TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Jonathan Myers
jmyers@torys.com
P. 416.865.7532

June 23, 2023

RESS & EMAIL

Ontario Energy Board
P.O. Box 2319
27th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: Wataynikaneyap Power LP - Application for Approval of 2024 Electricity Transmission Rates (EB-2023-0168)

We are legal counsel to Wataynikaneyap Power LP, a licensed Ontario electricity transmitter. Wataynikaneyap Power LP, by its general partner Wataynikaneyap Power GP Inc. (together, "WPLP"), is pleased to submit its application to the Ontario Energy Board (OEB) for approval of an electricity transmission revenue requirement and associated transmission rates for the 2024 test year.

Please note that the application is being filed with a small number of redactions. Under separate cover, WPLP will be filing its request for confidential treatment of the underlying information in accordance with the OEB's *Practice Direction on Confidential Filings*.

If you have any questions, please do not hesitate to contact me at the number shown above.

Yours truly,

Jonathan Myers

cc: Ms. Margaret Kenequanash, WPLP
Mr. Duane Fecteau, WPLP
Mr. Charles Keizer, Torys LLP

Exhibit A, Tab 1, Schedule 1

Exhibit List

EXHIBIT LIST

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Exhibit A, Tab 2, Schedule 1

Application

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Wataynikaneyap Power GP Inc. on behalf of Wataynikaneyap Power LP ("WPLP") for an Order or Orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission of electricity.

APPLICATION

1. Wataynikaneyap Power GP Inc. ("Wataynikaneyap GP") is an Ontario corporation and the general partner of Wataynikaneyap Power LP ("Wataynikaneyap LP"), an Ontario limited partnership. Wataynikaneyap GP on behalf of Wataynikaneyap LP ("WPLP" or the "Applicant") holds an electricity transmission licence (ET-2015-0264) from the Ontario Energy Board (the "Board" or "OEB"). WPLP is seeking approval of an electricity transmission revenue requirement in respect of a single test year, commencing January 1, 2024.

2. The limited partnership interests in Wataynikaneyap LP are held 51% by First Nation LP and 49% by Fortis (WP) LP. First Nation LP is an Ontario limited partnership whose general partner is 2472881 Ontario Limited ("First Nation GP"). The limited partnership interests in First Nation LP are held directly and in equal shares by 24 First Nations (the "Participating First Nations"). Fortis (WP) LP is an Ontario limited partnership whose general partner is Fortis (WP) GP Inc. The limited partnership interests in Fortis (WP) LP are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%). With respect to the corresponding general partnerships, the shares of Wataynikaneyap GP are held 51% by First Nation GP and 49% by Fortis (WP) GP Inc. The shares of First Nation GP are held directly and in equal shares by the Participating First Nations. The shares of Fortis (WP) GP Inc. are indirectly held by Fortis Inc. (100%).

3. WPLP was established for the purposes of developing, constructing, owning and operating a new electricity transmission system, approximately 1742 km[1] in total length, in northwestern Ontario that will (i) reinforce transmission from a point near Dinorwic to Pickle Lake by means of the "Line to Pickle Lake", and (ii) provide transmission connections to remote Indigenous communities by means of the "Remote Connection Lines", which extend north of Pickle Lake and north of Red Lake (collectively, the "Transmission System").[2]

4. On April 1, 2019, the OEB granted WPLP leave to construct the Transmission System (EB-2018-0190). In addition, the OEB approved a bespoke cost recovery and rate framework for the Remote Connection Lines portion of the Transmission System, which results in a monthly fixed charge applicable to Hydro One Remote Communities Inc. ("HORCI"). The OEB also confirmed that, for the Line to Pickle Lake portion of the Transmission System, WPLP's revenue requirement will be recovered through the network charge component of the Uniform Transmission Rates ("UTRs").

5. This is WPLP's third transmission revenue requirement application. WPLP filed its first such application on April 28, 2021 in EB-2021-0134 in respect of its 2022 electricity transmission revenue requirement and associated rates effective April 1, 2022, and approval to charge HORCI a fixed charge for transmission service effective May 1, 2022. In that proceeding, the parties reached a complete settlement on all issues, which was approved by the OEB in its Decision and Order dated September 30, 2021.

6. WPLP filed its second transmission revenue requirement application on April 28, 2022 in EB-2022-0149, and updated it on July 6, 2022, in respect of its 2023 electricity transmission revenue requirement and associated rates, and to charge HORCI a fixed

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[1] All line lengths have been updated to reflect latest EPC production numbers, which in most cases reflect as-built and/or ground surveyed values. Distance related to assets that will be transferred to HORCI (~50-300m for each 25 kV segment) has been subtracted.

[2] WPLP's development, construction and operation of the Transmission System will also abide by the Guiding Principles which were approved by the leadership of the Participating First Nations.

charge for transmission service, effective January 1, 2023. In that proceeding, the parties reached complete settlement on all issues, which was approved by the OEB in its Decision and Order dated November 29, 2022. The approved Settlement Agreement provided for a total 2023 revenue requirement of $83.3 million, with recovery of $29.2 million through the UTR Network rate pool effective January 1, 2023 in respect of the Line to Pickle Lake portion of WPLP's transmission system, and recovery of $54.0 million through a monthly fixed charge of $4.5 million to HORCI effective January 1, 2023 in respect of the Remote Connection Lines portion of WPLP's transmission system. The approved Settlement Agreement included a final Revenue Requirement and Change Determinant Order reflective of the foregoing amounts.

7. In the current application, WPLP is seeking approval of its revenue requirement for the 2024 test year using a cost of service approach. WPLP anticipates filing an additional single-year cost of service revenue requirement application for the 2025 test year, followed by a multi-year revenue requirement application using an incentive-based regulatory method available to transmitters (i.e. Custom IR or Revenue Cap Index) for a period beginning with a 2026 test year. As WPLP's transmission system is expected to reach final completion during 2024, the 2026 test year represents the earliest opportunity to implement a multi-year revenue requirement framework following completion of the project.

8. The Line to Pickle Lake went into service on August 12, 2022. Given that the Line to Pickle Lake will therefore be in service throughout the 2024 test year, WPLP proposes that the OEB incorporate the associated revenue requirement for the Line to Pickle Lake into the updated UTRs for existing transmitters effective January 1, 2024.

9. The initial segments of the Remote Connection Lines (including all facilities needed to connect North Caribou Lake First Nation and Kingfisher Lake First Nation) went into service in Q4 2022. Segments associated with the seven[3] communities forecasted to be

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[3] These counts include line segments and substations associated with the Pikangikum Distribution System that were converted to a transmission supply on May 12, 2023.

connected to the Transmission System in 2023 are expected to come into service between May and November 2023. Segments associated with the remaining seven communities forecast to be connected in 2024 are expected to come into service between April and August 2024. WPLP therefore proposes to implement the monthly fixed charge to HORCI effective January 1, 2024, to reflect (a) a full year of the 2022 and 2023 in-service assets, and (b) for the new assets going into service during 2024, the relevant number of months those assets are expected to be in-service in 2024, with the total resulting revenue requirement for those new assets divided by 12 months.

10. On the basis of the foregoing, WPLP hereby applies to the OEB for orders approving:

    (a) A total revenue requirement of $165,691,082 for the 2024 test year (inclusive of the disposition of regulatory accounts as described below) and recovery thereof by means of:

        (i) the allocation to the Network UTR rate pool, the calculation of Network UTR charge determinants, and an amendment to UTRs, to allow for recovery of $37,657,460, being the portion of the total revenue requirement attributed to transmission service provided by the Line to Pickle Lake for the 2024 test year; and

        (ii) a fixed charge of $10,669,468/month, applicable to HORCI from January 1, 2024 to December 31, 2024, for recovery of $128,033,622, being the portion of the total revenue requirement attributed to transmission service provided by the Remote Connection Lines for the 2024 test year;

    (b) Partial disposition of the audited balance of the Pikangikum Distribution System Deferral Account (established by the November 22, 2018 Decision and Order in EB-2018-0267) as at December 31, 2022, including applicable forecasted interest, and the addition of the corresponding costs to WPLP's revenue requirement in respect of the Remote Connection Lines for 2024, as detailed in Exhibits H-2-1 and I-3-2;

(c) Partial disposition of the audited balances of the following accounts (established by the September 30, 2021 Decision and Order in EB-2021-0134), as at December 31, 2022, including applicable forecasted interest, as further detailed in Exhibit H-1-1:

(i) In-Service Date Variance Account;

(ii) Construction Period Interest Costs Variance Account;

(iii) Deferred Contingency Deferral Account; and

(iv) COVID Construction Costs Deferral Account;

(d) Transfer of the audited (to December 31, 2022) and unaudited (from January 1, 2023 to December 31, 2023) 2023 year-end forecast balance, together with applicable AFUDC, from the 2021-2023 COVID Construction Costs Deferral Account (the "2021-2023 CCCDA", established by the September 30, 2021 Decision and Order in EB-2021-0134) to Construction Work in Progress (CWIP) Account 2055 on December 31, 2023, and

(i) in respect of assets that are in service as of the date of this application or that are expected to come into service during the remainder of 2023, the addition to WPLP's rate base, effective January 1, 2024, of the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023; and

(ii) in respect of assets that are expected to come into service during 2024, the addition to WPLP's rate base, effective from the dates such assets come into service during 2024, of the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023;

(e) The continuation of WPLP's current deferral and variance accounts as requested in Exhibit H-1-1, subject to:

  (i) modification of CWIP Account 2055 by adding a new sub-account to track certain COVID-related capital costs that relate to the period from 2020 onward, as further detailed in Exhibit H-1-1; and

  (ii) modification of the 2021-2023 CCCDA by specifying that any amounts recorded in the account will be treated as capital and by expanding its scope by one year to include COVID-related capital costs relating to 2020, as further detailed in Exhibits H-1-1 and H-2-2;

(f) Accounting Orders establishing the following new regulatory accounts, effective January 1, 2024:

  (i) A symmetrical "Federal CIAC Variance Account" to record the revenue requirement impact of any difference between the forecasted date and the actual date that the Contribution in Aid of Construction ("CIAC") funds are distributed to WPLP under its federal funding framework, along with applicable carrying costs, as further detailed in Exhibit H-1-1; and

  (ii) An "EPC COVID-Related Costs Deferral Account" to record costs incurred and to be incurred by WPLP in respect of anticipated claims under its EPC Contract that relate to 2024 or later and which continue to be the subject of commercial discussions between WPLP and its EPC contractor, including applicable carrying costs based on the CWIP rate, as further detailed in Exhibits H-1-1 and H-2-2.

11. The evidence in support of this application has been prepared generally in accordance with the requirements set out in the OEB's *Filing Requirements for Electricity Transmission Rate Applications – Chapter 2, Revenue Requirement Applications*, dated February 11,

2016, subject to differences which reflect the unique nature of the application and the underlying transmission facilities, as described in Exhibit A-5-1.

12. The Applicant requests that copies of all documents filed with or issued by the OEB in connection with this Application be served on the Applicant and its counsel as follows:

Applicant:

Ms. Margaret Kenequanash
Chief Executive Officer
Wataynikaneyap Power
300 Anemki Place, Suite B
Fort William First Nation, ON
P7J 1H9
Tel: (807) 577-5955 ext. 105
Fax: (807) 577-5575
margaret.kenequanash@wataypower.ca

Mr. Duane Fecteau
Vice President – Finance and CFO
Wataynikaneyap Power PM Inc.
c/o FortisOntario Inc.
PO Box 1218, 1130 Bertie Street
Fort Erie, Ontario L2A 5Y2
Tel: (705) 987-3616
Fax: (705) 759-2218
Duane.Fecteau@wataypower.ca

Applicant's Counsel:

Mr. Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270
TD South Tower
Toronto, Ontario M5K 1N2
Tel: 416-865-7512
Fax: 416-865-7380
ckeizer@torys.com

Mr. Jonathan Myers
Torys LLP
79 Wellington St. W., 30th Floor
Box 270
TD South Tower
Toronto, Ontario M5K 1N2
Tel: 416-865-7532
Fax: 416-865-7380
jmyers@torys.com

13. Additional written evidence, as required, may be filed in support of this Application, which may be amended from time to time prior to the OEB's final decision.

14. The Applicant requests that the OEB proceed by way of written hearing, pursuant to Section 32.01 of the OEB's *Rules of Practice and Procedure*.

Dated at Toronto, Ontario, this 23rd day of June, 2023.

WATAYNIKANEYAP POWER GP INC.
on behalf of WATAYNIKANEYAP POWER LP

By its counsel, Torys LLP

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Jonathan Myers

Exhibit A, Tab 2, Schedule 2

Certificate of Evidence

CERTIFICATE OF EVIDENCE

The undersigned, being Duane Fecteau, Vice President Finance and CFO, hereby certifies for and on behalf of Wataynikaneyap Power LP that:

1. I am a senior officer of Wataynikaneyap Power PM Inc., duly authorized to submit this application on behalf of Wataynikaneyap Power LP;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised February 11, 2016); and
3. The evidence submitted in support of Wataynikaneyap Power LP's application for 2024 electricity transmission rates (EB-2023-0168) is accurate, consistent and complete to the best of my knowledge, and does not contain any personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31), that is not otherwise redacted in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

Dated this 22nd day of June, 2023

Duane M. Fecteau

Duane Fecteau

Exhibit A, Tab 3, Schedule 1

Executive Summary

EXECUTIVE SUMMARY

A. OVERVIEW

This is WPLP's third transmission revenue requirement application. Parts of WPLP's Transmission System went into service in the second half of 2022 and the first half of 2023. The remaining parts of the system remain under construction and are expected to come into service in stages in the second half of 2023 and during 2024. Upon completion, the Transmission System will be comprised of 22 stations and approximately 1742[1] km of lines in northwestern Ontario, which will serve to reinforce the transmission system in the region and extend transmission service to connect 16 remote First Nation communities to the provincial electricity grid.[2]

WPLP became a licensed transmitter in 2015. In 2016, construction of the Transmission System was declared by the Province of Ontario to be a priority project pursuant to section 96.1 of the *Ontario Energy Board Act, 1998*. After receiving leave to construct for the Transmission Project in 2019, WPLP secured project financing and entered into an engineering, procurement and construction ("EPC") contract following a rigorous competitive procurement process. Through those activities, the preliminary cost estimates that were presented in the leave to construct proceeding matured into cost forecasts, with significantly lower contingency amounts, which served as the foundation for WPLP's initial revenue requirement application that was approved in 2021 for the 2022 rate year. WPLP's second revenue requirement application was approved in 2022 for the 2023 rate year. WPLP's prior revenue requirement applications also described WPLP's efforts to monitor and oversee its EPC contractor's management of the construction

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[1] All line lengths have been updated to reflect the latest EPC production numbers, which in most cases reflect as-built and/or ground surveyed values. Distance related to assets that will be transferred to HORCI (~50-300m for each 25 kV segment) has been subtracted.

[2] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

impacts of the COVID-19 pandemic, which started approximately six months after the EPC contract was signed in September 2019.

Since its last rate application, WPLP has continued to diligently monitor and oversee the performance of its EPC contractor, consistent with its responsibilities under the EPC contract, including with respect to the construction schedule, cost, health and safety, and implementation by the EPC contractor of its COVID-19 Management Plan. Over the past year, significant progress has been made on the Transmission Project and in other aspects of WPLP's operations. During 2022 and the first half of 2023, all right of way clearing was completed, the Line to Pickle Lake portion of the Transmission System (described below) was energized, segments of its Transmission System that connect three communities to the grid were energized, the conversion of the Pikangikum distribution line assets to form part of the Transmission System was completed, and WPLP discussed with Valard (the EPC contractor) its amendment of the COVID-19 Management Plan to remove the majority of COVID-related restrictions while still adhering to participating First Nation COVID-19 protocols. As it relates to operational progress, WPLP executed the Inspection, Maintenance and Emergency Response Services Agreement with PowerTel Utilities Contractors Limited and the Operating Services Agreement with Hydro One Networks Inc. to provide control room services. In addition, WPLP successfully amended its Transmissions License and obtained approval for its Transmission Customer Connection Procedures (EB-2022-0330).

This Schedule summarizes WPLP's Application in respect of its transmission revenue requirement for the 2024 test year and other related approvals. Section B, below, introduces the Applicant, describes the Transmission System, provides context from prior proceedings, and sets out the specific approvals requested in this Application. Section C describes how the Transmission Project is being executed, provides summaries regarding schedule and cost, and discusses COVID-related cost impacts and their treatment. Section D summarizes the key elements of the Application, consistent with the headings and expectations set out in Section 2.3.1 of the Filing

Requirements[3], including how WPLP has addressed certain aspects of the Filing Requirements in the context of filing a single test year Application, with parts of the Transmission System already in service and parts coming into service in stages until project completion which is expected to occur in the latter part of the 2024 test year.

Historical costs presented in this Application are consistent with WPLP's December 31, 2022 audited financial statements. Cost and construction schedule forecasts for 2023-2024 reflect WPLP's revised forecasts as of May 30, 2023.

B. INTRODUCTION

1. The Applicant

WPLP is a Limited Partnership between First Nation LP, whose partnership interests are held directly by 24 Participating First Nations in equal shares, and Fortis (WP) LP, whose partnership interests are held by Fortis Inc. and indirectly by Algonquin Power & Utilities Corp.

