenue Agency (CRA) under Registration #0345983.

Attributes of the defined benefit component of the Primary Plan include:

- Funding –The defined benefit component of the Primary Plan is funded by equal contributions from participating employers and members, and by the investment earnings of the Primary Plan assets. The AC determines the regulatory minimum funding requirements in accordance with the ITA and the PBA. The SC sets the actual contribution rates.
- Pensions – The normal retirement age (NRA) is 65 years for all Primary Plan members, except police officers and firefighters, who generally have a normal retirement age of 60 years. The Primary Plan is designed to provide lifetime defined benefit pensions. These pensions are calculated as a percentage of the member's earnings averaged over the highest 60 consecutive months, multiplied by years of credited service.
- Death Benefits – Death benefits are payable to a surviving spouse, eligible dependent children, designated beneficiary, or the member's estate upon the death of a member. Depending upon eligibility requirements, the benefits may be paid in the form of a survivor pension, lump sum payment or both.
- Escalation of Pensions – Pensions are increased for inflation through an annual adjustment equal to 100 percent of the increase in the average Consumer Price Index (CPI) over the prior year's average. This adjustment is subject to a limit of six per cent in any one year. If the increase in the average CPI exceeds the six per cent limit, the excess is carried forward to future years.
- Disability Pensions – A disability pension is available at any age to an active member who becomes totally disabled as defined by the Primary Plan. The pension is calculated using a member's years of credited service and the average annual earnings during the member's highest 60 consecutive months of earnings consistent with a normal retirement pension. Generally, disability pensions continue until normal retirement.
- Income Taxes – The Primary Plan is a Registered Pension Plan as defined in the ITA and is not subject to income taxes for contributions or investment income received. The operations of certain entities holding private equity, infrastructure or real estate investments may be taxable.

The AVC component of the Primary Plan enables members to make additional voluntary contributions on which the member receives the net investment return of the Primary Plan. For the AVC component of the Primary Plan, the liability of the Primary Plan is members' AVC contributions plus/minus the net investment rate of return of the defined benefit component of the Primary Plan.

In 2019, OMERS welcomed into the Primary Plan four City of Toronto legacy pension plans: The Corporation of the City of York Employee Pension Plan; The Toronto Civic Employees' Pension Plan; the Metropolitan Toronto Police Benefit Fund; and the Metropolitan Toronto Pension Plan. The members of these pension plans are all retired or are survivors of retired members.

## RETIREMENT COMPENSATION ARRANGEMENT (RCA) FOR THE OMERS PRIMARY PENSION PLAN

The RCA is an arrangement that provides pension benefits for Primary Plan members with earnings exceeding the amount that generates the maximum pension allowed by the ITA with respect to service after 1991. It is a separate trust arrangement and is not governed by the PBA and is not a Registered Pension Plan under the ITA. The RCA is governed by the OMERS Act, the ITA and other applicable legislation and is funded by equal contributions from participating employers and members and by the investment earnings of the RCA fund. Current and future contributions are determined annually to ensure that the existing RCA fund and future investment earnings are expected to be sufficient to pay projected benefits and expenses over the 20-year period following each actuarial valuation date. The RCA net assets available for benefits are invested and accounted for separately from the Primary Plan and the Supplemental Plan, and the accrued pension obligation of the RCA is valued separately from the Primary Plan and Supplemental Plan accrued pension obligations. Expenses of the RCA are paid from the cash flows of the RCA fund.

The RCA net assets were $162 million and the accrued pension obligations were $928 million at December 31, 2019, compared to $148 million and $851 million, respectively, at December 31, 2018.

## OMERS SUPPLEMENTAL PENSION PLAN FOR POLICE, FIREFIGHTERS AND PARAMEDICS

The Supplemental Plan became effective on July 1, 2008, pursuant to the requirements of the OMERS Act. The benefit provisions and other terms of the Supplemental Plan are set out in the Supplemental Plan text. The Supplemental Plan is registered with FSRA and with CRA under Registration #1175892.

Until March 31, 2024, unless the Supplemental Plan has sufficient funds based on the portion of contributions allocated for administrative expenses, any administrative costs of the Supplemental Plan are funded through a startup grant from the Province of Ontario.

Participation in the Supplemental Plan is effective only upon agreement between employee groups and their employer. As at December 31, 2019 and December 31, 2018, no such agreement existed and hence the Supplemental Plan had no assets and no members.

# UPDATE ON STRATEGY

## 2020 STRATEGY

**In 2015, the AC and SC developed a joint strategy (our "2020 Strategy"). It set out a five-year roadmap to ensure OMERS is resilient over the long term, advancing OMERS toward being a leading model for defined benefit pension plan sustainability.**

That Strategy addressed challenges related to:

- Changing demographic and workplace trends
- Longer life expectancy
- An increasingly uncertain economic environment creating pressure on investment returns
- Technology and other developments that could impact jobs in the Ontario municipal sector
- Legislative developments, including CPP enhancements that began to come into effect in 2019

Our 2020 Strategy addressed these challenges with four pillars of focus. We are pleased with our progress relative to our ambitions and present the following highlights from the past five years:

### PROTECTING OUR FUNDED STATUS

- We improved our funded status by 6% to 97% while reducing the discount rate by 35 basis points.
- We also advanced the discussion about funding risk between OMERS two boards and with sponsors, employers, and members.

See *Primary Plan Funded Status*.

### DELIVERING 7 – 11% NET AVERAGE ANNUAL INVESTMENT RETURNS

- We earned an average 5-year net annual rate of return of 8.5% and grew the Plan from $72 billion to $109 billion of net assets.
- We deployed $34 billion into infrastructure, real estate and private equity, in accordance with our strategic asset mix.
- We added credit as a new strategic asset class, building it to $18.3 billion and replacing interest-sensitive, long-term government bonds with a well-diversified, short duration, return-enhancing credit portfolio.
- We conducted an Asset-Liability study in 2019, focused on identifying an optimal long-term asset mix.

See *Investment Results* and *Asset Class Investment Performance*.

## BUILDING QUALITY RELATIONSHIPS

- We maintained high levels of member satisfaction above 90% annually. Our Member Services team connected with our members through more than one million phone calls, and provided 2,600 member information sessions.
- Our Employer Services team conducted more than 200 in-person information sessions for employers. In 2019, our employer satisfaction measured 92%.
- We also implemented in-person forums to engage leaders from our sponsors and other stakeholders on important matters.

## EVOLVING OUR CAPABILITIES AND BUSINESS MODEL

- We made great progress toward geographic diversification of our investment portfolio, building out our investment teams outside Canada, with a recent focus on Asia, through our office in Singapore.
- We did not meet the objectives we set out with respect to the schedule and costs for upgrading the IT systems that support pension administration, but are now on target to deliver a lower-risk solution.
- We have fortified our defenses against cyber intrusion.
- We made meaningful progress in evolving our culture and promoting inclusion and diversity among our teams.
- We significantly upgraded our capabilities in risk, member services, strategy, government relations, procurement, tax, economic research and data and technology management.
- We did not meet the cost targets set out in the original 2020 Strategy. We made deliberate choices to incur expenses which we consider are prudently delivering long-term value. See *Investment Management and Pension Administration Expenses* and *Risk Management*.

This is the last year in which we will report against our 2020 Strategy.

# 2025 STRATEGY

**We believe that the challenges we identified five years ago remain relevant today and will continue over our strategic planning horizon. We expect that existing uncertainty will be compounded by increased government changes and geopolitical instability; high investment valuations; increasingly competitive markets; and interest rate uncertainty. We anticipate that technological developments and ESG factors will lead to rapid disruption across industries.**

Throughout, our focus remains on making OMERS a sustainable, affordable and meaningful defined benefit pension plan.

It is in this context that our two Boards refreshed our strategy for the next five years (the "2025 Strategy"). This refreshed strategy continues many of the same priorities as its predecessor, with increased focus on Plan Design and Funding. Our five key areas of focus are discussed below. Our focus areas fall into two broad categories – Financial Resiliency and Institutional Resiliency.

## FINANCIAL RESILIENCY

**PLAN DESIGN** As we focus on meeting stakeholders' needs and sustainability, we will look for ways to modernize, simplify and grow the Plan.

**FUNDING** We plan to manage relevant levers to ensure the Plan's long-term financial health. This includes developing a joint funding framework and funding management strategy. We also intend to continue conducting regular Asset-Liability studies, and to continue to lower our discount rate.

**INVESTMENT** We will continue to deliver against our total portfolio strategy across our diverse investments in the context of our liabilities, actively incorporating ESG factors, while improving global diversification and expanding our strategic partnerships.

## INSTITUTIONAL RESILIENCY

**ENGAGEMENT** We aim to improve stakeholder trust and understanding, primarily by advancing our pension services delivery model, our government relations initiatives and continuing to engage with sponsors.

**OPERATIONS** We will continue to advance our capabilities through a dedicated focus on talent, data and technology, and costs.

# PRIMARY PLAN FUNDED STATUS

**The funded ratio is an indicator of the long-term financial health of the Plan. In 2019, the funded ratio increased to 97%, from 96% in 2018.**

| December 31, | 2019 | 2018 |
|---|---|---|
| Funded ratio on a smoothed basis | 97% | 96% |
| Discount rate | 5.90% | 6.00% |
| Pension obligations ($ billions) | $106.4 | $99.1 |
| Funding deficit ($ billions) | $3.4 | $4.2 |
| Net assets on a smoothed basis ($ billions) | $103.0 | $94.9 |
| Unrecognized investment returns ($ billions) | $4.9 | $1.4 |

The funded ratio is the relationship of Plan assets to pension obligations on a going-concern basis. The deficit represents the difference between the pension obligations and the smoothed value of assets. Plan assets are calculated by smoothing investment returns – above or below the Plan's discount rate – over a five-year period. By smoothing asset values, contribution rates can be set, and benefits designed, without putting undue emphasis on short-term investment performance and volatility. At the end of 2019, investment returns not recognized in the funding deficit were $4.9 billion compared to $1.4 billion in 2018, which will be recognized over the next four years. In 2019, we assumed into the Primary Plan four City of Toronto legacy pension plans. These plans added 4,200 members to the Plan, and transferred assets and liabilities.

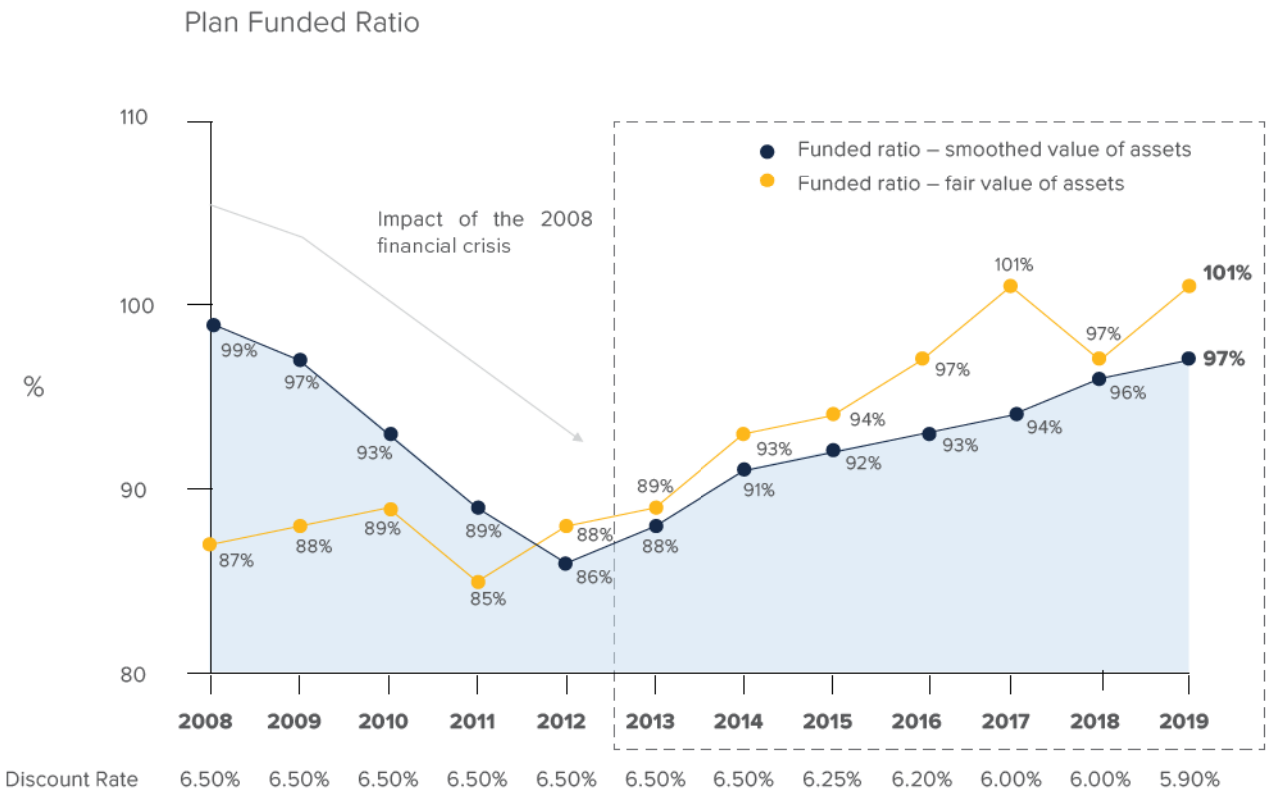
The funded status improved in 2019 due to the net result of the following factors:

| Funded Ratio % | | Deficit billions $ |
|---|---|---|
| 96% | **Beginning of year** | $(4.2) |
| n/a | Interest on deficit | (0.3) |
| 1 | Contributions from members and employers to pay down the deficit | 0.6 |
| 2 | Recognized investment returns in excess of the discount rate | 2.1 |
| — | Primary Plan experience and other factors | (0.1) |
| (2) | Reduction in the discount rate by 10 basis points | (1.5) |
| 97% | **End of year** | $(3.4) |

The Plan's funded status, on a smoothed basis, has improved for the seventh consecutive year mainly due to smoothed investment returns in excess of the discount rate, together with member and employer contributions. We remain focused on improving the funded status while reducing the discount rate over time, to reflect the Plan's level of funding risk.