Of the 24 Participating First Nations, which are from northwestern Ontario, 16 will be connected to WPLP's Transmission System between 2022 and 2024.[4] The Participating First Nations have been instrumental in the development of WPLP's Transmission System, and are uniquely qualified to support the ongoing engagement, communication and Indigenous participation activities that are necessary to facilitate successful project execution, construction and ongoing operation of the Transmission System.

Fortis Inc. is a diversified leader in the North American regulated electric and gas utility industry that leverages its knowledge, experience and expertise to support project management, engineering, operations, finance, regulatory and various corporate functions to support the successful construction and ongoing operation of the Transmission System.

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[3] Filing Requirements for Electricity Transmission Rate Applications – Chapter 2, Revenue Requirement Applications, dated February 11, 2016

[4] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

WPLP's ownership structure is described in further detail in Exhibit A-4-1.

2. The Transmission System

Upon completion of construction, WPLP's Transmission System will operate as a single transmission system in northwestern Ontario. One part of the system, now in service, is reinforcing transmission to Pickle Lake (the "Line to Pickle Lake"). The balance of the system, part of which is in service, will connect to the provincial power system 16 remote First Nation communities that were or continue to be served by diesel generation (the "Remote Connection Lines").[5]

The Line to Pickle Lake went into service in August 2022. It consists of: (a) a 230 kV switching station (Wataynikaneyap SS) at the location where WPLP's Transmission System connects to Hydro One's 230 kV system near Dinorwic; (b) an approximately 303 km single circuit 230 kV line running generally in a northeasterly direction from the Dinorwic area to the Pickle Lake area; and (c) a 230/115 kV transformer station (Wataynikaneyap TS) in the Pickle Lake area, which supplies WPLP's Pickle Lake Remote Connection Lines and connects to Hydro One's Pickle Lake area 115 kV transmission system.

The Remote Connection Lines are partially in service. They consist of: (a) the Pickle Lake Remote Connection Lines, comprised of approximately 903 km of single circuit 115 kV, 44 kV and 25 kV transmission lines, as well as one switching station and nine transformer stations located generally to the north of the Wataynikaneyap TS; and (b) the Red Lake Remote Connection Lines, comprised of a 115 kV switching station (Red Lake SS) at WPLP's connection to Hydro One's 115 kV system near Red Lake, as well as approximately 535[6] km of single circuit 115 kV and 25 kV transmission

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[5] One of the 16 communities, Pikangikum First Nation, became grid-connected in 2018 through an interim 44 kV connection that was converted to 115 kV on May 12, 2023, and therefore now forms part of WPLP's Transmission System. The future connection of a 17th community, McDowell Lake First Nation, would also be supported through the Remote Connection Lines.

[6] Line length reduced by 3 km compared to the previous application, as described on page 6 of Exhibit B-1-1.

lines, three additional switching stations and six transformer stations located generally to the north of the Red Lake SS.[7]

Upon completion of construction in 2024, the Remote Connection Lines will provide transmission service to the 25 kV distribution systems that are or will be owned and operated by Hydro One Remote Communities Inc. ("HORCI") in each of the 16 connecting First Nation communities.[8] [9] Exhibit B-1-1 provides detailed descriptions of the components of WPLP's Transmission System as well as a map showing the geographical location and extent of the system.

3. Key Elements of the LTC and Prior Revenue Requirement Decisions

On April 1, 2019, the OEB issued its decision and order in respect of WPLP's application for leave to construct its Transmission System (the "LTC Decision").[10] On September 30, 2021, the OEB issued its decision and order in respect of WPLP's initial transmission revenue requirement application based on a 2022 test year (the "Initial Rate Decision").[11] On November 29, 2022, the OEB issued its decision and order in respect of WPLP's transmission revenue requirement application based on a 2023 test year (the "Prior Rate Decision").[12] The following key elements provide important context for WPLP's proposals in the current application.

(a) Asset Classification[13]

The OEB determined in the LTC Decision that the Line to Pickle Lake is a network facility and that cost recovery for the Line to Pickle Lake would be through the UTR Network charge in the normal course of setting transmission rates. WPLP has therefore ensured that all costs directly

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[7] In EB-2018-0190, the OEB amended Schedule 1 of WPLP's Transmission Licence (ET-2015-0264) to reflect that the 44 kV and 25 kV segments of WPLP's Transmission System were deemed to be transmission facilities pursuant to Section 84(b) of the *Ontario Energy Board Act, 1998.*

[8] HORCI continues to work with the IPA communities. An update on progress has been provided in the Semi-Annual Report dated April 17, 2023, filed pursuant to EB-2018-0190.

[9] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

[10] EB-2018-0190, Decision and Order, April 1, 2019 (Revised April 29, 2019).

[11] EB-2021-0134, Decision and Order, September 30, 2021.

[12] EB-2022-0149, Decision and Order, November 29, 2022.

[13] LTC Decision, p. 23

related to the Line to Pickle Lake are recorded as such, and that any indirect costs included in its revenue requirement are appropriately allocated between the Line to Pickle Lake and the Remote Connection Lines.

(b) Cost Recovery and Rate Framework[14]

With respect to the Remote Connection Lines, in the LTC proceeding WPLP proposed an alternative cost recovery and rate framework that would be compatible with project-specific funding that it anticipates receiving from the federal government. The proposal was also designed to ensure that the Transmission Project, and WPLP as a utility, would be financially viable, regardless of whether such funding is ultimately received.

As part of the cost recovery and rate framework approved in the LTC Decision, the OEB approved exemptions from the provisions of the Transmission System Code that would otherwise have required HORCI to make a capital contribution towards the cost of constructing the Remote Connection Lines. Instead, WPLP will calculate a distinct revenue requirement for the Remote Connection Lines and recover that revenue requirement through a monthly fixed charge to HORCI. In accordance with regulations under the *Ontario Energy Board Act*, the expense incurred by HORCI in respect of these monthly fixed charges will form part of HORCI's revenue requirement and thereby form part of the Rural or Remote Rate Protection (RRRP) funding calculation and RRRP amounts payable to HORCI. Through this rate framework, costs associated with WPLP's Transmission System will not impact rates for customers in the connecting First Nation communities. Moreover, if funding is received under the Federal Funding Framework, some of that funding will be used to offset the impacts on the RRRP amounts that the IESO will need to recover from all Ontario transmission customers such that costs associated with WPLP's Transmission System would not be expected to impact rates for any customers in Ontario until such time as the funds of the independent Trust (established pursuant to the Federal Funding Framework) are exhausted.

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[14] LTC Decision, Section 5, pp. 24-28

The Federal Funding Framework is discussed further in Exhibit I-4-1. WPLP anticipates that any distribution of federal funds would occur at the end of 2024 and that the impact of such federal funding will be incorporated into a future application. As noted below and described in Exhibit H-1-1, to address the revenue requirement impacts of the uncertain timing for any federal funds being distributed, WPLP has proposed a new variance account in this Application.

(c) Contingency Deferral

In the Initial Rate Decision, the OEB approved a comprehensive settlement agreement, pursuant to which the parties agreed that WPLP would remove contingency amounts from its proposed rate base and establish a new deferral account to record the revenue requirement impact associated with the contingency amount removed from rate base to the extent that such contingency is realized and does not exceed the amount removed from rate base. WPLP continued with the same approach for 2023 and is proposing to maintain the approach in respect of contingency amounts in 2024.

(d) OM&A Variance

In the Prior Rate Decision, the OEB approved a comprehensive settlement agreement, pursuant to which the parties agreed that WPLP would establish a Construction Period OM&A Variance Account, asymmetrical to the benefit of ratepayers, to record the difference, if any, between the annual forecast and actual OM&A expenses during the construction period, with any shortfall in actual spending relative to forecast to be returned to ratepayers in a future proceeding. In addition, WPLP has certain additional variance accounts that were established in the Initial Rate Decision to record the impacts of variances in asset in-service dates and interest costs during the construction period. As discussed below, WPLP is proposing to maintain each of these accounts in 2024.

(e) COVID Cost Recovery

In the OEB-approved settlement agreement from the Initial Rate Decision, the parties agreed that WPLP may recover its audited 2020 year-end balance of COVID-related costs as an expense through disposition of the balance in the COVID Construction Costs Deferral Account over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025). In the Prior Rate Decision, the parties agreed that WPLP would establish a new 2021-2023 COVID Construction Costs Deferral Account to record audited year-end COVID-related costs from 2021 to 2023, with prudence and the approach to disposition to be determined in a future rate proceeding. There are several aspects to WPLP's proposals in respect of COVID-related costs in the current Application, as summarized below.

4. Approvals Requested

The primary purpose of this Application is to request approval of an electricity transmission revenue requirement for a single test year, commencing January 1, 2024. A number of related approvals are also explicitly requested, including approvals for:

- allocation of WPLP's 2024 revenue requirement between the Line to Pickle Lake and the Remote Connection Lines as set out in Exhibit I-2-1, as well as:
    - recovery of the portion of WPLP's 2024 revenue requirement allocated to the Line to Pickle Lake through adjustments to the 2024 Network UTR rate in the manner described in Exhibit I-3-1, and
    - recovery of the portion of WPLP's 2024 revenue requirement allocated to the Remote Connection Lines through a fixed monthly charge applicable to HORCI effective from January 1, 2024, as described in Exhibit I-3-2;
- partial disposition of the Pikangikum Distribution System Deferral Account, In-Service Date Variance Account, Construction Period Interest Costs Variance Account and Deferred Contingency Deferral Account, as more particularly set out in Exhibit H-2-1;[15]
- transfer of the balance from the 2021-2023 COVID Construction Costs Deferral Account to Construction Work in Progress (CWIP) Account 2055, and the addition of transferred costs to WPLP's rate base effective January 1, 2024 in respect of assets in service in

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[15] In addition, WPLP plans to continue recovery of the 2020 audited year-end balance of the COVID Construction Costs Deferral Account, for which disposition was approved over a 4-year period in the Initial Rate Decision.

2022/2023 or coming into service during 2023 and, for assets expected to come into service during 2024, effective from the actual in service date, as more particularly set out in Exhibits H-2-1 and H-2-2;

- continuation of WPLP's current regulatory accounts, subject to:
    - modification of CWIP Account 2055 by adding a new sub-account to track certain COVID-related capital costs that relate to the period from 2020 onward, as more particularly set out in Exhibit H-1-1; and
    - modification of the 2021-2023 COVID Construction Costs Deferral Account by specifying that any amounts recorded therein will be treated as capital and by expanding its scope by one year to include COVID-related capital costs relating to 2020, as more particularly set out in Exhibits H-1-1 and H-2-2; and
- Accounting Orders establishing, effective January 1, 2024:
    - a new symmetrical "Federal CIAC Variance Account", to record the revenue requirement impact of any difference between the forecasted date and the actual date that the Contribution in Aid of Construction ("CIAC") funds are distributed to WPLP under its federal funding framework, along with applicable carrying costs, as further detailed in Exhibit H-1-1; and
    - a new "EPC COVID-Related Costs Deferral Account", to record costs incurred and to be incurred by WPLP in respect of anticipated claims under its EPC contract that relate to 2024 or later and which continue to be the subject of commercial discussions between WPLP and its EPC contractor, including applicable carrying costs based on the CWIP rate, as further detailed in Exhibits H-1-1 and H-2-2.

C. PROJECT EXECUTION

1. Project Execution and Controls

To provide appropriate project controls, contract administration, risk mitigation and oversight during the construction phase, WPLP has developed a project execution structure that leverages the strengths and experience of its partners (through WPPM and OSLP[16]), supplemented by Hatch in its role as WPLP's Owner's Engineer ("OE"), and Mott MacDonald in its role as Independent Engineer ("IE"). Exhibit B-1-4 describes the role of each party in the context of WPLP's organizational and project execution structure, along with the division of responsibilities between WPLP and its EPC contractor and the processes that have been implemented in respect of project management, including risk management, oversight and project controls.

2. Construction Schedule

Following receipt of the LTC Decision in April 2019, WPLP completed all outstanding items required to initiate construction of its Transmission System. Between April 2019 and December 2019, WPLP executed its EPC contract, secured project financing and federal funding commitments, acquired the necessary outstanding permits and approvals (including EA approvals and *Far North Act* exemptions) for which it was responsible, and acquired the necessary land rights required to initiate construction. Exhibit B-1-2 provides additional detail on these pre-construction activities, while Exhibit B-1-3 summarizes the current construction schedule including the sequencing of in-service dates for all project components and segments.

Pursuant to the Settlement Agreement in EB-2021-0134, WPLP agreed to include information relating to expected community connection dates in its semi-annual reports that it files pursuant to the OEB's directions in EB-2018-0190. WPLP filed its most recent Semi-Annual Report on April 17, 2023. Subsequently, on May 30, 2023, WPLP received a further updated construction schedule from its EPC Contractor reflecting all factors known as of that date. That schedule represents the most current available construction schedule and has therefore been used as the basis for the

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[16] WPPM and OSLP are service providers as further described in Exhibit B-1-4.

current Application. Table 1, below, presents WPLP's current estimates of the energization dates for each of the remote communities, along with comparisons to the estimated energization dates that were presented in the April 17, 2023 Semi-Annual Report. As shown, the only change has been that the energization date for Sachigo Lake First Nation has been advanced by 6 months.

Table 1 – Expected Energization Dates by Community

Community	**Estimated Date from April 17, 2023 Semi Annual Report**	**Current Estimated Date**	**Difference (Months)**
Pikangikum	May-23	May-23	-
Wunnumin Lake	May-23	May-23	-
Muskrat Dam	Jul-23	Jul-23	-
Bearskin Lake	Jul-23	Jul-23	-
Wawakapewin	Jul-23	Jul-23	-
Kasabonika Lake	Aug-23	Aug-23	-
Sachigo Lake	May-24	Nov-23	(6)
KI + Wapekeka	Apr-24	Apr-24	-
Poplar Hill	Apr-24	Apr-24	-
Deer Lake	May-24	May-24	-
Sandy Lake	Jun-24	Jun-24	-
North Spirit Lake	Jul-24	Jul-24	-
Keewaywin	Aug-24	Aug-24	-

3. Project Costs

Exhibit B-1-5 provides a detailed breakdown of WPLP's current cost forecasts for the Transmission Project, with variance analysis relative to the project cost forecasts presented in the initial revenue requirement application.

In the current Application WPLP is including, as part of its total capital costs for the Transmission Project, approximately $74.6 million of known COVID-related costs that have been (and which to the end of 2023 are expected be) recorded in the 2021-2023 COVID Construction Costs Deferral Account. To the extent there may be any additional COVID-related costs for the Transmission

Project arising from the resolution of ongoing commercial discussions between WPLP and its EPC contractor, these have not been included in the capital costs presented in Exhibit B-1-5.

WPLP's current forecast of its Transmission Project capital costs (excluding the approximately $74.6 million of known COVID-related costs, and subject to resolution of the ongoing commercial discussions noted above) is $1.82 billion inclusive of interest, or $1.91 billion inclusive of the known COVID-related costs and other development and infrastructure costs (not forming part of the Transmission Project). WPLP's equivalent forecast as presented in the 2023 rate application, was $1.81 billion, or $1.82 billion inclusive of other development and infrastructure costs (but not including any COVID-related costs). As such, the primary change in the capital cost of the Transmission Project since WPLP's prior application is the inclusion of the known COVID-related costs, which in the current Application WPLP is seeking to transfer from the 2021-2023 COVID Construction Costs Deferral Account to CWIP Account 2055 as discussed below.

4. COVID-Related Impacts

Following the onset of the COVID-19 pandemic in early 2020, WPLP assessed the implications for its monitoring and oversight processes regarding its EPC contractor's management of the construction impacts of the COVID-19 pandemic, including with respect to the construction schedule, cost and efforts to mitigate such impacts. Through extensive collaboration from 2020-2022, including regular engagement and communication with the Participating First Nations, COVID-related health and safety measures were established, implemented and regularly updated to address continuing changes in the COVID environment. These efforts allowed construction to continue while mitigating risks to workers and nearby communities. Revised construction schedules were established and have continued to be updated based on construction progress. WPLP has also experienced COVID-related impacts unrelated to its EPC contract.

Subject to the outcome of the ongoing commercial discussions described below, WPLP is forecasting that, by the end of 2023, it will have incurred known COVID-19 Transmission Project costs unrelated to its EPC contract of approximately $1.4 million, and under its EPC contract of approximately $92 million. The amounts incurred under the EPC contract were approximately

$17.4 million in 2020, $68.2 million in 2021-2022, and are forecast to be approximately $6.4 million by the end of 2023. The OEB has already provided for WPLP's recovery of the 2020 amount as an expense through disposition of the COVID Construction Costs Deferral Account. WPLP proposes to treat all other COVID-related costs as capital. It is requesting in this Application to transfer the 2021-2023 amounts, which have been recorded in the 2021-2023 COVID Construction Costs Deferral Account, to CWIP and ultimately to rate base.

Notably, there may be additional COVID-related costs not included in the above amounts which are the subject of commercial discussions currently progressing between WPLP and its EPC contractor in relation to EPC costs and schedule impacts. The resolution of these discussions may result in WPLP incurring additional COVID-related costs for the Transmission Project. However, as any such costs are the subject of ongoing commercial discussions between the parties, they remain uncertain. While any such additional costs may relate to the period since the onset of the pandemic, due to their remaining uncertainty they have not been recognized by WPLP as having been incurred given the status of the commercial discussions to date.[17] As discussed in section D.10, below, WPLP is proposing to establish a new EPC COVID-Related Costs Deferral Account in which it would record any cost impacts arising from the final resolution of the commercial discussions with its EPC contractor which relate to 2024 or later, as well as to modify the 2021-2023 COVID Construction Costs Deferral Account to enable tracking of any cost impacts arising from the final resolution of the commercial discussions which relate to the 2020-2023 period.