There were no changes to contribution rates or benefit accruals in 2019. Contribution rates will remain unchanged in 2020, and pension payments will increase 1.89% for inflation, consistent with the Plan's text.

The following chart tracks the funded status of the Plan over the past 10 years. In 2019, the funded ratio based on the fair value of assets increased four percentage points from 97% to 101%, principally because the net return was above the discount rate.



# RISK MANAGEMENT PHILOSOPHY

**We define risk management as the prudent identification, measurement and management of risk. Our risk management process, through our "risk appetite statement", defines our risk profile both quantitatively and qualitatively. Management and the Boards of Directors rely on this risk management process to manage the Plan's funded status.**

Overall Plan risk is commonly referred to as funding risk – the risk that OMERS will need to increase contributions and/or reduce benefits. We break down our risk using a risk framework comprised of four key risk categories: Pension Risk; Investment Risk; Operational Risk; and Emerging Risk. OMERS governance plays an instrumental role in supporting the risk framework.

These risks are described in the Risk Management section of this MD&A.

Using our risk appetite statement, we measure our risk profile against these risk categories. The Plan's level of funding risk today is elevated, primarily due to increasing plan maturity, decreasing investment return expectations and adverse demographic trends. As a result, we forecast that contribution rates will remain at their current levels for the foreseeable future.

# MANAGING THE PLAN'S LONG-TERM FINANCIAL HEALTH

OMERS objective is to make the Primary Plan a sustainable, affordable and meaningful defined benefit pension plan. This requires OMERS to deliver an appropriate range of benefits within an acceptable range of costs, across generations and through both favourable and adverse circumstances, while protecting the Plan's funded status. Three levers are available to manage the Plan's funded status:

1. contribution rates 2. benefit design 3. investment returns

OMERS is committed to taking a strategic and co-ordinated approach to using these three funding levers so that decisions support long-term sustainability objectives, and so that those decisions are fair, balanced, and informed by robust risk management practices.

The SC conducted the Comprehensive Plan Review in 2018. In 2019, the SC Board continued its efforts to enhance the long-term health of the Plan by reviewing approaches for sharing risk across broader groups of Plan members.

## INCREASING PLAN MATURITY

A declining active membership base relative to the retired member population is known as "plan maturity." This maturity is caused by a variety of factors, including increasing longevity, a decline in the ratio of active to retired members, and retirement patterns. OMERS is a maturing plan.

Since all Plan risk is borne by active members and employers, this maturity means that the cost of funding the Plan is increasingly concentrated in a relatively smaller group of active members, which reduces our capacity to bear risk.

Further, as the ratio of active to retired members continues to decline, annual defined benefit payments exceed annual defined benefit contributions, so the Plan must increase its reliance on investment income. This makes the Plan more vulnerable to economic downturns.

The ratio of active members to retired members is a common measure of Plan maturity. Our ratio has declined to less than 2:1 at the end of 2019. It is expected to reach less than 1:1 in the late 2030s.

Anticipating and managing the impact of plan maturity better positions the Plan to absorb adverse events.

## DECREASING INVESTMENT RETURN EXPECTATIONS

The Plan has experienced strong investment returns in recent years – except for in 2018, when public market returns were negative and our net investment return was lower than our discount rate. However, financial market volatility, lower future growth rates, and a high level of competition for asset classes all impact investment performance, and predicting future investment returns is very difficult because of these impacts.

Looking ahead, we anticipate that global growth will slow, interest rates will remain low and future investment returns will be lower than in the past 10 years. Should investment returns underperform long-term expectations or the discount rate, the Plan could require increased contributions and/or decreased benefits to fund the resulting deficit.

This increases the Plan's funding risk.

## ADVERSE DEMOGRAPHIC EXPERIENCE

Demographic experience includes unexpected changes in life expectancy (such as increased longevity), salary increases, and retirement and termination trends of members. If adverse demographic experience leads to actuarial losses, which result in a change to actuarial assumptions, we would be required to increase the valuation of our pension obligations and our funding requirements. Life expectancy, in particular, has steadily increased over time. This means that retirees collect pensions for longer periods, which increases the pension liabilities and funding risk.

We monitor our demographic experience against actuarial assumptions annually, and conduct a detailed experience study at least once every five years, with the most recent study completed in 2018.

## MANAGING THE PLAN'S RISK PROFILE

The Boards of Directors manage the Plan's risk profile with the following tools:

- the funding management strategy
- protocols for setting the discount rate
- contribution rate studies
- setting the strategic asset mix through periodic asset-liability studies
- demographic studies; and
- periodically evaluating plan design

Two important tools are the funding management strategy and the discount rate.

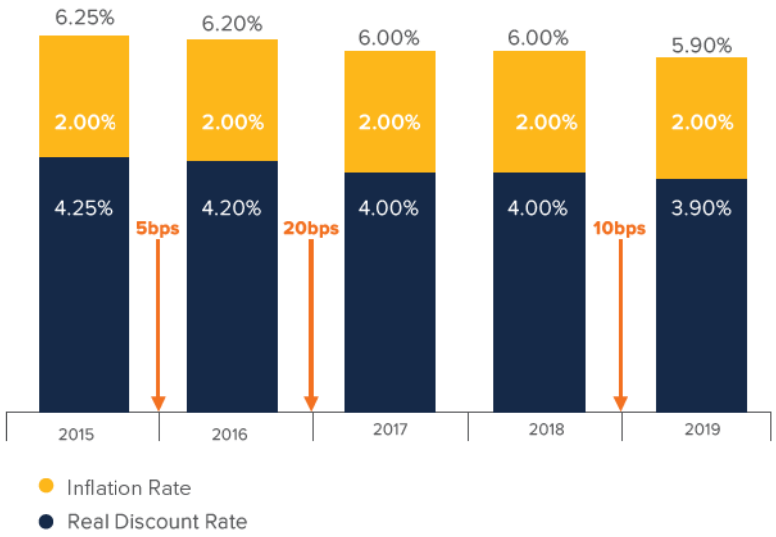
## DISCOUNT RATE

The discount rate is the interest rate used to determine the Plan's pension obligation and minimum contribution rates. As such, it plays an important role in managing the Plan and addressing risk over the long term.

The discount rate is comprised of the following components:

a) the real discount rate (before inflation), which reflects expectations of future real investment returns from the Plan, less a margin to reflect risk; and

b) an assumption for future inflation.



In 2019, we took steps to manage our risk profile and lowered the real discount rate. The discount rate as at December 31, 2019 was 5.90%, compared to 6.00% as at December 31, 2018. This decrease is the result of reducing the real discount rate by 10 basis points from 4.00% to 3.90%, reflecting the increasing risks the Plan is facing. The assumption for future inflation was 2.00% for both 2019 and 2018.

The discount rate is an important input in managing the Plan and addressing its funding risk over the long term. Decreasing our discount rate helps to mitigate investment risk, and increases the normal cost and the Plan's pension obligation. Each five-basis-point reduction in the real discount rate, as at December 31, 2019, would increase the normal cost by approximately 0.2% and the pension obligation by $0.8 billion.

To protect against Plan funding risk factors, we continue to target reductions in the real discount rate over time. Going forward, consistent with our 2025 Strategy, we intend to reduce the discount rate by a minimum of five basis points each year, to within a range of 3.50% to 3.75% by 2025, and lower if possible.

Each year, the AC tests the reasonableness of the Plan's discount rate to ensure it contains sufficient margins, in accordance with our risk appetite, and to protect the Plan from adverse experience over the long term.

# RCA FUNDING

The RCA's funding target is to help ensure that the existing RCA fund, projected contributions and projected investment earnings are sufficient to pay for benefits and expenses for a period of 20 years following each valuation date.

The RCA's primary risk is that contributions collected will be insufficient to meet its 20-year funding target. RCA contributions are dependent on Primary Plan contribution rates and the number of RCA active members. The RCA is also subject to increasing plan maturity, and its associated risks.

The RCA's funding model is resilient to lower-than-expected investment returns because of its 20-year funding horizon.

OMERS continually monitors these risks.

# INVESTMENT RESULTS

Net Return

**11.9%**

**Benchmark:** 7.5%
**2018:** 2.3%
**3-year average:** 8.5%

Net Investment Income

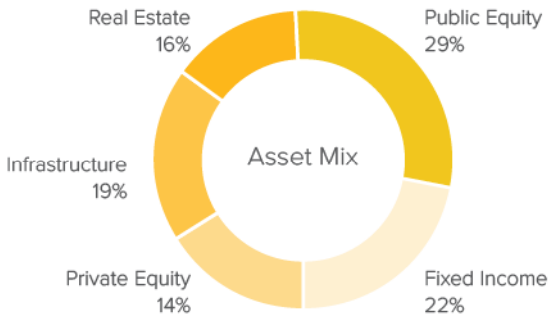
**$11.4** billion

**2018:** $2.4 billion

Net Assets

**$110.8** billion

**2018:** $98.7 billion




## ECONOMIC ENVIRONMENT

Public equity markets began 2019 at a low point, after a significant correction at the end of 2018. Concerns about trade tensions, geopolitical tensions and an impending recession were prevalent. However, these gave way to a more optimistic outlook as global monetary policy, led by the U.S. Federal Reserve shifted from tightening to easing with three interest rate cuts during the year. Yields fell in multiple countries, reflecting the renewed commitment of central banks to underpin one of the longest global expansions in history. Meanwhile, labour markets globally continued their robust performance, supporting household spending and offsetting the weakness in business investment, trade, and manufacturing resulting from escalating tariffs.

Public markets finished 2019 with exceptional full year returns, more than recovering the losses from 2018. Broad public equity indices generated the highest returns in the last decade, posting double digit returns in 2019. Fixed income indices generated positive returns driven by a downward shift in the yield curves and credit markets benefited from narrowing spreads.

| Indices 2019 Performance | 2019 Return |
|---|---|
| **EQUITIES** | |
| S&P 500 Index (US) | 31.5% |
| S&P TSX Composite (Canada) | 22.9% |
| MSCI World Equity (Local) | 27.3% |
| **BONDS** | |
| FTSE TMX Canada Universe Bond Index (CAD) | 6.9% |
| Barclays US Corporate High Yield Index (US) | 14.3% |

# RESULTS

In 2019, the Primary Plan had a return, net of expenses, of 11.9%, or $11.4 billion, compared to a benchmark of 7.5%. All asset classes generated positive returns. The 2019 net return outperformed our benchmark primarily due to very strong public equity appreciation. We measure our performance against an absolute return benchmark approved by the AC Board before or at the beginning of each year. Our goal is to earn stable returns that meet or exceed our benchmarks.

Investment returns for the Primary Plan and RCA for 2019 and 2018 are included in the table below.

| For the years ended December 31, | 2019 | | | 2018 | | |
|---|---|---|---|---|---|---|
| | Net Investment Income $ millions | Net Rate of Return % | Benchmark % | Net Investment Income $ millions | Net Rate of Return % | Benchmark % |
| **Fixed Income** | | | | | | |
| Inflation-Linked Bonds | $ 227 | 7.1 % | | $ (13) | (0.4) % | |
| Government Bonds | 60 | 1.2 | | (65) | (0.6) | |
| Credit [2] | 1,331 | 8.0 | | 577 | 3.1 | |
| **Public Equity** | 5,837 | 20.3 | | (2,859) | (8.3) | |
| **Cash and Short-Term Instruments** | 199 | n/a | | 94 | n/a | |
| **Total Public Investments** | $ 7,654 | 16.4 % | 6.0 % | $ (2,266) | (4.6) % | 6.0 % |
| **Private Equity** | 637 | 4.6 | 11.0 | 1,601 | 13.5 | 11.2 |
| **Infrastructure** | 1,708 | 8.7 | 7.9 | 1,794 | 10.6 | 8.6 |
| **Real Estate** | 1,439 | 8.3 | 7.9 | 1,288 | 8.7 | 8.4 |
| **Total Primary Plan Fund** | $ 11,438 | 11.9 % | 7.5 % | $ 2,417 | 2.3 % | 7.3 % |
| **RCA Investment Fund [1]** | $ 17 | 20.9 % | 21.5 % | $ (1) | (1.6) % | 0.1 % |

[1] Excludes the RCA refundable tax balances with the Canada Revenue Agency. The RCA net rate of return including the refundable tax balance in 2019 is 11.1%, compared to (0.8)% in 2018.

[2] Credit includes private credit investments. These assets have observable public market comparables and are reported with public investments.

# ASSET ALLOCATION AND EXPOSURE

We mitigate risk and target strong, consistent returns by purchasing high-quality assets, diversified across asset type, economic sector and geographic market. We have Board-approved target asset allocations across our asset classes which are designed to deliver returns over the long term to meet pension obligations. Fixed income investments include securities in inflation-linked bonds, government bonds and credit. Equity investments include both public and private equities, either through the purchase of instruments directly, or through the use of derivatives. We also invest in real assets, which include infrastructure and real estate, selected specifically for their ability to provide more predictable returns and cash flows.

During 2019, we conducted an Asset Liability Study. As a result, the AC Board approved a new long-term asset mix for OMERS as summarized in the chart below:

| | 2025 Strategy | 2020 Strategy |
|---|---|---|
| **Fixed Income** | **30%** | **46%** |
| Bonds | 10% | 29% |
| Credit | 20% | 17% |
| **Equities** | **45%** | **36%** |
| Public Equities | 30% | 22% |
| Private Equities | 15% | 14% |
| **Real Assets** | **45%** | **41%** |
| Infrastructure | 22.5% | 23% |
| Real Estate | 22.5% | 18% |
| **Short-Term instruments** (net cash and equivalents and including economic leverage) | **(20)%** | **(23)%** |

Net investment assets exposure is set out in the table below. To arrive at the Plan's ultimate exposure by asset class, the asset mix includes derivative exposures. The inclusion of derivative exposures are reflected in each asset class, with an offset to economic leverage. Economic leverage is the difference between the exposure to an asset class and the fair value of the derivative in the asset class. Net investment asset exposure at the end of 2019 was $110.8 billion ($98.7 billion, 2018), including administered funds of $1.6 billion ($1.4 billion, 2018), less the non-investment-related items of $(0.1) billion ($(0.1) billion, 2018).

| As at December 31, | 2019 | | 2018 | |
|---|---|---|---|---|
| | Net Investment Asset Exposure $ millions | Asset Mix % | Net Investment Asset Exposure $ millions | Asset Mix % |
| **Fixed Income** | | | | |
| Inflation-Linked Bonds | **$ 2,743** | **2.5 %** | $ 3,829 | 3.9 % |
| Government Bonds | **3,468** | **3.0** | 5,692 | 5.7 |
| Credit | **18,310** | **16.5** | 18,721 | 19.0 |
| | **24,521** | | 28,242 | |
| **Equities** | | | | |
| Public Equity | **31,992** | **28.9** | 32,681 | 33.1 |
| Private Equity | **15,702** | **14.2** | 14,243 | 14.4 |
| | **47,694** | | 46,924 | |
| **Real Assets** | | | | |
| Infrastructure | **21,348** | **19.3** | 17,921 | 18.2 |
| Real Estate | **17,493** | **15.8** | 18,060 | 18.3 |
| | **38,841** | | 35,981 | |
| **Short-Term Instruments** | | | | |
| Cash | **12,413** | **11.2** | 8,806 | 8.9 |
| Economic Leverage | **(12,661)** | **(11.4)** | (21,243) | (21.5) |
| | **(248)** | | (12,437) | |
| **Total** | **$ 110,808** | **100.0 %** | $ 98,710 | 100.0 % |

Our net investment asset exposure of $110.8 billion at the end of 2019, increased $12.1 billion from $98.7 billion at the end of 2018.

One element of our investment strategy is to use economic leverage to buy public assets when markets are depressed and sell assets when prices increase. Public equity prices suffered a sharp decline in 2018, whereas both public equities and fixed income assets enjoyed strong gains in 2019. As public markets advanced in 2019, we realized gains and reduced exposures to public equities and fixed income with a corresponding reduction to economic leverage. Our cash position also increased due to realized gains on asset sales and realized foreign currency hedging gains as the Canadian dollar strengthened relative to our foreign currency exposures in 2019. As a result, we decreased economic leverage, and our Short-Term Instruments were $(0.2) billion at the end of 2019, compared to $(12.4) billion at the end of 2018.

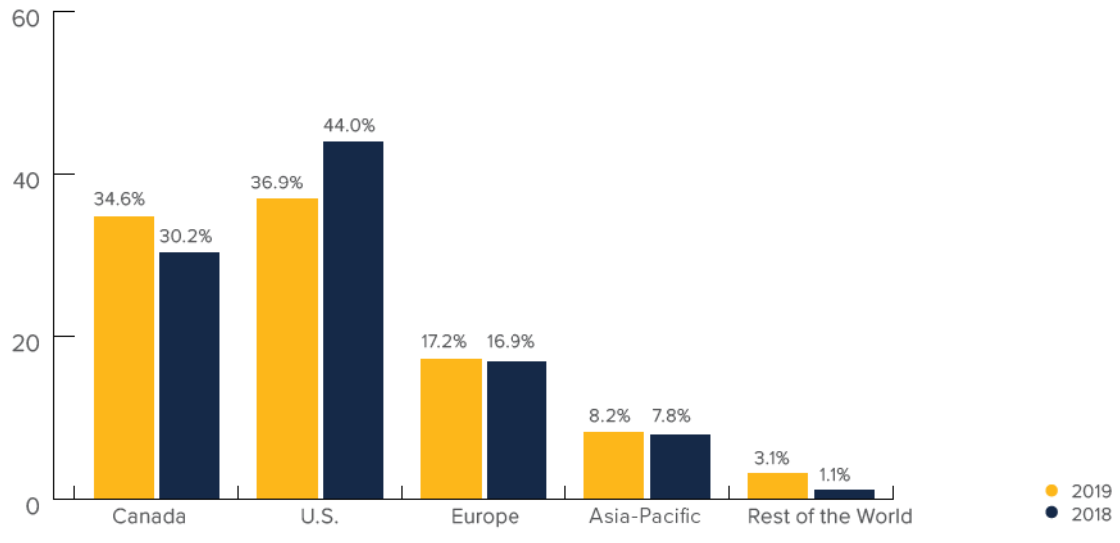
Four years ago, we began to significantly increase our exposure to the credit asset class which now stands at $18.3 billion at the end of 2019. We believe that rotating capital away from low-yielding, long-dated government bonds into higher-yielding credit investments provides for a better return on risk in the current low interest rate environment.

During 2019 we continued deploying incremental capital in infrastructure, real estate and private equity, to improve the level and stability of returns. Over a five-year period we have deployed $34 billion into these asset classes.

## COUNTRY EXPOSURE

The chart below presents the Plan's asset exposure by country. While Canada continues to offer strong, long-term investment opportunities, prudence and related risk-management practices make it appropriate to diversify investments across global markets with different growth profiles.

Total Fund Exposure[1] as at December 31,




[1]Exposures are presented net of financial leverage and before economic leverage.

## CURRENCY EXPOSURE

To protect our investments from the impact of foreign currency exchange volatility, our approach has been to hedge a large proportion of our exposure to foreign currencies. At December 31, 2019, 92% of currency exposure on our foreign investments was hedged to Canadian dollars compared to 95% at the end of 2018. During 2019, foreign exchange losses of $3.3 billion were offset by hedging gains of $3.1 billion. This compared to foreign exchange gains of $4.1 billion, which were offset by hedging losses of $4.1 billion in 2018.

In 2019, we protected 3.1% of our net return through currency hedging, as a result of the Canadian dollar's appreciation relative to other major currencies. Absent currency hedging, our 2019 net return would have decreased to 8.8% compared to the actual net return of 11.9%. Absent currency hedging, our 2018 return would have increased to 6.6%, or 4.3% higher than the actual net return of 2.3%, as a result of the Canadian dollar's depreciation relative to other major currencies.

## INDUSTRY EXPOSURE

The OMERS portfolio remains highly diversified across industries. The table below shows OMERS investment exposure by industry, net of financial leverage and before deducting economic leverage.

| As at December 31, | 2019 | 2018 |
|---|---|---|
| Financials | **18.6 %** | 18.1 % |
| Real Estate | **16.6 %** | 16.5 % |
| Industrials | **10.4 %** | 10.3 % |
| Utilities | **10.3 %** | 9.5 % |
| Cash and Cash Equivalents | **10.1 %** | 5.6 % |
| Health Care | **7.6 %** | 7.1 % |
| Information Technology | **6.5 %** | 6.1 % |
| Government | **5.5 %** | 8.2 % |
| Energy | **5.1 %** | 5.4 % |
| Consumer Discretionary | **2.9 %** | 4.8 % |
| Communication Services | **2.8 %** | 2.9 % |
| Consumer Staples | **2.1 %** | 3.1 % |
| Materials | **1.5 %** | 2.4 % |
| **Total** | **100.0 %** | 100.0 % |

# INVESTMENT MANAGEMENT AND PENSION ADMINISTRATION EXPENSES

Building a diversified portfolio of high-quality investments requires highly skilled talent with knowledge and experience to deliver strong long-term returns. We believe that in-house management generally creates better value than external management. We selectively use third-party managers to obtain access to specialized investment products and markets. Over the last several years, we have increased global diversification of the portfolio, expanded asset allocation into private assets and introduced credit as a new strategic asset class. The objective of these decisions is to optimize investment returns. In doing so, we accept the related costs which will vary depending on many factors, including actual performance results and asset mix.

Internal investment management expenses were $581 million in 2019, compared to $540 million in 2018. Increased investment expenses are mainly driven by strong performance in our public investments and overall plan, resulting in higher pay-for-performance costs. These higher costs were partially offset by lower pay-for-performance costs in private equity due to lower performance than 2018.

In addition to internal investment management expenses, we incurred expenses for external manager performance and pooled fund fees of $111 million in 2019 compared to $99 million in 2018. Higher external manager and pooled fund fees were due to increased allocation and performance. Together, these items represent a Management Expense Ratio of 67 basis points in 2019, compared to 66 basis points in 2018.

For several years we have been developing a replacement for our Pension Administration System. In 2019, we performed an assessment to determine whether to complete the development of a single comprehensive platform or whether an alternate option was available. We determined that the life of our legacy system could be extended due to advances in technology architecture and maturing approaches for renovating older computer systems which we expect will enable us to deliver new, more resilient functionality quicker and at a lower overall cost. Accordingly, we have shifted from developing a single comprehensive platform to iteratively modernizing our existing system. As a result of the change to a lower risk approach, we charged $92 million to Pension Administration Expenses. In 2019, our Pension Administration Expenses increased to $190 million, compared to $93 million in 2018.

We have a system of controls designed to ensure that costs are managed prudently, including a Board approved budget for investment management and pension administration expenses, supplemented by quarterly reporting on expenses incurred and forecast.

# SUSTAINABLE INVESTING

OMERS has a responsibility to invest and manage the Plan's funds to meet our long-term obligations. We do this by investing in a portfolio of diversified, high-quality assets around the globe. As a long-term investor, we try to identify and address changes in the world around us that will or may affect the value or risk of our investments – including environmental, social and governance factors.

We specifically recognize that climate change and the expected transition to a lower-carbon global economy could have a significant long-term impact on the companies and assets in which we invest. We have therefore endorsed the recommendations of the *Task Force on Climate-related Financial Disclosures* (TCFD), which create a framework for consistent disclosure related to climate change. In the following pages we discuss our approach to sustainable investing, including specific descriptions of how our approach addresses climate change. Our additional TCFD-compliant disclosures follow.

## GOVERNANCE

The AC Board has approved OMERS Sustainable Investing Policy. The Investment Committee of the AC Board is responsible for overseeing our approach to sustainable investing. Board members receive regular reporting on our sustainable investing practices.

We have also established a Sustainable Investing Committee, overseen by our Senior Executive Team, to lead our integrated approach. That Committee's membership includes our Chief Investment Officer; our Executive VP & General Counsel; our VP of Sustainable Investing; decision-makers from each of our investing business units; and representatives from finance, risk, legal and communications. Its mandate is to:

- stay current on emerging trends, issues and best practices relevant to ESG matters;
- support and guide others across OMERS on ESG matters;
- report to the Investment Committee, Senior Executive Team, and other stakeholders; and
- recommend amendments to our Sustainable Investing Policy, ESG Guidelines and Climate Change Guidelines.

**For more detail on our sustainable investing activities, including current information on our portfolio, visit www.omers.com/si.**

# OUR PRINCIPLES

It has been our long-held belief that well-run organizations, with sound environmental, social and governance (ESG) practices will perform better, particularly over the long term.

This belief is formalized in our Statement of Investment Policies and Procedures, and is described in our Sustainable Investing Policy. This policy applies to assets across OMERS investment portfolio. Central to this policy is our commitment to becoming a leader in sustainable investing.

Our approach to sustainable investing is grounded in four overarching principles – integration, engagement, collaboration and adaptation. All of OMERS investment and asset management teams must abide by these principles in their respective investment processes.

## INTEGRATION

We integrate ESG factors into our investment analyses, asset management practices, and decision-making processes. This means that the investment teams pay careful attention to evaluating both qualitative and quantitative factors in making investment and asset management decisions. These processes are tailored to their type of asset to ensure that important and relevant factors are considered. Our investment approval processes require specific discussion of material ESG risks and opportunities. These factors include climate change, labour practices, inclusion and diversity practices, Indigenous Rights and board composition, among others.