[redacted]

D. KEY ELEMENTS OF THE APPLICATION

1. Revenue Requirement and Materiality Threshold

This Application requests approval of a 2024 test year revenue requirement of $165,691,082. Table 2, below, provides a summary of the derivation of WPLP’s revenue requirement, with references to the relevant sections of the Application that substantiate each component.

Table 2 – 2024 Revenue Requirement Summary

	LTPL	**RCL**	**Total**	**Reference**
Gross Fixed Assets (avg)	322,021,112	1,184,387,681	1,506,408,792	C-3-1
Accumulated Depreciation (avg)	-11,012,718	-22,789,830	-33,802,548	C-3-1
Net Fixed Assets (avg)	311,008,394	1,161,597,851	1,472,606,245	C-1-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	311,008,394	1,161,597,851	1,472,606,245	C-1-1
Regulated Rate of Return	6.81%	6.81%	6.81%	G-2-1
Regulated Return on Rate Base	21,164,301	79,047,405	100,211,706	G-2-1
OM&A Expenses	7,495,539	23,488,149	30,983,687	F-2-1
Property Taxes	0	0	0	F-5-1
Depreciation Expense	6,582,078	23,851,013	30,433,091	F-4-1
Income Taxes	106,014	395,958	501,972	F-5-1
Service Revenue Requirement	**35,347,932**	**126,782,524**	**162,130,456**	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**35,347,932**	**126,782,524**	**162,130,456**	
Disposition of Pikangikum Distribution System Deferral Account	0	1,899,734	1,899,734	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	3,516,436	1,526,521	5,042,957	H-2-1
Disposition of In-Service Date Variance Account (ISDVA)	-1,763,962	-2,601,017	-4,364,979	H-2-1
Disposition of Period Interest Costs Variance Account (CPICVA)	551,307	425,256	976,563	H-2-1
Disposition of Deferred Contingency Deferral Account (DCDA)	5,747	603	6,350	H-2-1
Revenue Requirement for Rates	**37,657,460**	**128,033,622**	**165,691,082**	

For transmitters requesting approval of revenue requirements greater than $10 million and less than or equal to $200 million, Section 2.1.1 of the Filing Requirements specifies a materiality threshold of 0.5% of revenue requirement. Based on the revenue requirement indicated in Table 2 above, WPLP's materiality threshold is approximately $828,000.

2. Budgeting Assumptions

WPLP's capital cost forecasts presented in Exhibit B-1-5 are largely related to its fixed price EPC contract, as well as its non-EPC costs and project development costs already incurred. Any non-EPC cost forecasts for the 2023 to 2024 period that are subject to inflationary pressures include annual inflationary adjustments of 2%.

3. Load Forecast Summary

WPLP forecasts that the Network UTR demand determinants will increase by 115.6 MW in 2024, based on the forecasted months during which 7[18] additional First Nation communities will become grid-connected in 2023 and 7 further First Nation communities will become grid connected at different times during 2024, and the electricity demand of those communities. Details of WPLP's methodology for determining the monthly demand forecast for each community are provided in Exhibit E-1-1.

In consideration of the rate framework approved by the OEB for the Remote Connection Lines,[19] WPLP has requested approval of a fixed monthly charge applicable to HORCI for service from the Remote Connection Lines. WPLP has therefore not included any Line Connection or Transformation Connection revenue requirements or charge determinants in its 2024 rate design.

4. Transmission System Plan

WPLP's Transmission Project is a major capital investment that includes the initial development, construction and in-servicing of its entire Transmission System. WPLP has carried out a

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[18] This count includes line segments and substation associated with the Pikangikum Distribution System that are already in service and transitioned to a transmission supply on May 12, 2023.

[19] See Section C.9 below for additional detail on the Remote Connection Lines rate framework.

comprehensive Transmission Project planning and development process, engaged and continues to engage extensively with potentially impacted Indigenous peoples and communities, land users and stakeholders, undertaken commercially prudent processes for construction contracting and securing necessary financing, and implemented appropriate organizational structures and processes to effectively execute the Transmission Project.

The present Application seeks approval of WPLP's transmission revenue requirement on a cost of service basis for a single test year (2024), with capital expenditure forecasts covering the 2023-2024 period during which construction of the Transmission System will be completed and the remaining project assets placed into service (in stages). The proposed revenue requirement for 2024 is therefore largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that were put into service in 2022 and the first half 2023, and are expected to go in-service in the last half of 2023, as well as the additional elements that are expected to go into service during 2024.

In granting leave to construct in EB-2018-0190, the OEB approved construction of the Transmission Project and found that its impacts with respect to price, reliability and quality of service are reasonable. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a Transmission System Plan ("TSP") or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses Exhibit 'B' of this Application to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from the construction phase to ongoing operation of the Transmission System. WPLP intends to file an initial TSP in conjunction with its first multi-year revenue requirement application following completion of the Transmission Project.

5. Rate Base

WPLP's forecasted rate base for the 2024 test year is summarized in Table 3. WPLP proposes to calculate its rate base for the 2024 test year using actual monthly in-service dates rather than using the half-year rule, due to the timing difference between different categories of assets that will be coming into service.[20] Details of in-service additions and the derivation of WPLP's rate base are provided in Exhibit 'C'.

Table 3 – 2024 Rate Base Forecast

Item	**2024 Forecast ($000's)**		
	Opening	**Closing**	**12-Month Avg**
Gross Fixed Assets	1,114,064	1,755,808	1,506,409
Less Accumulated Depreciation	(20,024)	(50,457)	(33,803)
Net Fixed Assets	**1,094,040**	**1,705,351**	**1,472,606**
Working Capital Allowance[21]	-	-	-
Total Rate Base	**1,094,040**	**1,705,351**	**1,472,606**

6. Performance and Reporting

WPLP has tracked historical reliability performance in respect of the distribution line serving Pikangikum. However, as that line operated as a distribution line until May 2023, the corresponding reliability performance data is of limited value for future comparison. A summary of that information is provided in Exhibit D-2-1.

In the approved Settlement Agreement from the Initial Rate Decision, WPLP agreed, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that were placed into service in 2022, to monitor performance on the basis of five specific reliability metrics without establishing performance targets and to report to the OEB on such performance, based on data as at Year End 2022, in approximately April 2023. WPLP filed that report with the OEB on May 12, 2023. In the approved Settlement Agreement from the Prior Rate Decision, WPLP agreed to continue to monitor performance on the same basis with respect to the additional portions of the Remote Connection Lines placed into service in 2023, and in the current Application WPLP

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[20] As permitted in Sections 2.5.1 and 2.8.10 of the Filing Requirements.

[21] See Exhibit C-4-1 for a discussion of WPLP's rationale for not including a Working Capital Allowance.

proposes to continue this for 2024. A summary of WPLP's 2022 Transmission System reliability performance is provided in Exhibit D-2-1.

WPLP has started to track information required for typical transmission scorecard measures related to safety, reliability and costs during the construction period so that this information can be used in setting future performance expectations, with consideration for any adjustments required to reflect the transition from construction to operation, as discussed in Exhibit D-1-1. WPLP intends to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year. That scorecard will propose measures that will be tracked starting in 2025, which will be the first full year that WPLP's entire transmission system is in service.

7. OM&A Expense

In its previous revenue requirement applications, WPLP described its interim O&M strategy for transitioning from a primary focus on construction of the Transmission System to an increasing focus on operations and maintenance of that system as it comes into service. As discussed in Section C of Exhibit B-1-4, WPLP has implemented the interim O&M strategy by successfully recruiting for a number of key internal positions, and competitively procuring third-party services in a manner that incorporates Indigenous Participation objectives. Of particular note is that WPLP entered into an Inspection, Maintenance and Emergency Response Services Agreement with PowerTel Utilities Contractors Limited and an Operating Services Agreement for control room services with Hydro One Networks Inc. WPLP expects that its O&M strategy will meet its immediate requirements, while continuing to evolve as additional assets are placed in service and maintenance requirements associated with those assets increase over time.

Table 4, below, summarizes the total operating costs included in WPLP's proposed 2024 revenue requirement.

Table 4 – Summary of Operating Costs

Operating Cost Category	2024 Test Year ($000's)
OM&A Expenses	30,984

Depreciation and Amortization	30,433
Income Taxes	502
Total Operating Costs	**61,919**

A portion of WPLP's OM&A expenses is directly related to operating and maintaining assets as they come into service, and provisions for outage or emergency response. These expenses will support the safe and reliable operation and maintenance of WPLP's Transmission System, with cost forecasts that are based on WPLP's experience operating its Pikangikum Distribution System since late 2018, the in-service portions of its Transmission System for which it has gained further operational experience, as well as the costs for services under agreements with its third-party service providers. The balance of WPLP's OM&A expense results from WPLP's methodology for allocating overhead costs between capital costs and OM&A expenses, as detailed in Appendix 'A' of Exhibit B-1-5. Detailed analysis of WPLP's 2024 operating costs, as well as support for WPLP's 2024 depreciation/amortization expense and income taxes, are provided in Exhibit F.

8. Cost of Capital

Through extensive negotiations with a consortium of bank lenders and the Province of Ontario, WPLP secured project financing with a relatively low effective interest rate that reduces costs for ratepayers, as further detailed in Exhibit G-2-1. Due to the variable nature of WPLP's financing facilities, WPLP has requested continuance of a variance account, approved in the Initial Rate Decision, to record the revenue requirement impact related to interest rate differentials on long-term debt, as summarized in Section 10 below.

In contrast to the 2022 and 2023 rate years, during which WPLP used a deemed capital structure for rate-making purposes comprised of 60% debt (4% short-term and 56% long-term) and 40% common equity, in the current Application, WPLP proposes to use its actual capital structure for rate-making purposes for the 2024 rate year. WPLP's use of its actual capital structure for the 2024 rate year is consistent with the terms of the Federal Funding Framework and results in savings for ratepayers. WPLP plans to revert back to using the deemed capital structure for rate-making purposes upon receiving the contribution in aid of construction (CIAC) pursuant to the Federal

Funding Framework following completion of the Transmission Project. WPLP therefore proposes to use its actual capital structure of 72.8% debt (all of which is long-term[22]) and 27.2% common equity for rate-making purposes for the 2024 rate year. WPLP's capital structure and cost of capital parameters are summarized in Table 5 below.

Table 5 – Capital Structure and Cost of Capital

	Capitalization Ratio		**Cost Rate**	**Return**
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	72.8%	$1,072,606,245	5.85%	$62,771,706
Short-term Debt	0.0%	$0	4.79%	$0
Total Debt	*72.8%*	*$1,072,606,245*	*5.85%*	*$62,771,706*
Common Equity	*27.2%*	*$400,000,000*	*9.36%*	*$37,440,000*
Total	**100%**	**$1,472,606,245**	**6.81%**	**$100,211,706**

9. Cost Allocation and Rate Design

In consideration of WPLP's unique cost recovery and rate framework, which is summarized in Section B.3 above, WPLP's 2024 revenue requirement is allocated between the Line to Pickle Lake, and the Remote Connection Lines, as summarized in Table 6 below.

Table 6 – Allocation of 2024 Revenue Requirement

	LTPL	**RCL**	**Total**
Revenue Requirement for Rates	**$37,657,460**	**$128,033,622**	**$165,691,082**

Details supporting WPLP's 2024 revenue requirement allocation, rate design and bill impacts are presented in Exhibit 'I'.

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[22] As WPLP is using its actual capital structure and all of its debt is from third parties, all debt has been allocated to long-term debt. For further details see Exhibit G-2-1.

WPLP has estimated that the UTR Network rate will increase by $0.03/kW resulting from the Line to Pickle Lake portion of its 2024 revenue requirement, as detailed in Exhibit I-3-1.

WPLP also proposes to establish a fixed monthly charge applicable to HORCI resulting from the Remote Connection Line portion of its revenue requirement. Based on the Remote Connection Lines revenue requirement and 12 months of in-service assets, the proposed monthly fixed charge is $10,669,468, effective January 1, 2024.

10. Deferral and Variance Accounts

In addition to its use of CWIP Account 2055 to record Transmission Project construction costs in accordance with the LTC Decision, WPLP has seven deferral and variance accounts that have been previously approved by the OEB. In the current Application, WPLP is proposing to (a) partially dispose of the 2022 audited year-end balances plus forecasted carrying charges for 2023 for five of the accounts, based on a 4-year disposition period for four of these accounts and a 1-year disposition period for one of these accounts;[23] (b) transfer the forecasted 2023 year-end balance of one account to CWIP Account 2055, from which WPLP is proposing to add certain of those amounts to rate base; (c) continue all of its existing accounts, subject to proposed modifications to two of the accounts; and (d) establish two new accounts. These aspects are summarized as follows.

Table 7, below, provides a summary of WPLP's existing deferral and variance account balances, including each of the sub-accounts that remain in effect as described above, as at December 31, 2022.

Table 7: Existing Regulatory Account Balances (December 31, 2022)

Account	**Principal**	**Carrying Charges (Net)**	**Total**
2055 – CWIP: Transmission Development Costs	$602,804,643	$49,522,299	$652,326,942
1508 – Pikangikum Distribution System Deferral Account	$2,826,420	$111,305	$2,937,725

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[23] This includes WPLP's plans to continue recovery of the 2020 audited year-end balance of the COVID Construction Costs Deferral Account, for which disposition was approved over a 4-year period in the Initial Rate Decision.

1508 – In-Service Date Variance Account	($15,009,351)	($185,891)	($15,195,242)
1508 – Construction Period Interest Costs Variance Account	$3,383,187	$12,595	$3,395,782
1508 – COVID Construction Costs Deferral Account	$13,148,917	$293,110	$13,442,027
1508 – Deferred Contingency Deferral Account	$21,994	$87	$22,082
1508 – 2021-2023 COVID Construction Costs Deferral Account	$68,174,054	$1,009,776	$69,183,830

In the Initial Rate Decision, the OEB approved WPLP's recovery of its audited 2020 year-end balance in the COVID Construction Costs Deferral Account (CCCDA) as an expense, including carrying charges, over a 4-year period from 2022-2025. WPLP will continue to implement this previously approved recovery in 2024.

Furthermore, WPLP is requesting partial disposition of the following four accounts: Pikangikum Distribution System Deferral Account, In-Service Date Variance Account (ISDVA), Construction Period Interest Costs Variance Account (CPICVA) and Deferred Contingency Deferral Account (DCDA), based on their December 31, 2022 audited balances and forecasted 2023 carrying charges. Consistent with the approach taken in its previous applications, WPLP is requesting a 1-year disposition period for the Pikangikum Distribution System Deferral Account. WPLP is requesting a 4-year disposition period for the ISDVA, CPICVA and DCDA to mitigate ratepayer and WPLP financial impacts, as discussed in Exhibit H-2-1.

WPLP is proposing to transfer the audited (to December 31, 2022) and unaudited (from January 1, 2023 to December 31, 2023) 2023 year-end forecast balance, inclusive of AFUDC, from the 2021-2023 COVID Construction Costs Deferral Account (2021-2023 CCCDA) to CWIP Account 2055, and to add these transferred costs[24] to rate base effective January 1, 2024 in respect of assets in service in 2022/2023 or coming into service during 2023 and, for assets expected to come into service during 2024, effective the date such assets come into service, as more particularly set out

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[24] The transferred AFUDC amounts will not be added to rate base in accordance with WPLP's federal funding framework.

in Exhibits H-2-1 and H-2-2. These amounts consist of known COVID-related costs associated with construction of the Transmission Project, which WPLP is proposing to treat as capital costs.

As the Construction Period OM&A Variance Account was established by the Prior Rate Decision effective January 1, 2023, there is no balance in the account to date and it is not reflected in the above table.

WPLP is proposing to continue all of its existing regulatory accounts, subject to the following two proposed modifications. First, WPLP is proposing to add a new sub-account to CWIP Account 2055 to track certain COVID-related capital costs that relate to the period from 2020 onward. Second, WPLP is proposing to modify the 2021-2023 CCCDA by expanding its scope to include 2020 and by specifying that amounts recorded therein will be treated as capital. These proposed modifications are described in greater detail in Exhibits H-1-1 and H-2-2.

Finally, WPLP is requesting Accounting Orders establishing two new regulatory accounts. First, it is requesting a new symmetrical “Federal CIAC Variance Account”, effective January 1, 2024, to record the revenue requirement impact of any difference between the forecasted date and the actual date that the CIAC funds are distributed to WPLP under its federal funding framework, along with applicable carrying costs. Second, it is requesting a new “EPC COVID-Related Costs Deferral Account”, effective January 1, 2024, to record costs incurred and to be incurred by WPLP in respect of anticipated claims under its EPC contract which continue to be the subject of commercial discussions between WPLP and its EPC contractor. These requests to establish new accounts are described in greater detail in Exhibit H-1-1.

Several of WPLP’s requests referred to in this section are interrelated and form part of a broader approach that is being proposed for the treatment of COVID-related costs. That approach, and the connections between these and other related elements of the Application are described in Exhibit H-2-2.