**Integrating Climate Change**

When the impact of climate change is considered material to a proposed investment, our teams analyze the potential impacts to value or to risk – whether positive or negative. They involve internal or external experts as necessary.

Each of our asset class teams has developed assessment procedures on climate change tailored to their unique investing approaches and strategies.

We believe that as a large institutional investor, we can influence sustainable business practices among our investee companies. We therefore believe that engagement is more impactful than exclusion or divestment. However, we believe there are instances where excluding an industry is appropriate. We have established a set of criteria to help evaluate whether a particular industry should be considered for exclusion. Our Senior Executive team considers both risks posed by ESG factors and OMERS fiduciary duty. Based on our criteria, we exclude the following investments:

- civilian firearms manufacturers;
- cluster munitions manufacturers; and
- tobacco producers and manufacturers.

## ENGAGEMENT

Our investment teams actively promote sustainable business practices and long-term perspectives across our investment portfolio through direct engagement with management and Boards of Directors. Investors in publicly traded equities have voting rights through proxies; we always exercise these rights and vote according to our Proxy Voting Guidelines, which are reviewed and updated regularly.

**Engaging on Climate Change**

We use our influence to address climate change risks specifically through our governance rights and proxy voting activities.

When investing in private assets we typically acquire governance rights, including board seats. We exert our board-level influence to encourage the investee company to maintain and build on sustainable business practices and long-term thinking.

Through this active governance, OMERS influences material ESG-related practices in our investees' strategies and operations.

## COLLABORATION

We collaborate with like-minded organizations to exchange information and advocate for better transparency and performance on relevant standards, practices and regulations. We have partnered with international organizations which promote collaboration, action and knowledge-sharing on ESG matters, including the Canadian Coalition for Good Governance (CCGG), the Global Risk Institute (GRI) and the Investor Leadership Network (ILN).

**Collaborating on Climate Change**

Our endorsement of TCFD disclosure standards demonstrates our commitment to working with like-minded organizations on climate change.

OMERS is a member of the ILN, which is committed to accelerating the implementation of the TCFD, among other initiatives.

OMERS is an active member of the A4S - Accounting for Sustainability, a charity established by the Prince of Wales and whose aim is to make sustainable decision making business as usual.

**Adapting with Respect to Climate Change**

Like other institutional investors, we are continually seeking ways to measure climate risk across a broad, diversified portfolio.

We are engaging in carbon footprinting exercises and developing an approach to conduct scenario analyses that will help us determine the Plan's resiliency to effects of climate change.

## ADAPTATION

We recognize that the sustainable investing landscape is rapidly evolving, and so we commit to regularly enhancing our capabilities and practices. We want to ensure that we remain transparent, and that our approach remains relevant and effective over time. As we adapt, we will post updates to the Sustainable Investing section of our website www.omers.com/si.

We believe that paying careful consideration to sustainable investing is important to delivering returns for the long-term sustainability of the Plan.

# CLIMATE-RELATED DISCLOSURES

We have endorsed the Task Force on Climate-related Financial Disclosures (TCFD) because we believe that climate change presents both long-term risks and opportunities for the Plan's financial returns. Our TCFD-aligned disclosures follow.

TCFD | TASK FORCE ON CLIMATE-RELATED FINANCIAL DISCLOSURES

**TCFD is a global standard to promote the enhancement of climate-related disclosures by corporations and other entities. Its framework recommends disclosing details about an organization's governance, strategy, risk assessment and metrics and targets related to climate change.**

## GOVERNANCE

The roles of the AC Board, OMERS Senior Executive Team and our Sustainable Investing Committee in exercising oversight of Sustainable Investing matters is highlighted in the Sustainable Investing section. Their oversight includes matters related to climate change.

## STRATEGY

Climate change presents both physical and transition risks to our investment portfolio. Physical risks include the risk of loss due to extreme weather events or longer-term shifts in climate patterns. Transition risks include changes in government policy, regulation, consumer preferences and technology, which may increase the costs of certain assets (e.g. carbon pricing) or their marketability (e.g. stranded assets). These changes may impact the value of our investments.

OMERS currently invests in the development and generation of clean energy and, increasingly, in the traditional energy industry. This sector remains important to the global economy, and we believe that responsible and long-term investors play a vital role in providing leadership on the cleaner and safer production and transportation of traditional energy.

Attractive investment opportunities continue to arise as renewable, low-carbon and next generation energy projects gain traction. New technologies – even new industries – could evolve as the world transitions and adapts.

Our strategy for addressing climate change appears in the Sustainable Investing section.

## RISK MANAGEMENT

OMERS has a formal risk framework which governs our approach to identifying and managing risks, including those related to ESG and climate change. We have established a Climate Risk Working Group, comprised of risk professionals from each investment team and representatives from our Sustainable Investing Committee.

Our investment teams assess risk at the underwriting and asset management level with assistance from internal or external advisers where necessary. Our investment approval process includes separate risk reporting on items such as climate change, if it could materially impact the investment opportunity.

## METRICS & TARGETS

In our real estate business, Oxford Properties has established metrics and targets related to climate change as described below. We continue to evaluate metrics and tools that may help us assess climate risk and opportunities across our broad investment portfolio, including carbon footprinting.

### HIGHLIGHTS FROM OXFORD

Oxford, our real estate investment and operating arm, is focused on climate-related risks and opportunities through our robust global energy and carbon management program. Through Oxford, we have committed to develop 1 million square feet of rooftop solar projects across North America. This is in addition to 120,000 square feet of rooftop projects already developed in Washington, Quebec City and Toronto.

Oxford aims to be a leader in developing and operating energy-efficient, low-carbon buildings. We measure greenhouse gas emissions, energy usage, and the number of “green building” certifications. We also measure waste diversion and water intensity, consistent with our commitment to managing resources responsibly.

Finally, we have established an ambitious target for reducing carbon emissions per square foot. While developing this target, we referred to various science-based methodologies, and employed both a “top-down” and “bottom-up” approach. We set a 30% carbon reduction target by 2025, relative to a 2015 base year-end and are on target, having achieved a 9% reduction over the first three years. We consider this target when we set our annual property budgets, and employ a rigorous reporting and monitoring system. This target also impacts employee compensation and recognition programs.

# ASSET CLASS INVESTMENT PERFORMANCE

## PUBLIC INVESTMENTS

Net Return

**16.4%**

**Benchmark:** 6.0%
**2018:** (4.6)%
**3-year average:** 7.4%

Net Investment Income

**$7.7** billion

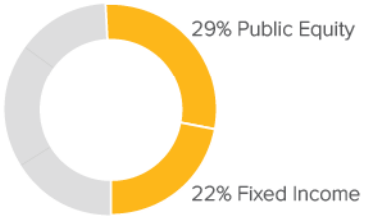
**2018:** $(2.3) billion

Net Assets

**$56.3** billion

**2018:** $48.5 billion

Asset Mix Exposure




### INVESTMENT APPROACH

Our approach to investing in public investments, which include fixed income and public equities, is to focus on high-quality investments that can generate sustainable income and growth, which we believe results in more consistent returns and lower volatility. We seek investments in companies with strong balance sheets and resilient business models. We partner with leading businesses, operators and best-in-class investors to access investment opportunities around the world. Our objective is to construct a well-diversified portfolio, across geographies, sectors, strategies and income streams, that will deliver long-term, consistent, absolute returns to fund the pension liabilities. Over the long term we expect to derive approximately two thirds of investment returns from cash interest and dividends and one-third of investment returns from capital gains.

### 2019 PERFORMANCE

Our public investments generated a net return of 16.4% in 2019, compared to a net loss of 4.6% for 2018 and our 2019 benchmark of 6.0%. This represents a net investment income of $7.7 billion in 2019, compared to a net investment loss of $2.3 billion in 2018.

Our returns reflect the trends in broad public market indices, which were very strong in 2019. This follows 2018 when virtually all indices had negative returns. OMERS public equities gained 20.3% in 2019, compared to a loss of 8.3% in 2018. Inflation-linked bonds and government bonds gained 7.1% and 1.2% respectively in 2019, mainly due to a compression in the level of yields. This compares to 2018 when Inflation-linked bonds and government bonds generated losses of 0.4% and 0.6%, respectively. Credit investment returns were 8.0% in 2019, compared to 3.1% in 2018, primarily due to lower interest rates and credit spreads.

### CAPITAL ALLOCATION

Public investments increased to $56.3 billion from $48.5 billion at the end of 2018. This increase was primarily from strong asset performance.

### SUSTAINABLE INVESTING IN PUBLIC INVESTMENTS

We actively engage with our most significant investee companies as a shareholder, expressing our views through meetings with management, sometimes with boards of directors, and regularly casting our votes on proxies in accordance with our established guidelines. We consider and regularly monitor Sustainable Investing metrics that are relevant and material to our key investments alongside other factors as part of our investment decisions and ongoing asset-management responsibility. We do this through proxy voting, where we exercise our ownership rights through the proxy process by voting our shares based on OMERS Proxy Voting Guidelines. These guidelines promote good corporate governance. We regularly review these guidelines and update them to reflect current issues. We retain flexibility to consider specific circumstances on any matter, so that we can exercise our votes in the best interests of OMERS.

Shareholder Engagement: We encourage responsible corporate behaviour and accountability by speaking directly to management teams and boards of directors, where appropriate.

## INFRASTRUCTURE

Net Return

**8.7%**

**Benchmark:** 7.9%
**2018:** 10.6%
**3-year average:** 10.5%

Net Investment Income

**$1.7** billion

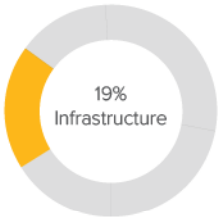
**2018:** $1.8 billion

Net Assets

**$21.3** billion

**2018:** $17.9 billion

Asset Mix Exposure




### INVESTMENT APPROACH

Our approach to investing in infrastructure is to seek reliable income and strong cash flows over the long term through investments in large-scale infrastructure services or businesses in energy, social infrastructure, transportation and telecommunications – primarily in North America, Europe and the Asia-Pacific region.

The infrastructure services or businesses we invest in generally have high barriers to entry and are often highly regulated and supported by long-term arrangements that provide an effective way to manage risk.

We take a patient and disciplined approach to infrastructure investing, and we execute on the prudent diversification of our portfolio. We actively manage the absolute and relative exposures, such as industrial sector, technology, demographics and currency, through dynamic asset and portfolio management.

### 2019 PERFORMANCE

The infrastructure asset class net return was 8.7%, compared to 10.6% for 2018 and our 2019 benchmark of 7.9%. This represents net investment income of $1.7 billion in 2019, compared to $1.8 billion in 2018 and an operating cash yield of 7.1% in 2019, compared to 5.9% in 2018.

In 2019 our performance was attributable to our active asset management focus which led to solid operational performance across a number of our assets. This was despite increased regulatory pressures, particularly in Europe.

### CAPITAL ALLOCATION

Infrastructure investments increased to $21.3 billion in 2019, up from $17.9 billion in 2018. This increase was primarily attributable to the progress made with our capital deployment strategy. During 2019, we invested in Puget Holdings LLC (a regulated utility in the U.S.), SFR FttH (a fibre-to-the-home business in France), VTG Aktiengesellschaft (a private railcar lessor based in Germany) and IndInfravit Trust (a trust holding a portfolio of toll roads in India).

## PRIVATE EQUITY

Net Return

**4.6%**

**Benchmark:** 11.0%
**2018:** 13.5%
**3-year average:** 9.7%

Net Investment Income

**$0.6** billion

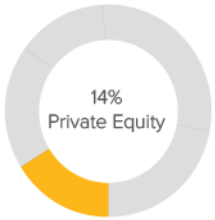
**2018:** $1.6 billion

Net Assets

**$15.7** billion

**2018:** $14.2 billion

Asset Mix Exposure




### INVESTMENT APPROACH

Our approach to investing in private equity is to acquire interests in private companies throughout various phases of the investment lifecycle including venture, growth and buyout capital, primarily headquartered in North America and Europe. Our objective is to generate strong capital returns, while appropriately managing risk. We take a thoughtful approach to capital deployment and invest in companies with solid business fundamentals, strong management teams, and with opportunities to grow both organically and through acquisitions.

### 2019 PERFORMANCE

The private equity asset class net return was 4.6%, compared to 13.5% in 2018 and our 2019 benchmark of 11.0%. This represents net income of $0.6 billion in 2019, compared to $1.6 billion in 2018. Several investments delivered strong returns through operational performance and acquisitions. The lower performance overall was due to the absence of any significant exits in 2019 and weaker operating performance in certain assets. We measure success over the longer term and our focus remains on positioning assets for sale to capitalize on our value creation.

### CAPITAL ALLOCATION

Total investments in private equity increased to $15.7 billion at the end of 2019 compared to $14.2 billion, as at December 31, 2018. This increase was primarily driven by acquisitions. In 2019, the significant transactions included the acquisition of Community Vet Partners (an operator of vet hospitals in the U.S.) and the disposition of a portion of Caliber Collision Centres (a vehicle collision repair company in the U.S.).