11. Bill Impacts

WPLP's proposed 2024 revenue requirement will result in bill increases from two perspectives. First, the Line to Pickle Lake portion of its revenue requirement will result in an increase of $0.03/kW to the Network UTR rate, which has a bill impact of $0.05 per month for a typical residential customer. Second, the Remote Connection Lines portion of its revenue requirement will result in increased costs to HORCI, which will ultimately be funded through an increase to the RRRP rate, which WPLP has calculated at $0.0006/kWh for 2024 and which has a bill impact of $0.48 per month for a typical residential customer.[25]

As detailed in Exhibit I-4-1, the combination of the increased Network UTR and RRRP rates arising from this Application is estimated to result in a total bill increase for a typical residential customer[26] of $0.54 per month, or 0.40%. Details of bill impacts for a typical general service customer and for transmission-connected customers are also provided in Exhibit I-4-1.

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[25] Bill increase before HST and OER adjustment.

[26] In this context, a typical residential customer is considered to be a Hydro One Networks Medium-Density (R1) customer, using 750 kWh/month on Time-of-Use rates. See Exhibit I-4-1 for details.

Exhibit A, Tab 4, Schedule 1

Corporate Structure

CORPORATE STRUCTURE

The Applicant is Wataynikaneyap Power GP Inc. (“Wataynikaneyap GP”) on behalf of Wataynikaneyap Power LP (“Wataynikaneyap LP”) (“WPLP”). The Applicant holds an electricity transmission licence (ET-2015-0264).

A. Corporate Structure

Wataynikaneyap LP is an Ontario limited partnership whose general partner is Wataynikaneyap GP. As shown in the Corporate Structure provided in **Appendix ‘A’**, the limited partnership interests in WPLP are held 51% by First Nation LP and 49% by Fortis (WP) LP. First Nation LP is an Ontario limited partnership whose general partner is 2472881 Ontario Limited (“First Nation GP”). The limited partnership interests in First Nation LP are held directly by the 24 Participating First Nations in equal shares. Fortis (WP) LP is an Ontario limited partnership whose general partner is Fortis (WP) GP Inc. The limited partnership interests in Fortis (WP) LP are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%).

With respect to the corresponding general partnerships, the shares of Wataynikaneyap GP are held 51% by First Nation GP and 49% by Fortis (WP) GP Inc. The shares of First Nation GP are held directly by the 24 Participating First Nations in equal shares. The shares of Fortis (WP) GP Inc. are owned by FortisOntario Inc. and indirectly held by Fortis Inc. (100%).

The Applicant has established a head office in the Fort William First Nation Reserve. The Participating First Nations and Fortis Inc. are described below.

1. Participating First Nations

The Participating First Nations are a group comprised of 24 First Nations from northwestern Ontario. Of the 24 Participating First Nations, 16 (as marked with an “*” below) have or will be connected to the WPLP Transmission System during the 2021-2024 construction period (the "Connecting Communities").[1] The Participating First Nations are as follows:

1. Bearskin Lake First Nation*
2. Cat Lake First Nation
3. Deer Lake First Nation*
4. Kasabonika Lake First Nation*
5. Keewaywin First Nation*
6. Kingfisher Lake First Nation*
7. Kitchenuhmaykoosib Inninuwug*
8. Lac des Mille Lacs First Nation
9. Lac Seul First Nation
10. Mishkeegogamang First Nation
11. McDowell Lake First Nation
12. Muskrat Dam First Nation*
13. North Caribou First Nation*
14. North Spirit Lake First Nation*
15. Ojibway Nation of Saugeen
16. Pikangikum First Nation*
17. Poplar Hill First Nation*
18. Sachigo Lake First Nation*
19. Sandy Lake First Nation*
20. Slate Falls First Nation
21. Wabigoon Lake Ojibway Nation
22. Wapekeka First Nation*
23. Wawakapewin First Nation*
24. Wunnumin Lake First Nation*

2. Fortis

Fortis Inc. is a well-diversified leader in the North American regulated electric and gas utility industry, with 2022 revenue of $11 billion and total assets of $64 billion as at December 31, 2022. The corporation's 9,200 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. Its regulated utilities account for approximately 99% of its total assets. FortisOntario Inc. is a wholly owned subsidiary of Fortis Inc.

WPLP's organizational structure, both for purposes of executing the Transmission System project and for transitioning into an operating utility, is described in Exhibit B, Tab 1, Schedule 4.

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[1] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

APPENDIX ‘A’

Applicant’s Corporate Structure

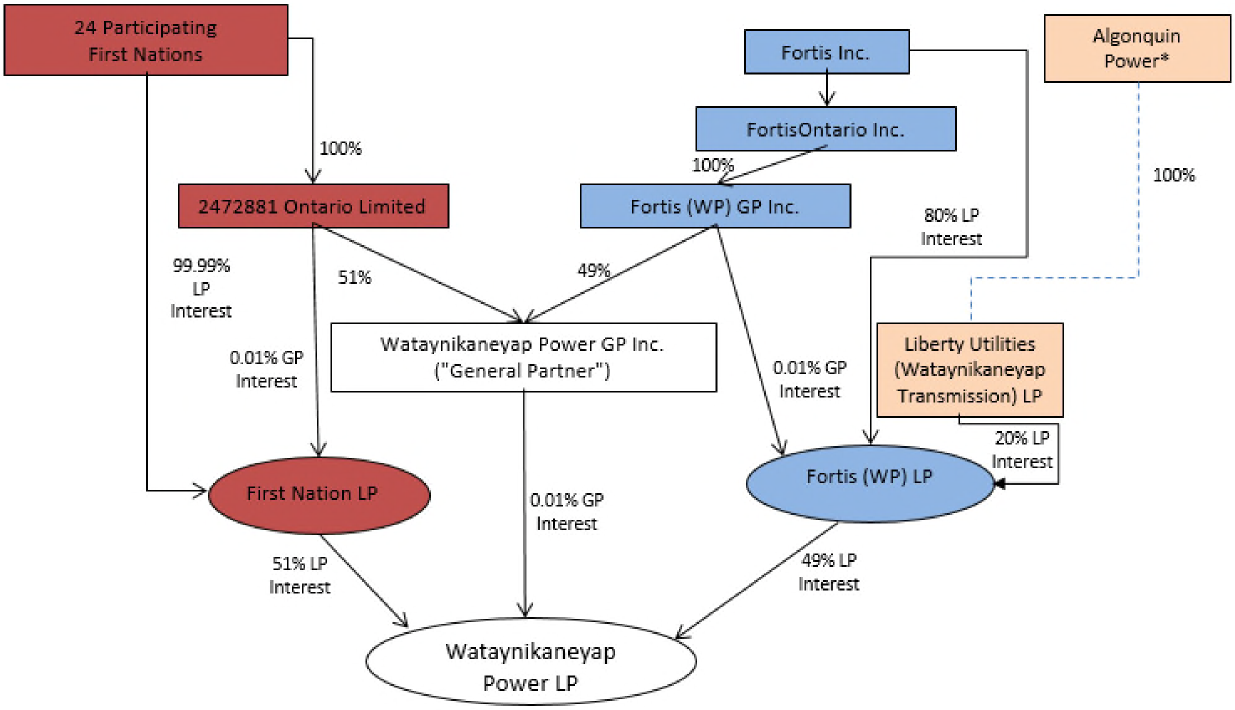
24 Participating First Nations
100%
2472881 Ontario Limited
99.99% LP Interest
51%
0.01% GP Interest
Watataynikaneyap Power GP Inc. ("General Partner")
First Nation LP
51% LP Interest
0.01% GP Interest
Wataynikaneyap Power LP
Fortis Inc.
FortisOntario Inc.
100%
Fortis (WP) GP Inc.
49%
0.01% GP Interest
80% LP Interest
Algonquin Power*
100%
Liberty Utilities (Wataynikaneyap Transmission) LP
20% LP Interest
Fortis (WP) LP
49% LP Interest

Exhibit A, Tab 5, Schedule 1

Compliance with OEB Filing Requirements

COMPLIANCE WITH OEB FILING REQUIREMENTS

WPLP has prepared this Application generally in conformance with the guidance set out in the OEB's *Filing Requirements for Electricity Transmission Rate Applications – Chapter 2: Revenue Requirement Applications* (February 11, 2016) (the "Filing Requirements"). However, due to the unique nature of the application, being for a transmission system that is partly in service and which will continue to be put into service in segments during the test year and in the year following the test year, as well as which is subject to a unique cost recovery and rate framework previously approved by the OEB - there are certain elements of the Filing Requirements that are not relevant to or compatible with the Application. These are summarized below and further addressed throughout the Application.

Section 2.4 of the Filing Requirements establish the need for evidence on asset condition, planning and prioritization of capital expenditures, as well as consideration of regional planning, which are required to be presented in a consolidated and dedicated exhibit in the application and referred to as the Transmission System Plan ("TSP"). WPLP's proposed revenue requirement is largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that have gone or are going into service in 2022 and 2023 and on the additional elements which are expected to go into service in 2024. In granting leave to construct in EB-2018-0190, the OEB approved construction of the Transmission Project and found that its impacts with respect to price, reliability and quality of service are reasonable. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a TSP or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses Exhibit 'B' of the Application to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from one that is focused on construction and execution to one that is focused on operations by the time construction is complete.

Sections 2.0 and 2.6 of the Filing Requirements discuss the value that the OEB places on cost and performance benchmarking evidence and transmission scorecards. In Exhibit A-2-1, WPLP sets out its intention to file single-year cost of service revenue requirement applications, both for the 2024 test year that is the subject of the current application and for the 2025 test year in a future application. During this period, WPLP's focus will continue to be on overseeing the completion of the construction of its transmission system and transitioning from the construction phase to operation as additional assets come into service, with a focus on cost management, risk and performance management. In Exhibit D-1-1 of this application, WPLP addresses the OEB's performance and scorecard expectations relative to WPLP's circumstances. Exhibit D-1-1 also outlines WPLP's intention to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year, and notes that the scorecard would propose measures that will be tracked starting in 2025.

WPLP's transmission assets only started being put into service in August 2022, with additional segments being put into service during 2023 and 2024. WPLP therefore expects to address transmission system reliability, including the Chapter 4 Transmission System Code requirements related to customer delivery point performance standards, in a future application. However, in an effort to be responsive to the Filing Requirements, Exhibit D-2-1 summarizes the historical reliability performance of WPLP's in-service transmission assets, as well as its Pikangikum Distribution System which was converted to form part of the transmission system on May 12, 2023.

Furthermore, pursuant to the Settlement Agreement in EB-2021-0134, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that were placed into service in 2022, WPLP agreed to monitor performance on the basis of the following reliability and operating performance metrics without establishing performance targets and to report to the OEB on such performance, based on data as at Year End 2022, which was filed with the OEB on May 12, 2023:

- Total Recordable Injuries Frequency Rate ("TRIFR") - # of recordable injuries per 200,000 hours worked, using Canadian Electricity Association definition of "recordable injuries";

- Recordable Injuries - # of recordable injuries per year, using Canadian Electricity Association definition of “recordable injuries”;
- Violations of NERC FAC-003-4 Vegetation Compliance Standard (in respect of the Line to Pickle Lake portion of the transmission system only);
- OM&A cost per kilometre of line and OM&A cost per station;
- Average system availability;
- Transmission System Average Interruption Duration Index (T-SAIDI); and
- Transmission System Average Interruption Frequency Index (T-SAIFI).

Section 2.1 of the Filing Requirements states that the average of the opening and closing fiscal year balances must be used for items in rate base. However, for those portions of its transmission system that are expected to go into service during the 2024 test year, WPLP has instead used the average of twelve-monthly values, as permitted in Sections 2.5.1 and 2.8.10 of the Filing Requirements. WPLP’s rationale for this approach is provided in Exhibit C-3-1 and is consistent with the approach used by WPLP its prior rate applications.

Section 2.1 of the Filing Requirements also includes general expectations related to including details from the most recent OEB-approved test year, historical years and a bridge year, as well as related expectations around year-over-year variance analysis. These requirements are not entirely applicable to WPLP’s current transmission rate application given the actual and expected in-service dates of assets in the 2022 historical year and the 2023 bridge year. However, Exhibit A-5-2 provides context for the Application arising from prior OEB proceedings, and Exhibits B-1-3 and B-1-5 provide schedule and cost variance analysis relative to the values previously approved by the OEB.

Sections 2.7.1 and 2.7.2 of the Filing Requirements set out the OEB’s expectations in relation to forecasting charge determinants for the UTR rate pools, including requirements for weather normalization, economic and econometric models, CDM forecasting, and historical variance analysis. Exhibit E-1-1 proposes an alternative demand forecasting methodology employed by

WPLP, in consideration of data availability and the immaterial contribution to the UTR charge determinants.[1]

Finally, Section 2.8.11.2 of the Filing Requirements requires a statement in the application as to when loss carryforwards, if any, will be fully utilized. WPLP's income tax calculations provided in Exhibit F-5-1 show that WPLP's has a significant loss carryforward for 2024, primarily resulting from Capital Cost Allowance ("CCA") deductions. WPLP does not expect to fully utilize its loss carryforwards prior to filing a multi-year revenue requirement application in 2025, and WPLP therefore proposes to address forecasting of loss carryforwards at that time.

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[1] As detailed in Exhibit E-1-1, the change in Network UTR determinants resulting from WPLP's load forecast is 0.049%, and WPLP's load forecast is not included in the Line Connection or Transformation Connection UTR charge determinants.

Exhibit A, Tab 5, Schedule 2

Summary of Prior OEB Proceedings and Directives

SUMMARY OF PRIOR OEB PROCEEDINGS & DIRECTIVES

This schedule provides a summary of the directives and expectations identified by the OEB in prior WPLP proceedings, and indicates the status of or steps taken by WPLP to respond to those aspects as part of the present Application. As this is WPLP's third transmission revenue requirement application, a number of the requirements established by the OEB in prior WPLP proceedings have already been addressed and are no longer relevant but are set out here for purposes of providing regulatory context for the Application.

A. Electricity Transmission Licence (EB-2015-0264)

On September 8, 2015, WPLP filed an application under section 60 of the OEB Act for an electricity transmission licence. On November 19, 2015, the OEB granted the licence to WPLP for a period of five years and specified that the licence shall not take effect until the date upon which the OEB is satisfied that WPLP has been selected by appropriate authorities as a developer of transmission assets in Ontario, or the date upon which the OEB, on the application of WPLP , amends schedule 1 of the licence to specify the transmission facilities to be owned and/or operated by WPLP, whichever is earlier.

B. Electricity Transmission Licence Amendment (EB-2016-0258)

On July 29, 2016, the OEB received a directive from the Minister of Energy under section 28.6.1(1) of the OEB Act requiring the OEB without a hearing to amend WPLP's transmission licence to require it to develop and seek approvals for the Line to Pickle Lake and for the Remote Connection Lines so as to enable connection of sixteen named remote Indigenous communities to the provincial electricity grid. On September 1, 2016, the OEB amended WPLP's licence to reflect the directive and amended the term of the licence to 20 years.

C. Development Costs Deferral Account (EB-2016-0262)

On August 26, 2016, WPLP applied to the OEB under section 78 of the OEB Act for an accounting order authorizing the establishment of a new deferral account to record costs incurred in relation to the development of the Wataynikaneyap Transmission Project. On March 23, 2017, the OEB approved the establishment of the account, with an effective date of November 23, 2010, which coincides with the date from which costs may be recorded in the account (being the date the 2010 Long-Term Energy Plan, which identified the Line to Pickle Lake as a priority project, was issued). The OEB specified that WPLP may not record costs relating to start-up or partnership formation, or costs incurred prior to November 23, 2010.

The OEB also specified (and OEB staff clarified by letter issued May 12, 2017) that WPLP must record in a sub-account all funding received for development activities from any source, government or otherwise, whether or not repayment is expected, so as to facilitate the future determination (at the time of disposition) as to whether any component of the costs to be recovered from ratepayers should be offset by any funding received from such other sources. OEB staff further clarified that WPLP does not need to record equity contributions from the partners of WPLP, and that the requirement to record funding applies to funding received both directly and indirectly by WPLP, where “indirectly” received funds include those received by a predecessor, affiliate or other entity related to or previously related (at the time the funding was received) to WPLP or WPGP or a predecessor, and that this includes funding received by the partners of WPLP. As noted below, in EB-2021-0134 the OEB determined based on the approved Settlement Agreement that the costs to be recovered from ratepayers should not be offset by any of the funding received from other sources, as recorded in this sub-account, and that the sub-account should therefore be discontinued.

In approving the Development Costs Deferral Account, the OEB also required WPLP to file semi-annual reports, which WPLP did under EB-2016-0262 until it commenced reporting under EB-2018-0190 in late 2019. As described below, the required content for the semi-annual reports was modified by the OEB’s decisions approving the Settlement Agreements in EB-2021-0134 and EB-2022-0149.

D. Electricity Distribution Licence (EB-2017-0236 and EB-2022-0244)

On June 15, 2017, WPLP applied to the OEB for an electricity distribution licence to support WPLP’s plan to develop, construct, own and operate an approximately 117 km distribution line between Red Lake and the Pikangikum First Nation Reserve (EB-2017-0136). WPLP indicated that there was an urgent need for grid connection of the Pikangikum First Nation on an interim basis until such time as it can be served by WPLP's Transmission System. WPLP further indicated its plan to construct the line largely to 115 kV standards, but to connect it to Hydro One's distribution system and to operate at a distribution voltage of 44 kV for a period of approximately 3-4 years from late 2018, after which it would be connected to and form part of WPLP's Transmission System. On September 28, 2017, the OEB granted the distribution licence for a 5-year term from September 28, 2017. On September 22, 2022, in EB-2022-0244, the OEB extended the term of WPLP's electricity distribution licence until June 30, 2023. The Pikangikum Distribution System was converted to form part of the Transmission System on May 12, 2023. On June 16, 2023, following WPLP's request to cancel its electricity distribution licence, the OEB confirmed that the licence was cancelled.