### SUSTAINABLE INVESTING IN INFRASTRUCTURE AND PRIVATE EQUITY

When considering a potential investment, we employ a framework to review relevant ESG factors. We tailor the depth of assessment required for potential investments, as required, to ensure consistency with OMERS sustainable investing beliefs.

OMERS actively enhances ESG practices across our portfolio through the role we take in the management of our portfolio companies. Including having regular direct contact with management teams, our governance rights are commensurate with our equity positions, including negative control rights, participation on boards and related committees. In addition, we often appoint independent directors to bring in specialized skills and varied experiences, where necessary.

## REAL ESTATE

Net Return

**8.3%**

**Benchmark:** 7.9%
**2018:** 8.7%
**3-year average:** 9.4%

Net Investment Income

**$1.4** billion

**2018:** $1.3 billion

Net Assets

**$17.5** billion

**2018:** $18.1 billion

Asset Mix Exposure

### INVESTMENT APPROACH

Our approach to investing in real estate is centered on building a world-class global real estate, investment, development and management platform that delivers sustainable income and capital returns. Oxford Properties Group (Oxford) executes its strategy as the owner, developer and manager of some of the world's best real estate assets.

Oxford is a disciplined and thematic global real estate investor in high-quality assets in real estate sectors and markets where it can outperform and deliver superior long-term returns. Oxford invests in a diversified portfolio of office, retail, industrial, multi-residential, hotel properties and alternative assets, in gateway and growth markets in Canada, the U.S., Europe and Asia-Pacific. Our portfolio consists of 100 million square feet of office, retail and industrial space, 9,100 multi-residential units and 3,000 hotel rooms. Oxford uses its expertise in leasing, management and development to add value to its investments.

### 2019 PERFORMANCE

The real estate asset class net return in 2019 was 8.3%, compared to 8.7% in 2018, and our 2019 benchmark of 7.9%. This represents net investment income of $1.4 billion in 2019, compared to $1.3 billion in 2018.

Performance in 2019 was driven by strong operating results and realized and unrealized mark-to-market gains on the asset portfolio, offset by mark-to-market losses on our long-term debt portfolio due to lower interest rates.

## CAPITAL ALLOCATION

Total investment in real estate decreased to $17.5 billion as at December 31, 2019, compared to $18.1 billion, as at December 31, 2018 as we continued to execute on our strategy to re-balance the portfolio, which included several acquisitions, the dispositions of non-core assets and committing to over 20 new developments.

In 2019, Oxford continued to focus on increasing its portfolio weighting to the multi-residential and industrial sectors with a number of key acquisitions. Also aligned with our strategy, we successfully completed a number of sales transactions including; non-core assets acquired in 2018 as part of the larger portfolio acquisitions of Investa Office Fund in Australia, and IDI Logistics in the U.S., as well as, the sale of our interest in several office properties in global cities. Oxford also entered into a definitive agreement to sell a 75% non-managing interest in its Western Canada resort hotel portfolio which is expected to close subsequent to year-end.

In 2019, Oxford continued to make significant progress on more than 30 active development projects. Notably, Oxford executed a lease agreement with a major tenant for the entire 1.3 million square foot New York office development (St. John's Terminal) significantly de-risking the development project, and broke ground at The Stack (Vancouver, Canada).

## SUSTAINABLE INVESTING IN REAL ESTATE

Oxford Properties takes a leadership approach to sustainability across its global 100 million square foot portfolio. Oxford develops strategies, sets targets and benchmarks performance using disciplined practices and new technologies to achieve outstanding results in a range of areas, including, energy efficiency; waste management; pollution; climate impact and anti-corruption.

Oxford develops and operates its buildings consistent with best-in-class sustainability standards across asset classes and markets, including LEED (Canada/U.S. office), BOMA BEST (Canada retail/industrial) and BREEAM (U.K. office). Oxford's list of industry firsts, external awards and achievements related to sustainability is extensive. Notably, in 2019 Oxford was again honoured as #1 by GRESB in the North America Diversified Office / Retail category and in the top 3% globally across over 900 funds and companies. Oxford also announced and commenced construction on Canada's first carbon neutral building with The Stack office building in Vancouver, Canada.

Oxford's sustainability program is driven by a set of Guiding Principles related to Leadership, Performance, Innovation, Credibility, Risks and Opportunities, and Transparency and Engagement. The program includes a range of commitments and activities around focused themes, including:

**CLIMATE AND ENERGY** We are a leader in the development and operation of energy-efficient, low-carbon buildings. Our priorities include carbon emissions, energy efficiency and renewable energy.

**MATERIALS AND RESOURCES** We critically evaluate the environmental and health aspects of the materials and resources we procure and use in our buildings. Our priorities include materials selection, waste diversion and water consumption.

**WELL-BEING** We incorporate world-class features and amenities in our buildings that support the success of our customers and help them live healthy and active lives. Our priorities include indoor air quality, common areas and customer amenities.

**COMMUNITY** We engage our stakeholders, creating outstanding buildings and exceptional places and giving back to our communities. Our priorities include partnerships, placemaking and volunteering.

# THE PLAN'S INVESTMENT RETURN HISTORY

While we measure our investment performance annually, OMERS emphasizes long-term performance, as pensions are paid over decades. Consistent long-term performance is important. The table below sets out the Plan's historical returns over a one-, three-, five-, 10- and 20-year period.

| Net return for the period ending December 31, 2019 | 1-Year | 3-Year | 5-Year | 10-Year | 20-Year |
|---|---|---|---|---|---|
| | 11.9% | 8.5% | 8.5% | 8.2% | 6.5% |

# INVESTMENTS OUTLOOK

In 2020, we expect the global economy will gradually pick up momentum through the year. This growth will be fueled by global monetary and fiscal stimulus that began in 2019. This is not without some headwinds, as we expect geopolitical instability, trade tensions and the global effects of COVID19 virus will continue to introduce uncertainty in the market. Over time, we expect the secular trends of aging populations and rising public indebtedness will increasingly weigh on economies.

We expect future long-term returns to be lower than those we have earned in the past. We have reflected this risk of decreasing investment return expectations in our risk assessments, our 2025 Strategy, and our protocol for setting the discount rate.

# RISK MANAGEMENT

**We define "risk" as an event, action or inaction that results in uncertainty around whether OMERS can effectively execute on its strategies and achieve its business objectives, or which could cause a significant opportunity to be missed.**

The AC Board has approved a risk framework, which describes overall risk management governance and details the structure for categorizing risks to which the organization is exposed. The Chief Risk Officer is responsible for our Risk Management Group, which provides independent and objective analysis and risk reporting to both the Senior Executive Team and OMERS Boards of Directors. This risk management approach provides a unified risk assessment across both the AC and SC, enabling unified risk management strategies across the two organizations.

OMERS governance therefore plays an instrumental role in supporting risk management. Inadequate governance could result from insufficient governance structures, processes and culture, and could cause lower-quality decision-making, with adverse effects on OMERS strategy, risk management and operations. We use a bespoke framework to assist the Governance Committees of the Boards and the Joint Council to evaluate our governance practices.

Day-to-day accountability for managing and ongoing execution remains with the business units and functions responsible for making operational decisions.

Within the context of the risk framework, we identify, assess, measure, mitigate, monitor and report risks to the Plan. We categorize these risks as follows: Pension, Investment, Operational, and Emerging risks. The risk inherent in the interaction of these categories together is funding risk, which we define as the risk that OMERS will need to increase contributions and/or reduce benefits. Our funding management strategy, discount rate methodology, and investment decisions in aggregate help manage funding risk.

The Boards of Directors also approve risk appetite statements, which quantitatively and qualitatively describe the desired level of risk within the organization. The Primary Plan risk appetite statement addresses funding risk, and additional "subsidiary" risk-appetite statements address Pension, Investment, and Operational risk.

The risk appetite statements:

- help define the desired level of risk within the Primary Plan and each of the respective risk categories;
- determine the nature, types, and degree of risk that OMERS is willing to assume through the articulation of qualitative statements and risk tolerances;
- establish metrics that allow OMERS to quantitatively assess its risk positioning relative to its desired risk appetite, as articulated by the qualitative statements and risk tolerances; and
- provide the Boards and their Committees with the necessary information and transparency required to effectively discharge their risk oversight responsibilities and make key strategic decisions.

**A brief overview of each subsidiary risk category, its major components, and how we manage the more granular risks is provided below. The decisions we make to manage these risks, ultimately address the ability of the Plans to sustain their long-term obligations to pay pensions.**

## 1 PENSION RISK

Pension Risk is the risk of significant changes in Plan liabilities and normal cost, or the risk of Plan design being inconsistent with design objectives. There are three key elements of Pension risk:

1. the risk of experiencing significant, unexpected changes in OMERS pension liabilities and normal cost due to demographic experience or assumption changes;
2. the risk of failing to deliver appropriate value or perceived value to members and employers; and
3. the risk of inequitable sharing of risks across generations of categories of members.

To evaluate and address these risks, we regularly review our assumption-setting philosophy and assumptions and methods in accordance with our Funding Policy; measure and assess value and equity of the Plan design and the actual experience of members; and assess the trade-off that must be made between inter-generational equity and contribution and benefit stability.

We continuously enhance tools, practices and resources to deliver insights and analysis which help inform strategic decisions.

## 2 INVESTMENT RISK

Investment Risk is the risk that investments will underperform our required return targets. There are key aspects of Investment Risk that affect the Plan: risk of permanent loss of capital, risk of an inappropriate risk-and-return trade-off, liquidity risk, and the risk that we are unable to execute our investment strategies. Items that are evaluated in assessing a permanent loss of capital include market risk, credit risk, counterparty risk, foreign exchange risk and valuation risk. Many of these categories are evaluated using quantitative measures. These risks are discussed in further detail in the Consolidated Financial Statements.

The risk-and-return trade-off is considered in the context of the ability of the strategic long-term asset mix to achieve the required returns to meet OMERS objectives. Liquidity considers both short-term and longer-term requirements and helps promote active planning. Lastly, we consider the ability to execute our investment strategies.

This mainly involves qualitative risk analysis. The evaluation of Investment Risk provides support for strategic investment decisions.

## 3 OPERATIONAL RISK

Operational Risk is the risk of loss or other adverse impacts arising from operational failures such as failure in people, processes, systems, and infrastructure. Examples of Operational Risk include the risk:

1. of failing to efficiently and effectively manage the day-to-day business operations for pension administration and member and employer interactions;
2. that we may not have the appropriate talent in place to manage and support business activities;
3. that our systems and IT infrastructure may not appropriately support business activites, including protecting our member and investment information against cyber incidents;
4. that we are not compliant with laws and regulations; and
5. of not having effective process controls in place, or the major initiatives are not managed effectively.

The Operational Risk management program has a range of tools and processes that guide how OMERS identifies, evaluates and tracks mitigation activities on an ongoing basis, including regular internal reporting on specific metrics for each area of risk.

## 4 EMERGING RISKS

Emerging Risks are defined as risks that are new, evolving or already known which lack specificity and/or are difficult to quantify, and individually or in combination, have the potential to gradually or suddenly impact OMERS ability to achieve its objectives.

We apply our framework, which defines six key Emerging Risk dimensions that support the identification and classification of emerging trends that are most relevant to OMERS and provide a more structured approach to categorizing trends. The six dimensions are Economic, Environmental, Geopolitical, Government/Regulatory, Societal and Technological. Emerging Risks may or may not fall within the other three categories of risk noted above.

As the pension landscape and investing environments shift, and as ESG considerations evolve, OMERS will continue to identify, measure and manage those emerging and existing risks that impact the Plan's long-term financial health.

# RECONCILIATION OF NON-GAAP MEASURES

## RECONCILIATION OF NET INVESTMENT ASSETS

The classification and measurement of certain investment assets and investment liabilities in this MD&A differ from the amounts reported in our Consolidated Financial Statements in accordance with GAAP. The following table sets out the reconciliation of Net Investment Assets and Net Investment Liabilities in Note 3 in the Consolidated Financial Statements, to the Net Investment Asset exposure in this MD&A.

| | | Reclassifications | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Consolidated Financial Statements** | | Derivative Exposures[1] | Private Credit Funds[2] | Preferred Shares[3] | Corporate Bonds[4] | Public equity Funds[5] | Recourse debt[6] | OMERS Return Agreement[7] | Other | **MD&A** |
| $millions as at December 31, 2019 | | | | | | | | | | |
| **Fixed Income** | | | | | | | | | | **Fixed Income** |
| Inflation-Linked Bonds | **2,707** | | | | | | | | 36 | **2,743** Inflation-Linked Bonds |
| Nominal bonds and Debentures | **4,336** | 1,030 | | | (1,916) | | | | 18 | **3,468** Government Bonds |
| Private debt and mortgages | **8,446** | 149 | 5,959 | 1,931 | 1,916 | | (430) | | 339 | **18,310** Credit |
| **Equities** | | | | | | | | | | **Equities** |
| Public Equity | **21,080** | 11,866 | | (1,931) | | 703 | | | 274 | **31,992** Public Equity |
| Private Equity | **22,561** | | (5,959) | | | (703) | (3) | | (194) | **15,702** Private Equity |
| **Real Assets** | | | | | | | | | | **Real Assets** |
| Infrastructure | **25,292** | | | | | | (2,643) | (1,174) | (127) | **21,348** Infrastructure |
| Real Estate | **20,497** | | | | | | (2,675) | (644) | 315 | **17,493** Real Estate |
| **Short-Term Instruments** | | | | | | | | | | **Short-Term Instruments** |
| Cash and Short-Term deposits | **14,188** | | | | | | (1,283) | (100) | (392) | **12,413** Cash |
| | | (13,045) | | | | | | | 384 | **(12,661)** Economic Leverage |
| **Investment Related Assets & Liabilities** | **(6,867)** | | | | | | 7,034 | | (167) | — |
| **Total Net Investment Assets** | **112,240** | — | — | — | — | — | — | (1,918) | 486 | **110,808** **Total Net Investment Assets** |

[1] Derivatives are measured at their fair value in the Consolidated Financial Statements. In this MD&A, to arrive at the Plan's ultimate exposure by asset class, derivatives are measured at their exposure value. The effect of derivatives exposure is reflected in each asset class, with an offset to economic leverage. Economic leverage is the difference between the exposure to an asset class and the fair value of the derivatives in the asset class.

[2] Private credit funds are classified as private equity in the Consolidated Financial Statements, and are classified as credit in this MD&A.

[3] Preferred shares are classified as public equity in the Consolidated Financial Statements, and are classified as credit in this MD&A.

[4] Corporate bonds are classified as nominal bonds and debentures in the Consolidated Financial Statements, and are classified as credit in this MD&A.

[5] Private funds that are invested in public equities are classified as private equity in the Consolidated Financial Statements, and are classified as public equity in this MD&A.

[6] Recourse debt is classified as investment liabilities in the Consolidated Financial Statements, and is classified in the respective asset classes which the debt is financing in this MD&A.

[7] OMERS has entered into agreements that provide eligible clients with access to the performance of its real estate and infrastructure businesses. The real estate and infrastructure assets are gross of the related liabilities on the Consolidated Financial Statements, and net of the related liabilities in this MD&A.

# RECONCILIATION OF NET INVESTMENT INCOME

The following table sets out the reconciliation of Net Investment Income for each asset class as reported in Note 8 in the Consolidated Financial Statements, to the Net Investment Income in this MD&A.

| | | Reclassifications | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Consolidated Financial Statements** | | Derivative Exposures[1] | Private Credit Funds[2] | Preferred Shares[3] | Corporate Bonds[4] | Public equity funds[5] | Recourse debt[6] | Contractual Agreements[7] | Other Items | **MD&A** |
| In $ millions as at December 31, 2019 | | | | | | | | | | |
| **Fixed Income** | | | | | | | | | | **Fixed Income** |
| Inflation-Linked Bonds | **228** | | | | | | | (3) | 2 | **227** Inflation-Linked Bonds |
| Nominal bonds and Debentures | **1,291** | (1,118) | | | (117) | | | (1) | 5 | **60** Government Bonds |
| Private debt and mortgages | **316** | 795 | (32) | 140 | 117 | | 14 | (19) | | **1,331** Credit |
| **Equities** | | | | | | | | | | **Equities** |
| Public Equity | **5,791** | 237 | | (140) | | 39 | | (84) | (6) | **5,837** Public Equity |
| Private Equity | **639** | 55 | 32 | | | (39) | 7 | (9) | (48) | **637** Private Equity |
| **Real Assets** | | | | | | | | | | **Real Assets** |
| Infrastructure | **1,859** | | | | | | 50 | (135) | (66) | **1,708** Infrastructure |
| Real Estate | **1,459** | | | | | | 56 | (72) | (4) | **1,439** Real Estate |
| Cash and Short-Term deposits | **198** | 31 | | | | | (127) | (3) | 100 | **199** Cash and Short-Term Instruments |
| **Total Investment Income** | **11,781** | — | — | — | — | — | — | (326) | (17) | **11,438** **Total Primary Plan** |
| Income credited under contractual agreements | **(326)** | | | | | | | 326 | 17 | **17** **RCA Investment Fund** |
| Net Investment Income/ (Loss) | **11,455** | — | — | — | — | — | — | — | — | **11,455** |

[1] Income from derivatives for fixed income assets is classified as nominal bonds and debentures in the Consolidated Financial Statements, and is classified based on the asset exposure in this MD&A.

[2] Losses from private credit funds are classified as private equity in the Consolidated Financial Statements, and are classified as credit in this MD&A.

[3] Income from preferred shares is classified as public equity in the Consolidated Financial Statements, and is classified as credit in this MD&A.

[4] Income from corporate bonds is classified as nominal bonds and debentures in the Consolidated Financial Statements, and is classified as credit in this MD&A.

[5] Income from private funds that are invested in public equities is classified as private equity in the Consolidated Financial Statements, and is classified as public equity in this MD&A.

[6] Interest income related to recourse debt is classified as short-term deposits in the Consolidated Financial Statements, and is classified in the respective asset classes which the debt is financing in this MD&A.

[7] OMERS has entered into contractual agreements to invest funds on behalf of the Board of Trustees of Ryerson University and the Transit of Windsor Fund. OMERS has also entered into agreements that provide eligible clients with access to the performance of its real estate and infrastructure businesses. The investment income related to these contracts are reported gross in Total Investment Income in the Consolidated Financial Statements, and net in this MD&A.

04

# FINANCIAL STATEMENTS: OMERS ADMINISTRATION CORPORATION

# RESPONSIBILITIES OF MANAGEMENT, ACTUARY AND INDEPENDENT AUDITORS

The consolidated financial statements of AC have been prepared by AC Management (Management) and approved by the Board of AC (AC Board). Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with Canadian accounting standards for pension plans. Management is responsible for designing, implementing and maintaining an adequate system of internal control over financial reporting to enable the preparation and fair presentation of the consolidated financial statements, including amounts based on estimates and judgment. In this regard, we are responsible for establishing policies and procedures that pertain to the maintenance of accounting systems and records, the authorization of receipts and disbursements, the safeguarding of assets and for reporting financial information. In addition, our internal audit team reviews AC's systems of internal controls over financial reporting and disclosure to determine whether these controls are appropriate and operating effectively.

The AC Board is responsible for approving the annual consolidated financial statements. The Audit & Actuarial Committee, which is comprised of directors who are not officers or employees of AC, assists the AC Board in executing this responsibility. The Audit & Actuarial Committee meets regularly with Management, the internal audit team and independent external auditors to review the scope and timing of their respective audits as well as to review any internal control or financial reporting issues and their resolution. The Audit & Actuarial Committee reviews the annual consolidated financial statements and recommends them to the AC Board for approval.

The external actuary is appointed by the AC Board. It is the external actuary's responsibility to carry out annual valuations of the accrued pension obligations of the OMERS Pension Plans in accordance with accepted actuarial practice and to report thereon to the AC Board. The results of the external actuary's valuation are set out in the Actuarial Opinion. In performing the valuation, the external actuary values the benefits provided under the OMERS Pension Plans using appropriate assumptions about future economic conditions (such as inflation, salary increases and investment returns) and demographic factors (such as mortality, termination rates and retirement ages). These assumptions take into account the circumstances of AC and its active, deferred and retired members.

The independent external auditors are also appointed by the AC Board. Their responsibility is to report to the AC Board whether in their opinion the consolidated statements of financial position as at December 31, 2019 and 2018 and the consolidated statements of changes in net assets available for benefits and the statements of changes in pension obligations for the years ended December 31, 2019 and 2018 present fairly in all material respects the financial position, the changes in net assets available for benefits and changes in pension obligations in accordance with Canadian accounting standards for pension plans. The independent external auditors have full and unrestricted access to Management and the Audit & Actuarial Committee to discuss any findings arising from their audit related to the integrity of financial reporting and the adequacy of internal control systems on which they rely for the purposes of their audit. The auditors' report outlines the scope of their examination and opinion.

Based on my knowledge, the Annual Report does not contain any untrue statement of a material fact, or omit to state a material fact, that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by this Annual Report.

Based on my knowledge, the annual financial statements, together with the other financial information included in this Annual Report, fairly present in all material respects the financial position, changes in net assets available for benefits and changes in pension obligations of AC as of the date and for the periods presented in this Annual Report.

**Michael Latimer**
Chief Executive Officer

**Jonathan Simmons, FCPA, FCA**
Chief Financial Officer

Toronto, Ontario
February 21, 2020

# ACTUARIAL OPINION

We conducted actuarial valuations as at December 31, 2019 of the OMERS Primary Pension Plan (the Primary Plan) and the Retirement Compensation Arrangement for the OMERS Primary Pension Plan (the RCA) administered by OMERS Administration Corporation (AC). The purpose of the valuations is to fairly present the actuarial funded status of the Primary Plan and the RCA as at December 31, 2019, for inclusion in this Annual Report in accordance with Section 4600 of Part IV of the Chartered Professional Accountants of Canada (CPA Canada) Handbook.

The results of the actuarial valuation of the Primary Plan disclosed total going concern actuarial liabilities of $107,687 million in respect of benefits accrued for service to December 31, 2019 (comprising $106,443 million with respect to the defined benefit component and $1,244 million with respect to the AVC component). The actuarial assets at that date were $104,290 million (comprising $103,046 million with respect to the defined benefit component and $1,244 million with respect to the AVC component), indicating a going concern actuarial deficit of $3,397 million.

The actuarial liability in respect of RCA benefits accrued for service to December 31, 2019, net of the RCA assets, was $766 million. The RCA is not fully pre-funded. The funding of the RCA is managed on a modified pay-as-you go basis and monitored to ensure that the fund will have sufficient assets to provide for the projected benefit payments over the 20-year period following each valuation date.
The actuarial valuations of the Primary Plan and the RCA as at December 31, 2019 were conducted using the Projected Benefit Method Prorated on Services, and membership data as at October 31, 2019 and financial information as at December 31, 2019 supplied by the AC.

We reviewed the data for reasonableness and consistency with the data provided in prior years. In our opinion,

- the membership data are sufficient and reliable for the purpose of the valuations;
- the assumptions adopted were set with reference to the Primary Plan's and RCA's funding policies and are appropriate for the purpose of the valuations;
- the methods employed in the valuations are appropriate for the purpose of the valuations; and
- the valuations have been completed in accordance with our understanding of the requirements of the CPA Canada Handbook Section 4600.

The future experience of the Primary Plan and the RCA may differ from the actuarial assumptions, resulting in gains or losses which will be revealed in future valuations.

The valuations were prepared and our opinions are given in accordance with accepted actuarial practice in Canada.

Respectfully submitted,
Towers Watson Canada Inc.

**Philip A. Morse**
Fellow, Canadian Institute of Actuaries

**Geoffrey Melbourne**
Fellow, Canadian Institute of Actuaries

Toronto, Ontario
February 21, 2020

# INDEPENDENT AUDITOR'S REPORT

To the Board of OMERS Administration Corporation

**Our opinion**

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of OMERS Administration Corporation and its subsidiaries (together, AC) as at December 31, 2019 and 2018, and the changes in its net assets available for benefits and changes in its pension obligations for the years then ended in accordance with Canadian accounting standards for pension plans.

*What we have audited*

AC's consolidated financial statements comprise:

- the consolidated statements of financial position as at December 31, 2019 and 2018;
- the consolidated statements of changes in net assets available for benefits for the years then ended;
- the consolidated statements of changes in pension obligations for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

**Basis for opinion**

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

*Independence*

We are independent of AC in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

**Other information**

Management is responsible for the other information. The other information comprises the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report. Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

**Responsibilities of management and those charged with governance for the consolidated financial statements**

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with Canadian accounting standards for pension plans, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing AC's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate AC or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing AC's financial reporting process.