E. Pikangikum Distribution Costs Deferral Account and Licence Amendments (EB-2018-0267)

On September 7, 2018, WPLP applied to the OEB for an accounting order to establish a deferral account for the purpose of recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system that connects the Pikangikum First Nation to Hydro One's distribution system near Red Lake, as well as to amend WPLP's distribution licence to exempt it from metering and settlement requirements pertaining to host and embedded distributors. On November 22, 2018, the OEB approved the application. The OEB specified that the costs to be recorded in the account are the OM&A costs for the distribution system, as well as any capital costs that may be incurred after the in-service date which are not paid for by funding from Indigenous and Northern Affairs Canada (INAC)[1], including its successors. As noted above, the Pikangikum Distribution System was converted to form part of the Transmission System on May 12, 2023. In WPLP's 2023 transmission rate proceeding (EB-2022-0149), the OEB approved the continuation of the Pikangikum Distribution System Deferral Account, and the partial disposition

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[1] Now known as Indigenous Services Canada ("ISC").

of the audited December 31, 2021 account balance. WPLP's current requests related to this account are set out in Exhibit H.

F. Leave to Construct and Cost Recovery / Rate Framework (EB-2018-0190)

On June 8, 2018, WPLP applied to the OEB for leave to construct approximately 1,732 km[2] of electricity transmission and interconnection facilities, comprised of the Line to Pickle Lake and the Remote Connection Lines. The application was amended October 5, 2018 and January 28, 2019. In addition, WPLP requested approval for a unique cost recovery and rate framework under which the revenue requirement for the Remote Connection Lines would be charged through a fixed monthly service charge to Hydro One Remote Communities Inc. (HORCI) and the revenue requirement for the Line to Pickle Lake would be recovered through the Network pool of the Uniform Transmission Rates (UTRs). WPLP also requested various other relief, including a determination that the 44 kV and 25 kV segments be deemed to be transmission facilities and various exemptions from the Transmission System Code (TSC) in relation to the Remote Connection Line facilities. The OEB approved the application on April 1, 2019 (revised April 29, 2019). In the decision, the OEB directed WPLP to use CWIP Account 2055 to record construction costs and to transfer the approximately $54 million in development costs that had been recorded in the Development Costs Deferral Account to the CWIP Account. The OEB also required as a condition of approval that WPLP provide semi-annual updates to the OEB on its CWIP account and on the progress of backup supply arrangements for the connecting communities.[3]

In its decision, the OEB made a number of findings that directly related only to WPLP's initial transmission rate application, as well as other findings that continue to be relevant in the current Application. These are as follows:

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[2] As a result of minor routing changes, the total estimated transmission line distance in the current Application is approximately 1,742 km. See Exhibit B-1-1 for a description of project changes.

[3] Details and status of backup power solutions for the 16 connecting Indigenous communities are provided in WPLP's semi-annual reports, filed pursuant to OEB's Decision and Order in EB-2018-0190. The most recent semi-annual report is dated April 15, 2023.

- The OEB stated, at pp. 12-13 of the decision, that "WPLP is required to provide updated Project costs as part of its future transmission rate applications in accordance with the OEB filing requirements. The OEB requires that WPLP's first transmission rate application shall provide details of the updated costs of the Project as defined by the Owner's Engineer (actuals to date and forecasts), variance analysis of Project scope, costs and schedule compared to the original estimates, and the degree to which the Project contingency has been utilized. WPLP shall also make best efforts to provide information on any other costs that may impact this Project at the time of its inaugural rate case. Further, the OEB agrees with WPLP that any further variance analysis provided as construction progresses would consider actual or forecast costs compared to the updated cost estimates that are presented in the initial rate application." WPLP addresses these requirements primarily in Exhibit B, Tab 1, Schedule 5 and Exhibit H, Tab 2, Schedule 2.

- The OEB, on pp. 27-28 of the decision, approved WPLP's proposed cost recovery and rate framework, stating:

    - "The OEB approves the inclusion of the net capital cost associated with the Remote Connection Lines in WPLP's rate base and a monthly fixed charge applied to HORCI – in lieu of a capital contribution – to recover the capital and operating costs related to the Remote Connection Lines. The amount of the monthly fixed charge will be addressed in WPLP's transmission rate cases involving the Remote Connection Lines, when the specific elements of WPLP's revenue requirement will be approved." See Exhibit I, Tab 3, Schedule 2 of the present Application.

    - "In relation to the Line to Pickle Lake, the approved revenue requirement will be determined in WPLP's first transmission rate case involving that part of the

Project[4], for recovery through the network charge component of the UTR." See Exhibit I, Tab 3, Schedule 1 of the present Application.

- "WPLP is directed to use CWIP Account 2055 to record construction costs, a standard account included in the OEB's Uniform System of Accounts . . . Construction costs will be accumulated in the standard CWIP account for future disposition. Entries to the CWIP account will be reviewed for approval when WPLP proposes to add the related assets to rate base." WPLP indicated that it would have three sub-accounts similar to what it used in the development costs deferral account. See Exhibit C-3-1of the present Application.[5]

- "The OEB approves WPLP's request to transfer approximately $54 million in development costs to a CWIP Account. The transferred development costs will be the opening balance for WPLP's CWIP account 2055 related to this Project." See Exhibit H, Tab 2, Schedule 1 of the present Application.

- "Article 410 of the OEB's Accounting Procedures Handbook for Electricity Distributors requires that where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the OEB's published rates. Otherwise, the OEB's published rates should be used. In this case, the actual interest rate may be lower than the prescribed rate. If so, the OEB directs WPLP to use its actual cost of debt."[6] See Exhibit G, Tab 2, Schedule 1 of the present Application.

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[4] While the language in the Decision and Order refers to WPLP's first transmission rate application, this aspect needs to be determined in each transmission rate application for WPLP.

[5] In the current application, WPLP is proposing to establish a fourth sub-account to enable the tracking of incremental audited year-end COVID-related costs from 2021-2023 which are associated with assets not yet in service, as further discussed in Exhibit H-1-1.

[6] On April 18, 2019, WPLP wrote to the OEB requesting clarification of this paragraph 7 of the Order section of the April 1, 2019 Decision and Order due to the concern that it appeared inconsistent with the OEB's findings in respect of CWIP interest rates in the body of the decision. The OEB agreed and amended paragraph 7 of the Order to specify that "WPLP shall transfer the balances from its development deferral account to its CWIP account, in accordance with this Decision and Order. With respect to CWIP interest rates, WPLP shall use the

The OEB, on p. 23 of the LTC Decision and in Schedule 2 of WPLP's amended transmission licence (attached as Schedule C thereto), granted WPLP exemptions from certain sections of the TSC in relation to the Remote Connection Lines. In particular, WPLP is exempt from all sections relating to connection procedures and customer capital contributions in respect of connection facilities. The OEB originally granted these exemptions until the earlier of the date all Transmission System facilities are placed in service or December 31, 2023. In accordance with the OEB's Decision and Order in EB-2022-0330, described below, this has been extended to December 31, 2024.

G. Licence Amendments to Provide RRR Exemptions (EB-2020-0142/0143)

On May 13, 2020, WPLP filed a combined application for amendments to its electricity transmission and distribution licenses to provide WPLP with certain exemptions from the OEB's *Electricity Reporting and Record Keeping Requirements*, on a permanent basis in respect of its distribution licence (which will be in effect for a limited period to authorize operation of the Pikangikum System while operating at a distribution voltage) and on a temporary basis during the construction period in respect of its transmission licence. The OEB approved the application on August 13, 2020. In addition to the TSC related exemptions discussed above, WPLP was also exempted from certain sections of the Electricity Reporting and Record Keeping Requirements (RRR) that relate to financial disclosure obligations in respect of the 2019 to 2023 reporting periods. In accordance with the OEB's Decision and Order in EB-2022-0330, described below, this has been extended by one year.

H. 2022 Transmission Revenue Requirement Application (EB-2021-0134)

On April 28, 2021, WPLP filed its first transmission rate application seeking approval of an electricity transmission revenue requirement and associated rates, effective April 1, 2022 and to charge HORCI a fixed monthly charge for transmission service, effective May 1, 2022 (the "Initial

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lower of its actual cost of debt and the OEB's published CWIP interest rate in respect of debt that is incurred on a non-arm's-length basis, and shall use the actual cost of debt in accordance with Article 410 of the Accounting Procedures Handbook in respect of debt that is incurred on an arm's-length basis."

Rate Application”). The parties in the proceeding participated in a settlement conference and reached a complete settlement of all issues. A settlement proposal was filed and, on September 30, 2021, the OEB issued its decision approving the settlement proposal. The following outlines the key elements of the settlement agreement approved by the OEB:

- **Rate Base & Associated Deferral Account:** Establishment of a new deferral account to record the revenue requirement impact associated with the contingency amount removed from rate base, to the extent that such contingency is realized and does not exceed the amount removed from rate base.

- **COVID Cost Recovery:** Recovery of WPLP’s audited 2020 year-end balance of COVID costs as an expense through disposition of the balance in the COVID-19 Construction Costs Deferral Account (CCCDA) over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025), instead of recovering 50% of its 2020 COVID costs through revenue requirement adders in each of the 2022 and 2023 years. See Exhibit H-2-2 of the present Application.

- **Performance Monitoring and Reporting:** The timing for reporting on performance measures and specific metrics to monitor and report on with respect to reliability, including in relation to vegetation management and safety. See Exhibit D-1-1 of the present Application.

- **OM&A:** The preparation and filing by WPLP in its application for 2023 revenue requirement of benchmarking studies to compare WPLP’s (a) OM&A spending levels on a per line kilometer basis and on a per station basis relative to comparable Ontario and Canadian transmitters; and (b) compensation costs relative to Hydro One’s compensation costs. See Exhibit F-1-1 of the present Application.

- **Presentation of Evidence:** Future transmission rate applications, for years in which additional transmission line segments and stations will be placed into service, will include detailed information on variances and the use of contingency amounts for such line segments and stations being placed into service, relative to both the values presented in the respective application and the values that were presented in the Leave to Construct proceeding (EB-2018-0190). See Exhibit B-1-5 of the present Application.

I. 2023 Transmission Revenue Requirement Application (EB-2022-0149)

WPLP filed its second transmission revenue requirement application on April 28, 2022, and updated it on July 6, 2022, seeking approval for its 2023 electricity transmission revenue requirement and associated rates, and to charge HORCI a fixed charge for transmission service, effective January 1, 2023. In that proceeding, the parties reached complete settlement on all issues, which was approved by the OEB in its Decision and Order dated November 29, 2022. The following outlines the key elements of the settlement agreement approved by the OEB:

- **OM&A:** Key aspects included (i) a 5% reduction to WPLP's proposed 2023 OM&A expense on an envelope basis; (ii) establishment of a new asymmetrical Construction Period OM&A Variance Account, to the benefit of ratepayers, to be used to record the difference, if any, between the annual forecast and actual OM&A expenses, with any shortfall in actual spending relative to forecast to be returned to ratepayers in a future rate proceeding; and (iii) a commitment to file, in 2025 in respect of its application for approval of a transmission revenue requirement and rates for the period starting in 2026, an econometric benchmarking study of WPLP's OM&A costs.

- **COVID Cost Recovery:** Continued recovery of WPLP's audited 2020 year-end balance of COVID costs as an expense through disposition of the balance in the CCCDA over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025), in accordance with the OEB's decision in WPLP's 2022 revenue requirement proceeding (EB-2022-0149). In addition, establishment of a new 2021-2023 CCCDA to record audited year-end COVID-19 related costs from 2021 to 2023, with prudence and approach to disposition to be determined in a future rate proceeding. See Exhibit H-2-2 of the present Application.

- **Project/Construction Monitoring, Reporting and Coordination:** To (i) provide, in future semi-annual reports filed pursuant to EB-2018-0190, certain additional information on operational plans; (ii) provide certain notices to the OEB regarding changes to the community connection schedule, as well as to post such schedules on WPLP's website subject to alignment with other ongoing communication requirements, and (iii) on a best-efforts basis to work with HORCI on enhanced coordination of community connection processes, including with respect to the staggering of connection dates, avoidance of cold-weather outages, notices of connection and targets for asset transfers.

J. Modifications to Standard Form of Transmission Connection Agreement for Load Customers (EB-2022-0199)

In anticipation of the previously scheduled date for connecting HORCI's distribution system in Pikangikum First Nation to WPLP's Transmission System, WPLP requested approval from the OEB on June 30, 2022, for modifications to certain parts of the form of standard connection agreement set out for load customers in Appendix 1 (Version A) of the TSC (the "Standard Connection Agreement"). WPLP requested that the OEB approve such requests on an interim basis to (a) allow WPLP and HORCI to give further consideration to the modified terms that should apply in place of Schedule J of the Standard Connection Agreement, and (b) to allow WPLP to further consider the approach to such modified terms in relation to WPLP's Transmission Connection Procedures, which were under development at that time. In its Decision and Order, the OEB granted WPLP's requested modifications to the Standard Connection Agreement for its connection agreement with HORCI, on an interim basis (EB-2022-0199). The OEB required WPLP to file a final version of the modified connection agreement, including the further modifications required for Schedule J, by December 31, 2022.

K. Modifications to Standard Form of Transmission Connection Agreement, Approval of Customer Connection Procedures and Licence Amendments to Extend Code Exemptions (EB-2022-0330)

On December 16, 2022, WPLP filed an application with the OEB requesting (i) approval on a final basis for the modifications to the Standard Connection Agreement as reflected in its connection agreement with HORCI, (ii) approval of its Customer Connection Procedures (CCPs) and to amend the effective date of its CCPs as specified in WPLP's Transmission Licence to the later of September 1, 2024 and the date all facilities are placed into service, and (iii) approval to extend the period of certain TSC exemptions as specified in Schedule 2 of WPLP's Transmission Licence due to the extended project construction and in-service schedule (EB-2022-0330). On April 6, 2023, the OEB issued its Decision and Order in EB-2022-0330, granting the requested relief. In particular, the OEB approved:

- On a final basis, WPLP's proposed modifications to the Standard Connection Agreement in its connection agreement with HORCI;

- WPLP's proposed CCPs;

- an extension of the effective date for WPLP's CCPs to the later of September 1, 2024 and the date all facilities are placed into service (from the date on which all of the facilities are placed in service, or January 1, 2024, whichever is earlier);

- for the Remote Connection Lines, a one-year extension (from December 31, 2023 to December 31, 2024) to the exemptions from all sections of the TSC related to connection procedures and customer capital contributions for connection facilities and cost responsibility in relation to connecting the Listed Communities; and

- WPLP's request to extend its RRR exemption by granting a one-year extension to RRR financial disclosure obligations, which will result in the commencement of reporting in 2026, rather than 2025.

Exhibit A, Tab 6, Schedule 1

Indigenous, Métis and Customer Engagement

INDIGENOUS, MÉTIS & CUSTOMER ENGAGEMENT

WPLP recognizes that the OEB's Renewed Regulatory Framework ("RRF") and Filing Requirements contemplate that transmitters take an active role in customer engagement by initiating and carrying out customer engagement activities on an ongoing basis to obtain feedback regarding customer needs and preferences. Areas for engagement include matters such as investment planning, transmission rates and charges, system performance and outages, connection procedures, regional planning, testing and inspections. Moreover, WPLP recognizes the OEB's expectation that engagement efforts should be designed to obtain feedback from regulated distributor customers served by its transmission system, end-use load customers and generator customers served directly from the transmission system (if any), and where possible from end-use customers of distribution systems served by its transmission system.

WPLP's customer engagement efforts to date have been focused on issues relating to the design, development and construction of the Transmission System, including routing, land access, land sharing protocols and traditional protocols, through the significant Indigenous engagement activities related during the project development process and EA processes. These efforts have been undertaken by the Participating First Nations, Central Corridor Energy Group (CCEG), Tribal Councils representing member Indigenous communities, and OSLP[1] on behalf of WPLP and have been instrumental in the successful development and execution of WPLP's Transmission Project.

WPLP's extensive programs of engagement during the project development phase, and its environmental assessment processes, are described in significant detail in its leave to construct application in EB-2018-0190.[2] WPLP's subsequent engagement efforts, for the period up to its initial rate application are described in EB-2021-0134, and for the period up to its second rate application are described in EB-2022-0149).[3] WPLP's engagement efforts for the period subsequent to EB-2022-0149 are summarized in Exhibit B-1-2 of the present application. In total,

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[1] OSLP is a service provider as further described in Exhibit B-1-4.

[2] See Exhibit I of the revised application and evidence in EB-2018-0190, filed October 5, 2018 (http://www.rds.oeb.ca/HPECMWebDrawer/Record/611043/File/document).

[3] See Exhibits A-6-1 and B-1-2 of EB-2021-0134 and EB-2022-0149.

the record of engagement shows that, from 2012 to date, there have been more than 2,800 engagement activities with affected Indigenous and Métis communities conducted in various forms (e.g. open houses, meetings, etc.) in relation to the Transmission Project.