**Auditor's responsibilities for the audit of the consolidated financial statements**

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of AC's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on AC's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause AC to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within AC to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

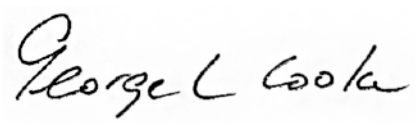
**Chartered Professional Accountants, Licensed Public Accountants**

Toronto, Ontario
February 21, 2020

# CONSOLIDATED STATEMENT OF FINANCIAL POSITION

| As at December 31, (in millions of Canadian dollars) | | 2019 | | 2018 |
|---|---|---|---|---|
| **Net Assets Available for Benefits** | | | | |
| Assets | | | | |
| Investments (note 3) | **$** | **119,107** | $ | 108,424 |
| Investment related assets (note 3) | | **2,411** | | 2,780 |
| Contributions receivable | | | | |
| Employers | | **166** | | 164 |
| Members | | **166** | | 164 |
| Other assets | | **658** | | 330 |
| Total Assets | | **122,508** | | 111,862 |
| Liabilities | | | | |
| Investment related liabilities (notes 3 and 4) | | **9,278** | | 10,923 |
| Amounts payable under contractual agreements (note 5) | | **3,485** | | 3,247 |
| Other liabilities | | **365** | | 253 |
| Total Liabilities | | **13,128** | | 14,423 |
| **Net Assets Available for Benefits** | **$** | **109,380** | $ | 97,439 |
| **Accrued Pension Obligation and Surplus/(Deficit)** | | | | |
| Primary Plan (note 6) | | | | |
| Defined benefit component | | | | |
| Accrued pension obligation | **$** | **106,443** | $ | 99,058 |
| Surplus/(Deficit) | | | | |
| Funding surplus/(deficit) | | **(3,397)** | | (4,191) |
| Actuarial value adjustment to net assets available for benefits | | **4,928** | | 1,401 |
| | | **1,531** | | (2,790) |
| Additional Voluntary Contributions component pension obligation | | **1,244** | | 1,023 |
| Accrued Pension Obligation and Surplus/(Deficit) - Primary Plan | | **109,218** | | 97,291 |
| Retirement Compensation Arrangement (note 7) | | | | |
| Accrued pension obligation | | **928** | | 851 |
| Surplus/(Deficit) | | **(766)** | | (703) |
| Accrued Pension Obligation and Surplus/(Deficit) - Retirement Compensation Arrangement | | **162** | | 148 |
| **Accrued Pension Obligation and Surplus/(Deficit)** | **$** | **109,380** | $ | 97,439 |

The accompanying notes are an integral part of these consolidated financial statements.
These financial statements were approved by the Board of Directors on February 21, 2020.
Signed on behalf of the Board of OMERS Administration Corporation



**George Cooke**
AC Board Chair

**Laurie L. Hutchinson**
Chair, Audit & Actuarial Committee

# CONSOLIDATED STATEMENT OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

| For the year ended December 31, (in millions of Canadian dollars) | | 2019 | | 2018 |
|---|---|---|---|---|
| **Changes Due to Investment Activities** | | | | |
| Net investment income (note 8) | **$** | **11,455** | $ | 2,205 |
| **Total Changes Due to Investment Activities** | | **11,455** | | 2,205 |
| **Changes Due to Pension Activities** | | | | |
| Total contributions received (note 10) | | **4,349** | | 4,370 |
| Assumption of City of Toronto Pension Plans | | **973** | | 36 |
| Total benefits paid (note 11) | | **(4,646)** | | (4,277) |
| Pension administrative expenses (note 12) | | **(190)** | | (93) |
| **Total Changes Due to Pension Activities** | | **486** | | 36 |
| **Total Increase** | | **11,941** | | 2,241 |
| **Net Assets Available for Benefits, Beginning of Year** | | **97,439** | | 95,198 |
| **Net Assets Available for Benefits, End of Year** | **$** | **109,380** | $ | 97,439 |

The accompanying notes are an integral part of these consolidated financial statements.

# CONSOLIDATED STATEMENT OF CHANGES IN PENSION OBLIGATIONS

| For the year ended December 31, (in millions of Canadian dollars) | | 2019 | | 2018 |
|---|---|---|---|---|
| **OMERS Primary Pension Plan (note 6)** | | | | |
| **Defined Benefit Component** | | | | |
| Accrued pension obligation, beginning of year | **$** | **99,058** | $ | 93,614 |
| Interest accrued on benefits | | **5,917** | | 5,592 |
| Benefits accrued | | **3,491** | | 3,380 |
| Benefits paid | | **(4,589)** | | (4,225) |
| Assumption of City of Toronto Pension Plans | | **847** | | 30 |
| Experience (gains)/losses | | **195** | | 272 |
| Changes in actuarial assumptions and methods | | **—** | | 395 |
| Reduction in the discount rate | | **1,524** | | — |
| **Accrued Pension Obligation, End of Year** | | **106,443** | | 99,058 |
| **Additional Voluntary Contributions Component** | | | | |
| Additional Voluntary Contributions obligation, beginning of year | | **1,023** | | 817 |
| Contributions | | **127** | | 207 |
| Withdrawals | | **(34)** | | (22) |
| Attributed net investment income | | **128** | | 21 |
| **Additional Voluntary Contributions Obligation, End of Year** | | **1,244** | | 1,023 |
| **Retirement Compensation Arrangement (note 7)** | | | | |
| Accrued pension obligation, beginning of year | **$** | **851** | $ | 813 |
| Interest accrued on benefits | | **27** | | 26 |
| Benefits accrued | | **26** | | 27 |
| Benefits paid | | **(23)** | | (30) |
| Experience (gains)/losses | | **47** | | 34 |
| Changes in actuarial assumptions and methods | | **—** | | (19) |
| **Accrued Pension Obligation, End of Year** | **$** | **928** | $ | 851 |

The accompanying notes are an integral part of these consolidated financial statements.

(Amounts in millions of Canadian dollars except where otherwise noted)

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## NOTE 1

### Description of Plans Administered By OMERS Administration Corporation

OMERS Administration Corporation (AC) is a corporation without share capital, continued under the Ontario Municipal Employees Retirement System Act, 2006 (OMERS Act). AC is the administrator of the OMERS pension plans (OMERS Pension Plans) as defined in the OMERS Act and is trustee of the pension funds. The OMERS Pension Plans include the OMERS Primary Pension Plan (Primary Plan), the Retirement Compensation Arrangement for the OMERS Primary Pension Plan (RCA) and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (Supplemental Plan). As trustee of the Primary Plan's fund, AC holds legal title to the pension fund assets and the trust beneficiaries are primarily Primary Plan members. AC is responsible for administering the OMERS Pension Plans in accordance, as applicable, with the Pension Benefits Act (Ontario) (PBA), the Income Tax Act (Canada) (ITA), and the OMERS Act. Under the OMERS Act, the OMERS Sponsors Corporation (SC) is the sponsor of the OMERS Pension Plans.

The accrued pension obligations of any one of the OMERS Pension Plans cannot be funded by the assets of the other OMERS Pension Plans.

Effective June 8, 2019, Financial Services Regulatory Authority of Ontario (FSRA) assumed the regulatory responsibilities of the Financial Services Commission of Ontario (FSCO). The responsibility for administration of the Pension Benefits Act (Ontario) was transferred to FSRA at the above date.

**OMERS Primary Pension Plan**

The Primary Plan is a multi-employer, jointly sponsored pension plan, created in 1962 by an Act of the Ontario Legislature, whose members are mainly employees of Ontario municipalities, local boards, public utilities and non-teaching school board staff. The Primary Plan is governed by the OMERS Act, the PBA, the ITA and other applicable legislation. The benefit provisions and other terms of the Primary Plan are set out in the Primary Plan text. The Primary Plan consists of both the defined benefit component and the Additional Voluntary Contribution (AVC) component.

The Primary Plan is registered with the FSRA and the Canada Revenue Agency (CRA) under Registration #0345983.
Attributes of the defined benefit component of the Primary Plan include:

- Funding –The defined benefit component of the Primary Plan is funded by equal contributions from participating employers and members, and by the investment earnings of the Primary Plan assets. AC determines the regulatory minimum funding requirements in accordance with the ITA and PBA. The SC sets the actual contribution rates.
- Pensions – The normal retirement age (NRA) is 65 years for all Primary Plan members, except police officers and firefighters, who generally have a normal retirement age of 60 years. The Primary Plan is designed to provide lifetime defined benefit pensions. These pensions are calculated as a percentage of the member's earnings averaged over the highest 60 consecutive months, multiplied by years of credited service.

- Death Benefits – Death benefits are payable to a surviving spouse, eligible dependent children, designated beneficiary, or the member's estate upon the death of a member. Depending upon eligibility requirements, the benefits may be paid in the form of a survivor pension, lump sum payment or both.
- Escalation of Pensions – Pensions are increased for inflation through an annual adjustment equal to 100 per cent of the increase in the average Consumer Price Index (CPI) over the prior year's average. This adjustment is subject to a limit of six per cent in any one year. If the increase in the average CPI exceeds the six per cent limit, the excess is carried forward to future years.
- Disability Pensions – A disability pension is available at any age to an active member who becomes totally disabled as defined by the Primary Plan. The pension is calculated using a member's years of credited service and the average annual earnings during the member's highest 60 consecutive months of earnings consistent with a normal retirement pension. Generally, disability pensions continue until normal retirement.
- Income Taxes – The Primary Plan is a Registered Pension Plan as defined in the ITA and is not subject to income taxes for contributions or investment income received. The operations of certain entities holding private equity, infrastructure or real estate investments may be taxable.

The AVC component of the Primary Plan enables members to make additional voluntary contributions on which the member receives the net investment return of the Primary Plan. For the AVC component of the Primary Plan, the liability of the Primary Plan is members' AVC contributions plus/minus the net investment rate of return of the defined benefit component of the Primary Plan.

**Retirement Compensation Arrangement for the OMERS Primary Pension Plan**

The RCA is an arrangement that provides pension benefits for Primary Plan members with earnings exceeding the amount that generates the maximum pension allowed by the ITA with respect to service after 1991. It is a separate trust arrangement and is not governed by the PBA and is not a Registered Pension Plan under the ITA. The RCA is governed by the OMERS Act, the ITA and other applicable legislation and is funded by equal contributions from participating employers and members and by the investment earnings of the RCA fund. Current and future contributions are determined annually to ensure that the existing RCA fund and future investment earnings are expected to be sufficient to pay projected benefits and expenses over the 20-year period following each actuarial valuation date. The RCA net assets available for benefits are invested and accounted for separately from the Primary Plan and the Supplemental Plan, and the accrued pension obligation of the RCA is valued separately from the Primary Plan and Supplemental Plan accrued pension obligations. Expenses of the RCA are paid from the cash flows of the RCA fund.

**OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics**

The Supplemental Plan became effective on July 1, 2008, pursuant to the requirements of the OMERS Act. The benefit provisions and other terms of the Supplemental Plan are set out in the Supplemental Plan text. The Supplemental Plan is registered with FSRA and with CRA under Registration #1175892.
Until March 31, 2024, unless the Supplemental Plan has sufficient funds based on the portion of contributions allocated for administrative expenses, any administrative costs of the Supplemental Plan are funded through a startup grant from the Province of Ontario.

Participation in the Supplemental Plan is effective only upon agreement between employee groups and their employer. As at December 31, 2019 and December 31, 2018, no such agreement existed and hence the Supplemental Plan had no assets and no members.

# NOTE 2

## Summary of Significant Accounting Policies

### Basis of Presentation

AC follows the requirements of the Chartered Professional Accountants of Canada (CPA Canada) Handbook Section 4600 – Pension Plans, which is the basis for Canadian accounting standards for pension plans. The recognition and measurement of AC assets and liabilities are consistent with the requirements of CPA Canada Handbook Section 4600. For accounting policies that do not relate to its investment portfolio or pension obligations, AC follows the requirements of International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The financial statements also provide disclosures required by regulation 909 of the PBA.

These financial statements include the financial position, changes in net assets available for benefits and changes in pension obligations of AC and the OMERS Pension Plans.

Certain comparative figures have been restated to conform to the current year's presentation.

### Use of Estimates and Judgments

The preparation of consolidated financial statements requires AC Management (Management) to make estimates, judgments and assumptions that affect the reported values of assets and liabilities, income and expenses, accrued pension obligations and related disclosures. Actual results could differ from these estimates. Areas of significant accounting estimates and judgments include the determination of fair value of financial instruments including valuation of real estate, infrastructure, private equity and private debt investments, derivatives and the determination of the accrued pension obligation.

### Investments

All investment transactions are recorded at the point when the risks and rewards of ownership are transferred. Purchases and sales of publicly traded investments are recorded as of the trade date.

Investments are stated at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It is best evidenced by a quoted closing market price in an active market, if one exists. The determination of fair value is based on market conditions at a specific point in time and may not be reflective of future fair values. Detailed discussion on valuation methodology is presented in Note 3 – Investments.

The difference between the value of a fixed income investment at the time it was acquired and its current fair value takes into account changes in market rates and credit risk of the issuer that have occurred since the original acquisition. Unrealized appreciation/depreciation in the fair value of investments is the change in fair value adjusted for cash flows recognized during the year and is reflected in Changes due to Investment Activities in the Consolidated Statement of Changes in Net Assets Available for Benefits.

### Derivative Financial Instruments

Derivative financial instruments are financial contracts, the value of which are derived from changes in prices of underlying assets or indices. Derivative transactions are conducted in over-the-counter markets directly between two counterparties or cleared through clearinghouses, or on regulated exchange markets.

Derivative financial instruments are used, when appropriate, to manage the OMERS Pension Plans' asset mix and to assist in managing the exposure to market risk, by increasing or decreasing foreign currency, interest rate and price risk, without directly purchasing or selling the underlying assets or currencies. The fair value of the derivative contracts represents unrealized gains or losses from derivative contracts which are recorded in the Consolidated Statement of Financial Position. Fair value represents the cost of replacing all outstanding contracts under current market conditions. Contracts with a positive fair value are recorded as derivative asset in the investment related assets and contracts with a negative fair value are recorded as derivative liability in the investment related liabilities.

**Net Investment Income/(Loss)**

Investment income/(loss) includes accrued interest, dividends and real estate rental income. Gains and losses that have been realized on the disposal of investments and the unrealized appreciation/ depreciation required to adjust investments to their fair value are added to investment income to arrive at Total Investment Income in Note 8 – Net Investment Income/(Loss).

Investment income is recognized as interest and real estate rental income is earned, as dividends or distributions are declared, as investments are disposed of and as investments are adjusted to their fair value.

**Transaction and Pursuit Costs**

Transaction and pursuit costs which include broker commissions, legal and other professional fees incurred as a part of the due diligence of a potential or completed transaction are expensed to total investment income as incurred.