While WPLP's engagement efforts have been extensive, they differ from the approaches to customer engagement typically carried out and described in rate applications by operating utilities. In particular, WPLP's efforts have involved and continue to involve engagement with connecting and otherwise affected First Nations, land users and private landowners affected by the Transmission System routing and construction, as well as consultations with a wide range of potentially impacted stakeholders. These stakeholders have included a number of federal, provincial and local governments and regulatory agencies, the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI) and Hydro One Remote Communities Inc. (HORCI). Much of WPLP's early engagement efforts,[4] focused on identifying and supporting the need to connect remote Indigenous communities to the transmission system as an alternative to the continued use of diesel generation. Discussions of electricity supply limitations related to diesel generators and the impacts on the Indigenous communities are provided in WPLP's leave to construct application in EB-2018-0190.[5] Much of WPLP's engagement has also been carried out in the context of the project development activities and the environmental assessment processes for the Line to Pickle Lake and the Remote Connection Lines that are described and referenced above.

The Line to Pickle Lake portion of the Transmission System was energized via a connection to HONI's transmission system in Dinorwic on August 12, 2022 and has since been connected to HONI's 115 kV transmission system in Pickle Lake. This portion of the Transmission System reinforces transmission in the region but does not serve any customers directly at this time. The Remote Connection Lines directly serve one customer, HORCI, which is or will be the licensed

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[4] Including the significant efforts of the predecessor organizations to WPLP, including CCEG.

[5] See Exhibit C-1-1 of the revised application and evidence in EB-2018-0190, filed October 5, 2018 (http://www.rds.oeb.ca/HPECMWebDrawer/Record/611043/File/document)

distributor in respect of each of the sixteen connecting Indigenous communities.[67] These connections are occurring over an approximately 3-year period as different segments of the Remote Connection Lines are completed and commissioned, with the first 2 communities having been connected in 2022, 7 communities expected to connect in 2023[8] and the remaining 7 communities expected to connect in 2024.

WPLP has undertaken significant engagement with HONI and HORCI throughout the process of developing and constructing the Transmission System, in anticipation of placing the initial segments into service in 2022, and on an ongoing basis as construction and community connections continue. This has included regular discussions in the context of developing and obtaining leave to construct and approval for the unique cost recovery and rate framework that will apply, as well as in the context of developing, obtaining approvals for and operating the Pikangikum Distribution Line.[9] In addition, during the course of the development and hearing of the initial transmission rate application, WPLP engaged with HORCI regarding matters such as the calculation and mechanics of the fixed monthly charge in respect of the Remote Connection Lines. Moreover, as part of the approved Settlement Agreement in EB-2022-0149, WPLP and HORCI agreed to cooperate and coordinate in circumstances where connecting communities request meetings or presentations prior to community connection dates.

Since the 2023 revenue requirement application, WPLP has continued to coordinate with HONI on matters relating to construction, commissioning and energization at each of the locations where WPLP's transmission system will connect with HONI's transmission system. Similarly, WPLP has worked with HORCI to coordinate procurement, construction, commissioning and energization activities for distribution delivery points, with a focus on the communities that will

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[6] HORCI continues to work with the Independent Power Authorities ("IPA") communities. WPLP has filed the latest IPA update provided by Indigenous Services Canada in connection with its Semi-Annual Report dated April 17, 2023 in EB-2018-0190.

[7] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

[8] This includes Pikangikum First Nation, supplied by the Pikangikum Distribution System that was converted to form part of the Transmission System on May 12, 2023.

[9] See EB-2018-0267.

be connecting in 2023. WPLP's engagement and coordination activities with HONI and HORCI have also included the drafting of transmission connection agreements, confirmation of settlement processes, and completion of relevant IESO registration processes.

WPLP participated in the IESO's Regional Planning process, which resulted in the publication of the Northwest Integrated Regional Resource Plan (IRRP) in January 2023, and it is currently participating in the Northwest Regional Infrastructure Planning (RIP) process led by HONI. WPLP's participation in these processes has been focused on ensuring that all options are being considered and investigated to accelerate the transfer of load in the Pickle Lake area from HONI's E1C transmission line to WPLP's transmission system (via HONI's new Pickle Lake SS). This load transfer will significantly increase capacity in both the Red Lake and Pickle Lake subsystems and is also expected to improve reliability for Indigenous communities currently supplied from HONI's E1C transmission line.

As construction of various transmission line segments nears completion, WPLP has initiated community engagement activities that include, but are not limited to, engagement on permanent access for operational purposes for the project, updates on project status, archaeology, health and safety, permitting, land access, IPA transfer, backup power, and Indigenous participation, along with community-specific questions and feedback. Discussions at each community engagement session have included an update on construction status, an overview of the scope of WPLP's operational and maintenance activities and details of how WPLP proposes to access transmission right of way through a combination of a permanent access for operating purposes and temporary access methods. This process provides an opportunity for Indigenous community members and land users to understand and comment on WPLP's access plans, and for WPLP to adjust its access plans based on the input provided.

As WPLP continues to transition into being an operating transmitter with connected customers, it will develop and implement customer engagement processes that address the OEB's expectations for customer engagement by transmitters in a manner that is appropriate for its circumstances. Those processes and the customer needs and preferences identified through implementation of those processes will be described in connection with WPLP's first Transmission System Plan, which is expected to be included in a future transmission rate application by WPLP. In the interim, WPLP will continue to identify and take into consideration the customer, community and land user needs and preferences it identifies through its ongoing engagement with Indigenous Peoples and communities, HONI, HORCI and others.

Exhibit A, Tab 7, Schedule 1

Financial Information

FINANCIAL INFORMATION

This schedule provides the financial information specified in the OEB's Filing Requirements. Included are the following:

- Attachment 1 – WPLP Audited Financial Statements for 2022
- Attachment 2 – WPLP Audited Financial Statements for 2021
- Attachment 3 – WPLP Tax Returns for 2022
- Attachment 4 – WPLP Tax Returns for 2021
- Attachment 5 – 2022 Annual Report for Fortis Inc.[1]

A. Accounting Standard

WPLP follows the Canadian Accounting Standards for Private Enterprises (ASPE) and has used that standard as the basis for this Application. WPLP previously informed the OEB that it follows ASPE on December 19, 2016, in the proceeding to establish its Development Cost Deferral Account (EB-2016-0262).[2]

Authorization to use the ASPE is not required by a Canadian securities regulator. As a profit-oriented entity whose debt and equity instruments are not publicly traded, WPLP is eligible to apply ASPE for financial reporting and rate regulated accounting under Part II of the *CPA Canada Handbook – Accounting*. The use of ASPE for rate setting and regulatory reporting purposes results in consistency between WPLP and affiliates of FortisOntario Inc., allowing efficient implementation of accounting systems and reporting processes through a Services Agreement between WPLP and FortisOntario Inc.[3]

WPLP has had no changes to its accounting policies or accounting standards since its last revenue requirement application. WPLP's capitalization policy under ASPE is provided in Exhibit C-6-1.

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[1] First Nation LP does not prepare an equivalent annual report.

[2] EB-2016-0262; IRRs filed December 19, 2016; response to IR Board Staff – 15 a)

[3] See Exhibit F-3-1 for additional details on shared services.

B. Existing Accounting Orders

Exhibit H-1-1 provides a comprehensive summary of WPLP's existing regulatory accounts, including references to the OEB accounting orders establishing to those accounts.

C. Other Financial Information

WPLP does not engage in non-utility business and is therefore not required to segregate any portion of its fixed assets or financial results.

As described in Exhibit G of this Application, WPLP has secured project-specific debt financing. WPLP's partners, First Nation LP and Fortis (WP) LP, made equity contributions in 2022 as the initial assets went into service, and they are planning to make additional equity contributions in 2023 coinciding with additional assets going in service. Filing Requirements related to rating agency reports, prospectuses and information circulars are therefore not applicable.

ATTACHMENT 1

WPLP Audited Financial Statements for 2022

Wataynikaneyap Power LP

Financial statements
December 31, 2022

Building a better
working world

Independent auditor’s report

To the Directors of
Wataynikaneyap Power LP

Opinion

We have audited the financial statements of **Wataynikaneyap Power LP** [the “Partnership”], which comprise the balance sheet as at December 31, 2022, and the statement of partners’ equity, statement of operations and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2022, and its results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

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 financial statements* section of our report. We are independent of the Partnership in accordance with the other ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Partnership’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 the Partnership or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Partnership’s financial reporting process.

Auditor’s responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the 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 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 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 the Partnership’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 the Partnership’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 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 the Partnership to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
April 25, 2023

Balance sheet

As at December 31

	2022	2021
	$	$
Assets		
Current		
Cash *[note 7]*	**35,045,432**	35,980,389
Prepaid expenses	**20,038**	—
Accounts receivable	**5,248,463**	227,528
Inventory	**4,299,104**	384,068
HST receivable	**1,954,155**	3,322,137
Due from related parties *[note 3]*	**17,114**	7,651
Total current assets	**46,584,306**	39,921,773
Regulatory assets *[notes 1 and 2]*	**88,981,445**	62,740,562
Property, plant and equipment, net *[note 4]*	**1,380,524,270**	968,527,983
	1,516,090,021	1,071,190,318
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**216,444,170**	170,637,647
Due to related parties *[note 3]*	**3,825,830**	11,981,756
Total current liabilities	**220,270,000**	182,619,403
Long-term debt *[note 5]*	**945,213,697**	818,344,443
Regulatory liabilities *[notes 1 and 2]*	**15,195,242**	—
Deferred contributions *[note 6]*	**51,970,846**	53,285,819
Total liabilities	**1,232,649,785**	1,054,249,665
Partners' equity	**283,440,236**	16,940,653
	1,516,090,021	1,071,190,318

See accompanying notes

Approved by the Directors:

Director J. Scott Hawkes Director

Statement of partners' equity

Year ended December 31

	2022				2021
	First Nation LP 51.00%	Fortis (WP) LP 48.99%	Wataynikaneyap Power GP Inc. 0.01%	Total	Total
	$	$	$	$	$
Partners' equity (deficiency), beginning of year	**9,295,879**	**7,645,101**	**(327)**	**16,940,653**	16,496,817
Cancellation of LP units	**(2,919,059)**	**(1,929,995)**	**—**	**(4,849,054)**	—
Issuance of LP units	**129,374,545**	**124,761,893**	**—**	**254,136,438**	—
Contributed surplus	**2,473,018**	**2,375,552**	**484**	**4,849,054**	—
Net income for the year	**6,305,204**	**6,056,705**	**1,236**	**12,363,145**	443,836
Partners' equity, end of year	**144,529,587**	**138,909,256**	**1,393**	**283,440,236**	16,940,653

See accompanying notes

Wataynikaneyap Power LP

Statement of operations

Year ended December 31

	2022 $	**2021** $
Revenue		
Transmission	**25,071,060**	—
Pikangikum capital contribution amortization *[note 6]*	**1,237,590**	1,238,745
Regulatory interest, net	**1,126,160**	761,092
Interest income	**53,933**	1,035
	27,488,743	2,000,872
Expenses		
Operations	**1,318,308**	—
General and administration	**2,638,196**	318,291
Operating financing costs	**4,939,252**	—
Regulatory financing costs	**1,887,789**	—
Amortization	**4,342,053**	1,238,745
	15,125,598	1,557,036
Net income for the year	**12,363,145**	443,836

See accompanying notes

Statement of cash flows

Year ended December 31

	2022	2021
	$	$
Operating activities		
	12,363,145	443,836
Add (deduct) item not affecting cash		
Non-cash regulatory interest	**(1,126,160)**	—
Amortization of deferred contributions	**(1,237,590)**	1,238,745
Amortization of property, plant and equipment	**4,342,053**	(1,238,745)
Changes in regulatory assets and liabilities	**(9,919,481)**	—
Changes in non-cash working capital balances related to operations		
Accounts receivable	**(5,020,935)**	(222,001)
Prepaid expenses	**(20,038)**	—
Inventory	**(3,915,036)**	12,736
HST receivable	**1,367,982**	1,635,084
Due from/to related parties	**(8,165,389)**	10,352,417
Accounts payable and accrued liabilities	**45,806,523**	54,479,314
Cash provided by operating activities	**34,475,074**	66,701,386
Investing activities		
Regulatory assets and liabilities	—	(60,693,596)
Purchases of property, plant and equipment	**(416,338,340)**	(447,380,528)
Cash used in investing activities	**(416,338,340)**	(508,074,124)
Financing activities		
Decrease in deferred contributions	**(77,383)**	(33,712)
Issuance of LP units	**254,136,438**	—
Increase in long-term debt	**126,869,254**	467,627,779
Cash provided by financing activities	**380,928,309**	467,594,067
Net increase (decrease) in cash during the year	**(934,957)**	26,221,329
Cash, beginning of year	**35,980,389**	9,759,060
Cash, end of year	**35,045,432**	35,980,389

See accompanying notes

Notes to financial statements

December 31, 2022

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP [the "Partnership" or "WPLP"] was formed and registered under the laws of the Province of Ontario [the "Province"] by First Nation LP, Fortis (WP) LP and Wataynikaneyap Power GP Inc., through a limited partnership agreement dated July 6, 2015 and shall adhere to the following Guiding Principles:

[i] Our people expect that the Wataynikaneyap Power Project will be undertaken in a manner that respects our lands, rights and principles; our way of life on the land and as part of the land; and our land sharing protocols.

[ii] Our sacred responsibilities given to us by the Creator are to protect the land, which protects us in return. Therefore, the Project shall be built, operated and maintained in a way that minimizes adverse environmental impacts, as follows:

- The Project shall not poison the lands;
- No herbicides shall be used throughout the life of the transmission line to control vegetation;
- The Project shall be constructed, operated and maintained in a manner that observes and does not interfere with seasonal hunting, trapping, fishing and harvesting and keeps disturbances to a minimum;
- No new transmission lines shall be located underwater; and
- The Project will develop and implement an environmental and social management plan which will include acceptable and effective mitigation measures for any sacred sites, gathering sites and harvesting sites.

[iii] The Project shall respect confidentiality and comply with any conditions of use for any Traditional Land and Resource Use information provided by the communities, including intellectual property.

[iv] Our communities must maintain decision-making and ownership and receive benefits in the Project1

The Partnership ownership interests are the following:

First Nation LP – 51.0%
Fortis (WP) LP – 48.99%
Wataynikaneyap Power GP Inc. – 0.01%

Fortis (WP) LP is owned 80% by Fortis Inc. and 20% by Liberty Utilities (Wataynikaneyap Transmission) LP as at December 31, 2022. The shares of First Nation LP are held directly by 24 Participating First Nations in equal shares.

On August 1, 2015, Wataynikaneyap Power Corporation transferred the project assets of the Wataynikaneyap transmission project [the "Project"] to WPLP for $15,759,486, and WPLP assumed notes payable totaling this same amount as consideration for the transfer.

The business of WPLP is the planning and development of the Project, which consists of a new transmission system in northwestern Ontario, to reinforce transmission to Pickle Lake and to connect remote First Nation communities that are currently served by diesel generation. WPLP is a licensed Ontario electricity transmitter and is regulated by the Ontario Energy Board ["OEB"].

The Province identified the Project as a priority in the 2010 and 2013 Long-Term Energy Plans [“LTEP”]. The Province declared in the 2013 LTEP that the connection of remote First Nation communities is a key step towards providing a reliable, clean and affordable energy future for everyone in the Province. Further declaration of support was provided in the 2017 LTEP; the Project was noted as being selected as the transmitter for connecting remote First Nation communities.

On July 20, 2016, the Lieutenant Governor in Council made an Order in Council pursuant to Section 96.1 of the *Ontario Energy Board Act* [the “Act”] declaring the construction of an electricity line originating at a point between Ignace and Dryden and terminating in Pickle Lake, and the construction of electricity transmission lines extending north from Pickle Lake and Red Lake required to connect certain remote communities, to be a priority project.

On June 2, 2016, the Ontario Legislature passed the *Energy Statute Law Amendment Act, 2015* [also referred to as “Bill 135”]. Bill 135 permitted Cabinet to designate WPLP on July 20, 2016 as the electricity transmitter to connect 16 remote First Nation communities that currently rely on diesel power to the Province’s electricity grid.

The Lieutenant Governor in Council made an Order in Council on July 20, 2016 approving a Directive issued by the Minister of Energy pursuant to Section 28.6.1 of the Act, which required the OEB, without holding a hearing, to amend the conditions of WPLP’s electricity transmission license to include a requirement that WPLP proceed to develop and seek approvals for the Project.

On November 1, 2016, the Minister of Energy issued a letter to WPLP indicating that the Government of Ontario is committed to working with all First Nation communities in Ontario that are diesel reliant. The Government of Ontario has identified 21 diesel-reliant communities for whom grid connection makes economic sense, of which 16 are included in the Project. WPLP is fully supportive of improving the living conditions for all diesel reliant First Nation communities by continuing to proceed with the Project to economically expand Ontario’s electricity grid. McDowell Lake First Nation is one of the First Nation shareholders and has expressed a desire to become connected to the Project. WPLP will pursue options, as a licensed transmitter, to provide economic means to connect McDowell Lake to the Project and has initiated discussions with the Government of Ontario in this regard.

Basis of accounting

These financial statements have been prepared in accordance with Part II of the *CPA Canada Handbook – Accounting*, “Accounting Standards for Private Enterprises” [“ASPE”], which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada. The financial statements reflect the financial position and results of WPLP. These financial statements do not include the assets, liabilities, revenue and expenses of the partners. No provision has been made in these financial statements for any income taxes that may be assessable to the partners. Further, no provision has been made in the accounts for any salaries or interest accruing to the partners.

Summary of significant accounting policies

Regulation

WPLP is a licensed Ontario electricity transmitter and is regulated by the OEB.

On August 26, 2016, WPLP applied to the OEB for an Accounting Order authorizing WPLP to establish a new regulatory deferral account for the purpose of recording costs in relation to the development of the Project.

On March 23, 2017, the OEB issued its Decision and Order on the deferral account proceeding. The effective date for the new deferral account was established as November 23, 2010. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable Project costs at regulated interest rates prescribed by the OEB. As a result of the Decision and Order, the OEB has denied all Project costs incurred prior to November 23, 2010, as well as any start-up and partnership formation costs from being included in the deferral account.

On November 22, 2018, the OEB issued its Decision and Order on the deferral account for recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable operation, maintenance and administration costs for the distribution system, as well as any costs that may be incurred after the in-service date, which are not paid for by Indigenous Services Canada, at regulated interest rates prescribed by the OEB.

On April 1, 2019, the OEB issued its Decision and Order on the leave to construct application to construct transmission lines and associated facilities in Northwestern Ontario. As part of the Decision and Order, the OEB approved the transfer of development costs to WPLP's construction work-in-progress ["CWIP"] account, and all future project construction costs are to be recorded in the CWIP account.

Prior to April 1, 2019, costs determined to be Project development costs were deferred as regulatory assets on the balance sheet. All non-Project costs are recognized on the statement of operations. Future transmission rate proceedings will determine the proper disposition of all Project costs.

On September 30, 2021, the OEB issued its Decision and Order on the inaugural rate application filed by WPLP for the 2022 test year in April 2021. As part of the Decision and Order, the OEB approved the discontinuance of the CWIP Funding subaccount used to track funding amounts without applying the amounts recorded in that subaccount as offsets to development and construction costs. The OEB further approved the establishment of four new deferral/variance accounts: In-Service Date Variance Account ["ISDVA"], Construction Period Interest Costs Variance Account ["CPICVA"], Deferred Contingency Deferral Account ["DCDA"] and the COVID Construction Cost Deferral Account ["CCCDA"].

On November 29, 2022, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2023 test year in April 2022. As part of the Decision and Order, the OEB approved the continuance of the ISDVA, CPICVA and DCDA accounts, and the establishment of two new variance accounts: Construction Period OM&A Variance Account ["CPOMAVA"] and 2021-2023 COVID Construction Costs Deferral Account ["2021-2023 CCCDA"].

Revenue recognition

Revenue from the transmission of electricity is recognized on the accrual basis. Transmission revenue is based on revenue requirement that is submitted through the annual rate application and subsequently approved by the OEB. Approved revenue requirement includes a rate of return along with other cost recoveries necessary to support the Partnership's transmission system. Unbilled revenue included in accounts receivable as at December 31, 2022 is $5,048,410 [2021 – nil].

As noted above, WPLP is allowed regulatory carrying charges on the amount of deferred Project costs and thus recognizes interest income when earned on the balance of such costs. Expense recoveries are recognized as revenue in the year in which recovery is identified and collectability is assured.

Inventory

Inventory, consisting of material and supplies, is measured at the lower of weighted average cost and net realizable value.

Property, plant and equipment

Property, plant and equipment are initially measured at cost and subsequently measured at cost less accumulated amortization.

Property, plant and equipment are amortized over the respective asset's useful life using the following methods and rates:

	Method	Estimated useful life
Transmission plant		
Land rights	Straight-line	40 years
Station equipment – transformers & stations	Straight-line	50 years
Station equipment – switches & breakers	Straight-line	40 years
Station equipment – protection & control	Straight-line	20 years
Towers and fixtures	Straight-line	60 years
Poles and fixtures	Straight-line	45 years
Overhead conductors and devices	Straight-line	45 years
General plant		
Office furniture and equipment	Straight-line	10 years
Computer hardware	Straight-line	5 years
Transportation equipment	Straight-line	5–10 years

Income taxes

As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no income taxes are recognized in WPLP's financial statements.

Financial instruments

When WPLP becomes a party to the contractual provisions of a financial instrument, WPLP recognizes the financial asset or financial liability at its fair value, except for related party transactions, which are at the carrying or exchange amount depending on the circumstances. WPLP recognizes its transaction costs in income in the period incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their origination, issuance or assumption. Subsequently, WPLP measures its financial instruments at amortized cost. WPLP does not own any equity instruments that would be subsequently measured at fair value if quoted in an active market or at cost less impairment for equity instruments not quoted in an active market. Financial assets measured at amortized cost include cash, accounts receivable and due from related parties.

Notes to financial statements

Use of estimates

The preparation of financial statements in conformity with ASPE and the regulatory environment in which the Company operates requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions or other regulatory proceedings. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in income in the period in which they become known. Significant estimates and assumptions that are made by management are used for, but not limited to, the valuation of regulatory assets.

2. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management costs.

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in WPLP's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. WPLP continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future transmission rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the OEB at the quarterly approved deferral and variance prescribed interest rate [bankers' acceptances – three months plus 0.25 spread]. WPLP currently only accrues interest on regulatory costs that have been netted against third-party funding received. On September 30, 2021, the OEB approved the transfer of coronavirus disease ["COVID-19"] costs incurred to December 31, 2020 to a deferral account in the Decision and Order EB-2021-0143. On November 29, 2022, the OEB approved the establishment and transfer of COVID-19 costs incurred in 2021 to a deferral account in the Decision and Order EB-2022-0149. As a result, COVID-19 costs relating to 2021 were transferred during the year to the new deferral account.

Long-term regulatory assets and liabilities consist of the following:

	2022 $	2021 $
Long-term regulatory assets		
Distribution system deferral account	**2,937,724**	3,243,928
COVID Construction cost deferral account – 2020	**13,442,027**	17,498,830
COVID Construction cost deferral account – 2021 to 2023	**69,183,830**	41,997,804
Construction period interest costs variance account	**3,395,782**	—
Deferred contingency deferral account	**22,082**	—
Total long-term regulatory assets	**88,981,445**	62,740,562

	2022 $	2021 $
Long-term regulatory liabilities		
In-Service date variance account	**15,195,242**	—
Total long-term regulatory liabilities	**15,195,242**	—

Distribution system deferral account

This account records the costs incurred in relation to the Pikangikum System from the in-service date of the Pikangikum System up to the date the Pikangikum System is converted into and thereafter forms part of WPLP's transmission system. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the 2021 balance as at December 31, 2021, which is being collected through revenue requirement adders in 2023.

Construction period interest costs variance account

This account records the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in rate application and WPLP's actual effective interest rate on long-term debt during the construction period. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The balance in this account will be brought forward for disposition in a future proceeding with the OEB.

COVID Construction cost deferral account – 2020

This account records all the incremental development and constructions costs that are directly attributable to the COVID-19 pandemic incurred after March 11, 2020. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of WPLP's CCCDA 2020 account balance as at December 31, 2020, which is being collected through revenue requirement adders over a four-year period ending December 31, 2025.

COVID Construction cost deferral account – 2021 to 2023

This account records all the incremental development and construction costs that are directly attributable to the COVID-19 pandemic incurred from 2021 to 2023. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts; however, interest will ultimately be dependent on the OEB's determination as to the approach to disposition of the recorded amounts as capital or as an expense. The balance in this account will be brought forward for a prudency review and disposition in future rate application proceedings.

Deferred contingency deferral account

This account records the revenue requirement impact attributable to contingency costs associated with 2022 in-service asset additions limited to a maximum of $48,075,777. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The balance in this account will be brought forward for prudency review and disposition in a future rate application proceeding.

In-Service date variance account

This account records the difference between WPLP's approved revenue requirement based on forecasted in-service dates for the various lines/stations consisting of the transmission system and the revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. This account shall be symmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The balance in this account will be brought forward for disposition in a future proceeding with the OEB.

3. Related party transactions

During the year, WPLP entered into the following transactions with related parties:

	2022 $	**2021** $
Project costs paid on behalf of WPLP by		
FortisOntario Inc.	**1,918,674**	1,325,445
First Nation LP	**245,503**	—
Newfoundland Power Inc.	**56,657**	54,244
Opiikapawiin Services LP	**6,529,746**	5,238,526
Wataynikaneyap Power PM Inc.	**5,287,262**	3,558,977
	14,037,842	10,177,192
Project engagement fees billed to WPLP by First Nation LP	**578,313**	551,807
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**578,313**	551,807

	2022 $	2021 $
Receipts (payments)		
Opiikapawiin Services LP	**(6,203,276)**	(3,392,707)
FortisOntario Inc.	**(1,707,061)**	(1,264,723)
Wataynikaneyap Power PM Inc.	**(5,528,118)**	(4,046,407)
Newfoundland Power Inc.	**(56,657)**	(54,244)
First Nation LP	**(594,044)**	(622,786)
	(14,089,156)	(9,380,867)

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

As at December 31, the amounts due from (to) related parties are as follows:

	2022 $	2021 $
Current due to related parties		
Opiikapawiin Services LP	**(2,106,780)**	(2,680,311)
First Nation LP	**(102,650)**	(93,180)
First Nation LP third-party funding	**(245,503)**	(8,386,438)
Wataynikaneyap Power PM Inc.	**(927,004)**	(589,547)
FortisOntario Inc.	**(443,893)**	(232,280)
	(3,825,830)	(11,981,756)

	2022 $	2021 $
Current due from related parties		
Wataynikaneyap Power GP Inc.	**2,506**	2,506
Fortis (WP) GP Inc.	**2,178**	2,340
Fortis (WP) LP	**1,885**	2,805
Opiikapawiin Services LP	**10,545**	—
	17,114	7,651

The amounts due from related parties are unsecured, non-interest bearing and have no specified terms of repayment.

As part of the OEB Decision and Order EB-2021-0134 on the initial rate application, WPLP was instructed to discontinue the CWIP Funding subaccount without applying the amounts recorded in that subaccount as offsets to development and construction costs. The due to First Nation LP of $245,503 [2021 – $8,386,438] represents the third-party funding removed as an offset to CWIP construction costs.

Details of the relationships with related parties are as follows:

- First Nation LP owns 51% of WPLP.
- Fortis (WP) LP owns 48.99% of WPLP.
- Fortis (WP) LP is owned 80% by Fortis Inc., who in turn owns 100% of FortisOntario Inc.
- Wataynikaneyap Power PM Inc. is owned 100% by FortisOntario Inc.
- Opiikapawiin Services LP is owned 100% by 24 Participating First Nations.

4. Property, plant and equipment

	2022			2021
	Cost $	Accumulated amortization $	Net book value $	Net book value $
Transmission assets				
Land rights	**54,796**	**5,480**	**49,316**	50,686
Station equipment	**129,756,863**	**1,538,474**	**128,218,389**	11,578,819
Towers & fixtures	**255,216,234**	**974,572**	**254,241,662**	—
Poles & fixtures	**23,701,383**	**1,957,334**	**21,744,049**	20,587,372
Overhead conductors & devices	**327,315,817**	**3,511,758**	**323,804,059**	21,057,010
Transportation equipment	**155,392**	**15,539**	**139,853**	—
Construction work-in-progress	**652,326,942**	**—**	**652,326,942**	915,254,096
	1,388,527,427	**8,003,157**	**1,380,524,270**	968,527,983

Included in the cost of property, plant and equipment is $652,326,942 [2021 – $915,254,096] of assets not being amortized because they are under construction.

5. Long-term debt

	2022 $	2021 $
Senior banks [ii]	**630,362,816**	547,800,000
Ontario loan [i]	**319,677,184**	278,000,000
Unamortized financing costs, net of amortization of $8,149,231	**(4,826,303)**	(7,455,557)
	945,213,697	818,344,443

In October 2019, WPLP obtained two non-revolving construction facilities. The details of the facilities are as follows:

[i] The Ontario Financing Authority has provided a facility to a maximum of $1,340,000,000. The rate of interest is dependent upon when the draws are made and is otherwise based on the average three-month Ontario T-Bill rate ["cost of funds"] plus 49.9551 basis points. The cost of funds is accrued and included as a draw on the facility. The balance of the interest rate is payable on a 91-day basis. The average rate of interest for the year is 2.95% [2021 – 0.64%]. The facility is supported by a guarantee of Wataynikaneyap Power GP Inc.

The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

[ii] A $680,000,000 non-revolving construction facility provided by financial institutions and bears interest at the Canadian dollar offered rate plus a spread of 1.5%. The average rate of interest for the year is 4.23% [2021 – 1.96%]. WPLP has provided a performance bond in the amount of $909,989,612 and a pledge of the unitholders' units in support of the facility. The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

6. Deferred contributions

Deferred contributions relate to government funding received for the construction of a new 99km high-voltage, single-circuit, three-phase line to extend from Red Lake to a new substation near Pikangikum First Nation, which serves the community by the construction of an additional 18km of a three-phase 25 kV line. The amount is deferred and amortized at a rate corresponding with the amortization rate of the Pikangikum project assets. The amount amortized in the year was $1,237,590 [2021 – $1,238,745] and is included under Pikangikum capital contribution amortization in the statement of operations.

7. Cash and restricted cash

Bank balances are presented under cash.

8. Financial instruments and risk management

As at December 31, 2022, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $40,311,009 [2021 – $36,215,568].

Risks and uncertainties

WPLP is exposed to risks of varying degrees of significance that could affect its ability to achieve its strategic objectives for growth. The principal financial risks are disclosed below.

Interest rate risk

Interest rate risk is the risk to the Partnership's income that arises from fluctuations in interest rates and the degree of volatility of these rates. The Partnership does not use derivative instruments to reduce its exposure to this risk. The Partnership is exposed to interest rate risk with respect to its long-term debt.

Credit risk

For cash, due from related parties and accounts receivable, WPLP's credit risk is limited to the carrying values on the balance sheet.

Liquidity risk

Liquidity risk to WPLP is minimized. Financing of regulated capital and other expenditures is currently done through funds from its partners and related parties.

One of WPLP's partners, Fortis (WP) LP, is a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

9. Commitments

WPLP's total future minimum lease payments under operating lease commitments over the next five years are as follows:

	$
2023	153,931
2024	160,251
2025	158,892
2026	166,461
2027	152,589
	792,124

In addition, WPLP has contractual commitments to its Engineering, Procurement and Construction contractor due to the impacts of COVID-19. Direct COVID-19 costs that can be reasonably estimated have been accrued as at December 31, 2022, the remaining cost exposure from COVID-19 is not determinable at this time.

10. COVID-19

In March 2020, the World Health Organization declared the COVID-19 outbreak a pandemic. Governments and central banks have responded with monetary and fiscal interventions to stabilize economic conditions.

The extent of such adverse effects on WPLP's business and financial and operational performance are uncertain and difficult to assess. The duration and impact of the COVID-19 pandemic, as well as the effectiveness of government and central bank responses, remain unclear at this time. It is not possible to reliably estimate the duration and severity of these consequences, as well as their impact on the financial position and results of the Partnership for future periods.

ATTACHMENT 2

WPLP Audited Financial Statements for 2021

Wataynikaneyap Power LP

Financial statements

December 31, 2021

Building a better
working world

Independent auditor’s report

To the Directors of
Wataynikaneyap Power LP

Opinion

We have audited the financial statements of **Wataynikaneyap Power LP** (the “Partnership”), which comprise the balance sheet as at December 31, 2021, and statements of income (loss), statement of partners’ deficiency and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2021, and its results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

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 financial statements* section of our report. We are independent of the Partnership in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Partnership'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 the Partnership or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Partnership's financial reporting process.

Auditor’s responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the 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 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 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 the Partnership'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 the Partnership'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 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 the Partnership to cease to continue as a going concern.
- Evaluate the overall presentation, structure, and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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.