**External Manager Fees**

Base external manager fees for portfolio management are included in investment management expenses as incurred. Performance fees, which are contractually due to external managers for superior investment returns, and fees for pooled funds, where AC's investment return from the fund is net of fees, are expensed in investment income as incurred.

**Investment Liabilities**

Investment liabilities include commercial paper, term notes, debentures, and other debt obligations recourse to AC and incurred to acquire an investment. Investment liabilities also include the amounts payable in respect of securities sold under agreements to repurchase ("Repo Agreements"). Investment liabilities are financial instruments and are stated at fair value. The fair value of investment liabilities is estimated using discounted cash flows based on current market yields, except for items that are short-term in nature, for which cost plus accrued interest approximates fair value. The credit risk of AC is also considered in estimating the fair value of investment liabilities.

Liabilities incurred in entities in which AC has invested are netted as part of investment assets, even when the investment is in an entity over which AC has effective control or can exercise significant influence except for when there is recourse.

**Pending Trades**

Pending trades include accrued receivables/payables from unsettled transactions.

For securities transactions, the fair value of amounts due from pending trades and amounts payable from pending trades approximate their carrying amounts due to their short-term nature.

**Foreign Currency Translation**

Certain investments are denominated in foreign currencies. The fair values of such investments are translated into Canadian dollars at the year-end rate of exchange. Unrealized foreign exchange gains and losses arising from this translation are included in Net Gain/(Loss) on Investment Assets, Liabilities, and Derivatives in Note 8 – Net Investment Income/(Loss). Once a foreign currency denominated investment is sold, the realized foreign exchange gain or loss based on the rate at the settlement date is also recognized in Net Gain/(Loss) on Investment Assets, Liabilities, and Derivatives in Note 8 – Net Investment Income/(Loss).

**Accrued Pension Obligation**

The value of the accrued pension obligation of the Primary Plan's defined benefit component is based on the Projected Benefit Method Prorated on Services actuarial valuation prepared by an independent firm of actuaries. This accrued pension obligation is measured in accordance with accepted actuarial practice in Canada using actuarial assumptions and methods adopted by AC for the purpose of establishing the long-term funding requirements of the Primary Plan. The actuarial valuation included in the Consolidated Financial Statements is consistent with the valuation used for funding purposes.

The AVC pension obligation represents the Primary Plan's liability in respect of the AVC component of the Primary Plan and includes members' AVC contributions plus/minus the net investment rate of return of the defined benefit component of the Primary Plan.

The valuation methodology used in the estimation of the accrued pension obligation of the RCA is developed on a basis consistent with the accrued pension obligation of the Primary Plan's defined benefit component while recognizing the difference in the tax treatment. The accrued pension obligation of the RCA and the AVC pension obligation are separate from the accrued pension obligation of the Primary Plan's defined benefit component.

**Actuarial Value of Net Assets and Actuarial Value Adjustment**

The actuarial value of net assets for the Primary Plan is used in assessing the funded position of the Primary Plan, including the determination of minimum legally required contributions. The actuarial value adjustment to the fair value of net assets is the amount of net investment returns above or below the discount rate that are being smoothed and recognized over a five-year period. The fair value of net assets is adjusted by the actuarial value adjustment to arrive at the actuarial value of net assets.

**Surplus/Deficit**

For financial statement reporting, the surplus/deficit of the Primary Plan is based on the difference between the fair value of the Primary Plan's net assets available for benefits and the Primary Plan's accrued pension obligation. For funding purposes, the Primary Plan's surplus/deficit is based on the difference between the Primary Plan's actuarial value of net assets and the Primary Plan's accrued pension obligation. For the RCA, the surplus/deficit for financial statement reporting purposes is based on the difference between the fair value of RCA net assets available for benefits and the RCA's accrued pension obligation.

**Contributions**

Contributions from employers and members due to the OMERS Pension Plans as at the end of the year are recorded on an accrual basis. Service purchases that include, but are not limited to, leaves of absence, conversion of normal retirement age and transfers from other pension plans are recorded and service is credited when the purchase amount is received. Contributions for AVCs are recorded when the contribution is received.

**Benefits**

Benefit payments to retired members are recorded as they become due, at the first day of each month. Commuted value payments and transfers to other pension plans are recorded in the period in which PAC is notified. Accrued benefits for active members are recorded as part of the accrued pension obligation.

**Administrative Expenses**

Administrative expenses are incurred for direct pension administration, direct investment management and corporate services and are recorded on an accrual basis. Direct pension administration expenses represent expenses to provide direct services to OMERS Pension Plans members and employers. Direct investment management expenses represent expenses of managing OMERS Pension Plans investments. Corporate services expenses primarily include corporate information systems, accounting, legal and other governance expenses incurred to support either the pension administration or the investment management functions. These are allocated between pensions and investments based on an estimate of the use of resources.

# NOTE 3

## A. Investments

### Investments by Fair Value and Cost

Investments and investment related assets and liabilities are as follows:

| As at December 31, | 2019 | | 2018 | |
|---|---|---|---|---|
| | **Fair Value** | **Cost** | Fair Value | Cost |
| Fixed Income | | | | |
| Inflation-Linked Bonds | **$ 2,707** | **$ 2,602** | $ 3,884 | $ 3,608 |
| Canadian nominal bonds and debentures | **1,783** | **1,785** | 1,153 | 1,171 |
| Non-Canadian nominal bonds and debentures | **2,553** | **2,570** | 3,658 | 3,617 |
| Private debt and mortgages | **8,446** | **8,385** | 7,588 | 7,425 |
| | **15,489** | **15,342** | 16,283 | 15,821 |
| Equities | | | | |
| Public Equity | | | | |
| Canadian public equities | **6,902** | **6,688** | 6,668 | 7,020 |
| Non-Canadian public equities [(i)] | **14,178** | **12,410** | 11,972 | 11,235 |
| | **21,080** | **19,098** | 18,640 | 18,255 |
| Private Equity [(ii) (iv)] | | | | |
| Canadian private equities [(iii)] | **2,688** | **3,558** | 1,742 | 2,589 |
| Non-Canadian private equities [(i)] | **19,873** | **16,979** | 18,504 | 13,630 |
| | **22,561** | **20,537** | 20,246 | 16,219 |
| | **43,641** | **39,635** | 38,886 | 34,474 |
| Real Assets | | | | |
| Infrastructure Investments | **25,292** | **24,205** | 20,796 | 18,981 |
| Real Estate Investments | **20,497** | **15,974** | 22,110 | 17,866 |
| | **45,789** | **40,179** | 42,906 | 36,847 |
| Short-Term Instruments | | | | |
| Cash and short-term deposits [(v)] | **14,188** | **14,194** | 10,349 | 10,348 |
| Total Investments | **119,107** | **109,350** | 108,424 | 97,490 |
| Investment Related Assets | | | | |
| Investment receivables | **322** | **322** | 325 | 325 |
| Deferred assets, prepaid and other | **49** | **81** | 49 | 81 |
| Derivatives | **1,898** | **162** | 2,212 | 64 |
| Pending trades | **142** | **142** | 194 | 194 |
| | **2,411** | **707** | 2,780 | 664 |
| Investment Related Liabilities | | | | |
| Investment liabilities (note 4) | **(8,082)** | **(8,128)** | (6,260) | (6,161) |
| Derivatives | **(1,046)** | **(9)** | (4,463) | (20) |
| Pending trades | **(150)** | **(150)** | (200) | (200) |
| | **(9,278)** | **(8,287)** | (10,923) | (6,381) |
| Net Investment Assets | **$ 112,240** | **$ 101,770** | $ 100,281 | $ 91,773 |

(i) The 2018 previously reported amounts for investments with a fair value and cost of $1,143 and $547, respectively, were reclassified from Public Equity to Private Equity.

(ii) Includes funds of $5,959 (December 31, 2018: $4,891) where the underlying assets are credit investments.

(iii) Includes resource properties with a total fair value of $33 (December 31, 2018: $135).

(iv) Includes venture capital investments of $876 (December 31, 2018: $644).

(v) Includes restricted cash of $125 (December 31, 2018: $91).

## Investment Valuation Practices

Fair values are based on quoted prices in an active market or where such pricing is not available, fair value is estimated using observable market inputs such as interest rates, quoted prices of comparable securities or unobservable inputs such as Management assumptions or contractual terms. Accredited independent external valuation experts are engaged to perform a review of Management's valuations to determine the reasonableness of the valuations for each significant private investment at least once every three years or where required using a risk-based approach. Fair values are determined as follows:

(i) Short-term deposits are recorded at amortized cost, which together with accrued interest income approximates fair value.

(ii) Nominal bonds and debentures, inflation-linked bonds and public equities are valued at year-end quoted market prices, where available. For public equities the quoted market prices are based on exchange prices while fixed income and inflation-linked bonds are based on quotes from industry standard sources. For investments, such as mortgages and private debt, where quoted market prices are not available, estimated values are calculated using discounted cash flows based on current market yields for comparable securities, independent asset appraisals, and financial analysis. Externally managed hedge funds where details of individual securities are not maintained by the OMERS Pension Plans are valued based on values provided by the fund manager and evaluated for reasonability.

(iii) Investments in private equity, infrastructure and real estate assets, held either directly or as a limited partner, generally do not have a publicly available market price. For such investments, the completion of a purchase or sale of an identical or similar investment is often the most objective determination of fair value. While not exact, valuation procedures are able to provide estimates or identify likely ranges that a reasonable counterparty would pay for such assets.

The private investments of OMERS Pension Plans are valued as follows:

- For investments that have reasonably predictable future revenue streams or that derive their value based on property or commodity values, the valuation is derived by:
  - discounting projected future cash flows of an investment using discount rates which reflect the risk inherent in the projected cash flows. Discount rates and projected cash flows are based on internal assumptions and external inputs; and
  - assessing the investment assets against the value of comparable publicly listed investments.
- For non-operating and/or start-up directly held private investments, the value may be held at cost where cost is considered the best estimate of fair value, until there is evidence to support a change in valuation.
- The fair value of a private fund investment where AC's ability to access information on underlying individual fund investments is restricted, such as under the terms of a limited partnership agreement, is equal to the value provided by the fund's general partner unless there is a specific and objectively verifiable reason to vary from the value provided by the general partner.

(iv) Fair value of derivatives, including swaps, futures, options, credit default swaps and forward contracts, are determined using quoted market prices, where available, or discounted cash flows using current market yields, where quoted market prices are not available.

## Investment Fair Value Hierarchy

Fair value measurements of investment assets and liabilities are based on inputs from one or more levels of a fair value hierarchy as follows:

*Level 1*

Fair value is based on unadjusted quoted prices in active markets for identical assets or liabilities traded in active markets. Level 1 primarily includes publicly listed equity investments.

*Level 2*

Fair value is based on valuation methods that make use of inputs, other than quoted prices included within Level 1, that are observable by market participants either directly through quoted prices for similar but not identical assets or indirectly through observable market information used in valuation models. Level 2 primarily includes debt securities and derivative contracts not traded on a public exchange, public equities not traded in an active market, public fund investments and investment related liabilities including debt and securities sold under repurchase agreements.

*Level 3*

Fair value is based on valuation methods where inputs that are based on non-observable market data have a significant impact on the valuation. Level 3 primarily includes private market investments such as real estate, infrastructure, private equity, mortgages and private debt including debt valued based on discounted future cash flow models, comparable publicly listed investments, or sales of similar investments which reflect assumptions that a market participant would use when valuing such an asset or liability. Net investment assets based on the valuation level within the fair value hierarchy are as follows:

| As at December 31, | | | | **2019** |
|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Fixed Income | **$ —** | **$ 7,043** | **$ 8,446** | **$ 15,489** |
| Public Equity | **21,080** | **—** | **—** | **21,080** |
| Private Equity | **79** | **1,094** | **21,388** | **22,561** |
| Infrastructure | **—** | **—** | **25,292** | **25,292** |
| Real Estate | **—** | **—** | **20,497** | **20,497** |
| Short-Term Instruments | **455** | **13,733** | **—** | **14,188** |
| Investment Related Assets | **4** | **2,407** | **—** | **2,411** |
| Investment Related Liabilities | **(96)** | **(9,182)** | **—** | **(9,278)** |
| Net Investment Assets | **$ 21,522** | **$ 15,095** | **$ 75,623** | **$ 112,240** |

| As at December 31, | | | | 2018 |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Fixed Income | $ — | $ 8,695 | $ 7,588 | $ 16,283 |
| Public Equity [(i)] | 18,640 | — | — | 18,640 |
| Private Equity [(i)] | 39 | 1,143 | 19,064 | 20,246 |
| Infrastructure | — | — | 20,796 | 20,796 |
| Real Estate | — | — | 22,110 | 22,110 |
| Short-Term Instruments | 3,025 | 7,324 | — | 10,349 |
| Investment Related Assets | 65 | 2,715 | — | 2,780 |
| Investment Related Liabilities | (100) | (10,823) | — | (10,923) |
| Net Investment Assets | $ 21,669 | $ 9,054 | $ 69,558 | $ 100,281 |

(i) The 2018 previously reported amounts for investments with a fair value of $1,143 were reclassified from Public Equity to Private Equity.