Ernst & Young LLP

Toronto, Canada
April 25, 2022

Chartered Professional Accountants
Licensed Public Accountants

Watayníkaneyap Power LP

Balance sheet

As at December 31

	2021	2020
	$	$
Assets		
Cash *[note 7]*	**35,980,389**	9,759,060
Accounts receivable	**227,528**	5,527
Inventory	**384,068**	396,804
HST receivable	**3,322,137**	4,957,221
Due from related parties *[note 3]*	**7,651**	82,657
Total current assets	**39,921,773**	15,201,269
Regulatory assets *[notes 1 and 2]*	**62,740,562**	2,046,966
Property, plant and equipment, net *[note 4]*	**968,527,983**	522,384,140
	1,071,190,318	539,632,375
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**170,637,647**	116,158,333
Due to related parties *[note 3]*	**11,981,756**	1,704,345
Total current liabilities	**182,619,403**	117,862,678
Long-term debt *[note 5]*	**818,344,443**	350,716,664
Deferred contributions *[note 6]*	**53,285,819**	54,556,216
Total liabilities	**1,054,249,665**	523,135,558
Partners' equity	**16,940,653**	16,496,817
	1,071,190,318	539,632,375

See accompanying notes

Approved by the Directors:

J. Scott Hawkes Director

Director

Wataynikaneyap Power LP

Statement of partners' equity

Year ended December 31

	2021				2020
	First Nation LP 51.00%	Fortis (WP) LP 48.99%	Wataynikaneyap Power GP Inc. 0.01%	Total	Total
	$	$	$	$	$
Partners' equity, beginning of year	**9,069,523**	**7,427,666**	**(372)**	**16,496,817**	16,493,364
Net income for the year	**226,356**	**217,435**	**45**	**443,836**	3,453
Partners' equity, end of year	**9,295,879**	**7,645,101**	**(327)**	**16,940,653**	16,496,817

See accompanying notes

Wataynikaneyap Power LP

Statement of income

Year ended December 31

	2021	2020
	$	$
Revenue		
Pikangikum capital contribution amortization	**1,238,745**	1,228,605
Regulatory interest, net	**761,092**	30,387
Interest income	**1,035**	127
	2,000,872	1,259,119
Expenses		
General and administration	**318,291**	27,061
Amortization	**1,238,745**	1,228,605
	1,557,036	1,255,666
Net income for the year	**443,836**	3,453

See accompanying notes

Wataynikaneyap Power LP

Statement of cash flows

Year ended December 31

	2021	2020
	$	$
Operating activities		
Net income (loss) for the year	**443,836**	3,453
Deduct item not affecting cash		
Non-cash regulatory interest	**—**	(24,506)
Amortization of deferred contributions	**1,238,745**	1,228,605
Amortization of property, plant and equipment	**(1,238,745)**	(1,228,605)
Changes in non-cash working capital balances related to operations		
Accounts receivable	**(222,001)**	2,686,056
Inventory	**12,736**	(85,423)
HST receivable	**1,635,084**	(2,306,027)
Due from/to related parties	**10,352,417**	(1,365,003)
Accounts payable and accrued liabilities	**54,479,314**	94,933,982
Cash provided by operating activities	**66,701,386**	93,842,532
Investing activities		
Other assets	**—**	311,196
Regulatory assets	**(60,693,596)**	(705,527)
Purchases of property, plant and equipment	**(447,380,528)**	(365,556,779)
Cash used in investing activities	**(508,074,124)**	(365,951,110)
Financing activities		
Increase (decrease) in deferred contributions	**(33,712)**	397,829
Increase in long-term debt	**467,627,779**	278,537,992
Cash provided by financing activities	**467,594,067**	278,935,821
Net increase in cash during the year	**26,221,329**	6,827,243
Cash, beginning of year	**9,759,060**	2,931,817
Cash, end of year	**35,980,389**	9,759,060

See accompanying notes

Notes to financial statements

December 31, 2021

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP [“WPLP”] was formed and registered under the laws of the Province of Ontario [the “Province”] by First Nation LP, Fortis (WP) LP and Wataynikaneyap Power GP Inc., through a limited partnership agreement dated July 6, 2015. The partnership ownership interests are the following:

First Nation LP – 51.0%
Fortis (WP) LP – 48.99%
Wataynikaneyap Power GP Inc. – 0.01%

Fortis (WP) LP is owned 80% by Fortis Inc. and 20% by Liberty Utilities (Wataynikaneyap Transmission) LP as at December 31, 2020. The shares of First Nation LP are held directly by 24 Participating First Nations in equal shares.

On August 1, 2015, Wataynikaneyap Power Corporation transferred the project assets of the Wataynikaneyap transmission project [the “Project”] to WPLP for $15,759,486, and WPLP assumed notes payable totaling this same amount as consideration for the transfer.

The business of WPLP is the planning and development of the Project, which consists of a new transmission system in northwestern Ontario, to reinforce transmission to Pickle Lake and to connect remote First Nation communities that are currently served by diesel generation. WPLP is a licensed Ontario electricity transmitter and is regulated by the Ontario Energy Board [“OEB”].

The Province identified the Project as a priority in the 2010 and 2013 Long-Term Energy Plans [“LTEP”]. The Province declared in the 2013 LTEP that the connection of remote First Nation communities is a key step towards providing a reliable, clean, and affordable energy future for everyone in the Province. Further declaration of support was provided in the 2017 LTEP; the Project was noted as being selected as the transmitter for connecting remote First Nation communities.

On July 20, 2016, the Lieutenant Governor in Council made an Order in Council pursuant to Section 96.1 of the *Ontario Energy Board Act* [the “Act”] declaring the construction of an electricity line originating at a point between Ignace and Dryden and terminating in Pickle Lake, and the construction of electricity transmission lines extending north from Pickle Lake and Red Lake required to connect certain remote communities, to be a priority project.

On June 2, 2016, the Ontario Legislature passed the *Energy Statute Law Amendment Act, 2015* [also referred to as “Bill 135”]. Bill 135 permitted Cabinet to designate WPLP on July 20, 2016 as the electricity transmitter to connect 16 remote First Nation communities that currently rely on diesel power to the Province’s electricity grid.

The Lieutenant Governor in Council made an Order in Council on July 20, 2016 approving a Directive issued by the Minister of Energy pursuant to Section 28.6.1 of the Act, which required the OEB, without holding a hearing, to amend the conditions of WPLP’s electricity transmission license to include a requirement that WPLP proceed to develop and seek approvals for the Project.

Notes to financial statements

On November 1, 2016, the Minister of Energy issued a letter to WPLP indicating that the Government of Ontario is committed to working with all First Nation communities in Ontario that are diesel-reliant. The Government of Ontario has identified 21 diesel-reliant communities for whom grid connection makes economic sense, of which 16 are included in the Project. WPLP is fully supportive of improving the living conditions for all diesel-reliant First Nation communities by continuing to proceed with the Project to economically expand Ontario's electricity grid. McDowell Lake First Nation is one of the First Nation shareholders and has expressed a desire to become connected to the Project. WPLP will pursue options, as a licensed transmitter, to provide economic means to connect McDowell Lake to the Project and has initiated discussions with the Government of Ontario in this regard.

Basis of accounting

These financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the *CPA Canada Handbook – Accounting*, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada. The financial statements reflect the financial position and results of WPLP. These financial statements do not include the assets, liabilities, revenue and expenses of the partners. No provision has been made in these financial statements for any income taxes which may be assessable to the partners. Further, no provision has been made in the accounts for any salaries or interest accruing to the partners.

Summary of significant accounting policies

Regulation

WPLP is a licensed Ontario electricity transmitter and is regulated by the OEB.

On August 26, 2016, WPLP applied to the OEB for an Accounting Order authorizing WPLP to establish a new regulatory deferral account for the purpose of recording costs in relation to the development of the Project.

On March 23, 2017, the OEB issued its Decision and Order on the deferral account proceeding. The effective date for the new deferral account was established as November 23, 2010. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable Project costs, at regulated interest rates prescribed by the OEB. As a result of the Decision and Order, the OEB has denied all Project costs incurred prior to November 23, 2010, as well as any start-up and partnership formation costs from being included in the deferral account.

On November 22, 2018, the OEB issued its Decision and Order on the deferral account for recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable operation, maintenance and administration costs for the distribution system, as well as any costs that may be incurred after the in-service date which are not paid for by Indigenous Services Canada, at regulated interest rates prescribed by the OEB.

On April 1, 2019, the OEB issued its Decision and Order on the leave to construct application to construct transmission lines and associated facilities in northwestern Ontario. As part of the Decision and Order, the OEB approved the transfer of development costs to WPLP's CWIP account and all future project construction costs are to be recorded in the CWIP account.

Prior to April 1, 2019, costs determined to be Project development costs were deferred as regulatory assets on the balance sheet. All non-Project costs are recognized on the statement of income. Future transmission rate proceedings will determine the proper disposition of all Project costs.

On September 30, 2021, the OEB issued its Decision and Order on the inaugural rate application filed by WPLP for the 2022 test year in April 2021. As part of the Decision and Order, the OEB approved the discontinuance of the CWIP Funding subaccount used to track funding amounts without applying the amounts recorded in that subaccount as offsets to development and construction costs. The OEB further approved the establishment of four new deferral/variance accounts: In Service Date Variance Account, Construction Period Interest Cost Variance Account, Deferred Contingency Deferral Account and the COVID Construction Costs Deferral Account.

Revenue recognition

WPLP's initial transmission rates have not yet been established and development costs for the Project have not been brought before the OEB for disposition. Consequently, WPLP does not currently record any transmission revenue. As noted above, WPLP is allowed regulatory carrying changes on the amount of deferred Project costs and thus recognizes interest income when earned on the balance of such costs.

Expense recoveries are recognized as revenue in the year in which recovery is identified and collectability is assured.

Inventory

Inventory, consisting of material and supplies, is measured at the lower of weighted average cost and net realizable value.

Property, plant and equipment

Property, plant and equipment are initially measured at cost and subsequently measured at cost less accumulated depreciation.

Property, plant and equipment are depreciated over the respective asset's useful life using the following methods and rates:

	Method	Estimated Useful Life
Transmission plant		
Land rights	Straight-line	40 years
Station equipment – transformers and stations	Straight-line	50 years
Station equipment – switches and breakers	Straight-line	40 years
Station equipment – protection and control	Straight-line	20 years
Towers and fixtures	Straight-line	60 years
Poles and fixtures	Straight-line	45 years
Overhead conductors	Straight-line	45 years
General plant		
Office furniture and equipment	Straight-line	10 years
Computer hardware	Straight-line	5 years
Transportation equipment	Straight-line	5-10 years

Income taxes

As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no income taxes are recognized in WPLP's financial statements.

Financial instruments

When WPLP becomes a party to the contractual provisions of a financial instrument, WPLP recognizes the financial asset or financial liability at its fair value except for related party transactions, which are at the carrying or exchange amount depending on the circumstances. WPLP recognizes its transaction costs in income in the period incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their origination, issuance or assumption. Subsequently, WPLP measures its financial instruments at amortized cost. WPLP does not own any equity instruments that would be subsequently measured at fair value if quoted in an active market or at cost less impairment for equity instruments not quoted in an active market. Financial assets measured at amortized cost include cash, accounts receivable and due from related parties.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in income in the period in which they become known. Significant estimates and assumptions that are made by management are used for, but not limited to, the valuation of regulatory assets.

2. Regulatory assets

Regulatory assets arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management project costs.

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in WPLP's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. WPLP continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future transmission rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the OEB at the quarterly approved deferral and variance prescribed interest rate [bankers' acceptances – 3 months plus 0.25 spread]. WPLP currently only accrues interest on regulatory costs that have been netted against third-party funding received. On September 30, 2021, the OEB approved the transfer of COVID-19 costs incurred to December 31, 2020 to a deferral account in the Decision and Order EB-2021-0143. WPLP has recorded all coronavirus disease ["COVID-19"] construction costs in deferral account pending OEB approval.

Long-term regulatory assets consist of the following:

	2021 $	2020 $
Distribution recoverable costs	**3,243,928**	2,046,966
COVID Construction costs deferral account	**59,496,634**	—
Total regulatory assets	**62,740,562**	2,046,966

3. Related party transactions

During the year, WPLP entered into the following transactions with related parties:

	2021 $	2020 $
Project costs paid on behalf of WPLP by		
FortisOntario Inc.	**1,325,445**	2,581,802
Newfoundland Power Inc.	**54,244**	368,165
Opiikapawiin Services LP	**5,238,526**	5,295,818
Wataynikaneyap Power PM Inc.	**3,558,977**	3,108,840
	10,177,192	11,354,625
Project costs recoverable by WPLP from		
Newfoundland Power	**—**	24,280
	—	24,280
Project engagement fees billed to WPLP by First Nation LP	**551,807**	547,791
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**551,807**	547,791

	2021 $	2020 $
Receipts (payments)		
Opiikapawiin Services LP	**(3,392,707)**	(5,526,524)
FortisOntario Inc.	**(1,264,723)**	(2,452,981)
Wataynikaneyap Power PM Inc.	**(4,046,407)**	(3,995,504)
Newfoundland Power Inc.	**(54,244)**	(760,708)
First Nation LP	**(622,786)**	(1,121,226)
Wataynikaneyap Power GP Inc.	**—**	13.
Fortis (WP) GP Inc.	**—**	331.
Fortis (WP) LP	**—**	390.
	(9,380,867)	(13,856,209)

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Notes to financial statements

As at December 31, the amounts due from (to) related parties are as follows:

	2021 $	2020 $
Current due from (to) related parties		
Opiikapawiin Services LP	**(2,680,311)**	(834,493)
First Nation LP	**(93,180)**	(97,233)
First Nation LP (Third Party Funding)	**(8,386,438)**	—
Wataynikaneyap Power PM Inc.	**(589,547)**	(601,060)
FortisOntario Inc.	**(232,280)**	(171,559)
	(11,981,756)	(1,704,345)

	2021 $	2020 $
Current due from related parties		
Wataynikaneyap Power GP Inc.	**2,506**	2,506
Fortis (WP) GP Inc.	**2,340**	2,503
Fortis (WP) LP	**2,805**	3,000
Wataynikaneyap Power PM Inc.	**—**	74,648
	7,651	82,657

The amounts due from related parties are unsecured, non-interest bearing and have no specified terms of repayment.

As part of the OEB Decision and Order EB-2021-0134 on the initial rate application, WPLP was instructed to discontinue the CWIP Funding sub-account without applying the amounts recorded in that subaccount as offsets to development and construction costs. The due to First Nation LP of $8,386,438 represents the third-party funding removed as an offset to CWIP construction costs and will be converted to preferred units in 2022.

Details of the relationships with related parties are as follows:

- First Nation LP owns 51% of WPLP.
- Fortis (WP) LP owns 48.99% of WPLP.
- Fortis (WP) LP is owned 80% by Fortis Inc., who in turn owns 100% of FortisOntario Inc.
- Wataynikaneyap Power PM Inc. is owned 100% by FortisOntario Inc.
- Opiikapawiin Services LP is owned 100% by 24 Participating First Nations.

Notes to financial statements

4. Property, Plant and Equipment

	2021		2020	
	Cost	**Accumulated amortization**	**Net book value**	**Net book value**
	$	$	$	$
Transmission assets				
Land rights	**54,796**	**4,110**	50,686	52,056
Station equipment	**12,317,742**	**738,923**	11,578,819	11,825,177
Poles and fixtures	**22,057,899**	**1,470,527**	20,587,372	21,109,762
Overhead conductors and devices	**22,511,453**	**1,454,443**	21,057,010	21,557,290
Construction work-in-progress	**915,254,096**	**—**	915,254,096	467,839,855
	972,195,986	**3,668,003**	968,527,983	522,384,140

Included in the cost of property, plant and equipment is $915,254,096 [2020 – $467,839,855] of assets not being amortized because they are under construction. Within the balance of construction work-in-progress is $nil [2020 – $17,399,652] of COVID-19 incremental costs incurred due to the pandemic. Subsequent to 2020, all COVID-19 costs have been reclassed to the COVID deferral account for the purposes of recovery in accordance with the OEB Decision & Order EB-2021-0134.

5. Long-term debt

	2021	**2020**
	$	$
Senior banks [ii]	**547,800,000**	240,000,000
Ontario loan [i]	**278,000,000**	121,900,000
Unamortized financing costs, net of amortization of $8,149,231	**(7,455,557)**	(11,183,336)
	818,344,443	350,716,664

In October 2019, WPLP obtained two non-revolving construction facilities. The details of the facilities are as follows:

[i] The Ontario Financing Authority has provided a facility to a maximum of $1,340,000,000. The rate of interest is dependent upon when the draws are made and is otherwise based on the average three month Ontario T-Bill rate ["cost of funds"] plus 49.9551 basis point. The cost of funds is accrued and included as a draw on the facility. The balance of the interest rate is payable on a 91-day basis. The average rate of interest for the year is 0.64% [2020 – 1.02%]. The facility is supported by a guarantee of Wataynikaneyap Power GP Inc. The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

[ii] A $680,000,000 non-revolving construction facility provided by financial institutions and bears interest at the CDOR rate plus a spread of 1.5%. The average rate of interest for the year is 1.96% [2020 – 2.37%]. WPLP has provided a performance bond in the amount of $909,989,612 and a pledge of the unitholders' units in support of the facility. The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

6. Deferred contributions

Deferred contributions relate to government funding received for the construction of new 99km High Voltage, single-circuit, three-phase line to extend from Red Lake to a new substation near Pikangikum First Nation, which serves the community by the construction of an additional 18km of a three-phase 25 kV line. The amount is deferred and amortized at a rate corresponding with the amortization rate of the Pikangikum project assets. The amount amortized in the year was $1,238,745 [2020 – 1,228,605] and is included under Pikangikum capital contribution amortization in the statement of income.

7. Cash

Bank balances are presented under cash.

8. Financial instruments and risk management

As at December 31, 2021, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $36,215,568 [2020 – $9,847,244].

Risks and uncertainties

WPLP is exposed to risks of varying degrees of significance that could affect its ability to achieve its strategic objectives for growth. The principal financial risks are disclosed below.

Interest rate risk

Interest rate risk is the risk to the Partnership's income that arises from fluctuations in interest rates and the degree of volatility of these rates. The Partnership does not use derivative instruments to reduce its exposure to this risk. The Partnership is exposed to interest rate risk with respect to its long-term debt.

Credit risk

For cash, due from related parties and accounts receivable, WPLP’s credit risk is limited to the carrying values on the balance sheet.

Liquidity risk

Liquidity risk to WPLP is minimized. Financing of regulated capital and other expenditures is currently done through funds from its partners and related parties.

One of WPLP’s partners, Fortis (WP) LP, is a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Operating lease commitments

WPLP's total future minimum lease payments under operating lease commitments over the next five years are as follows:

	$
2022	**141,092**
2023	**153,931**
2024	**160,251**
2025	**158,892**
2026	**166,461**
	780,627

9. COVID 19

In March 2020, the World Health Organization declared the spread of COVID-19 outbreak as a pandemic. As a result of this, on March 23, 2020, the Government of Ontario ordered the closure of all non-essential businesses effective March 24, 2020. In addition, the Canadian government imposed travel restrictions to Canada until further notice. These restrictions impacted the operations of WPLP and resulted in the closure of physical premises of the organization. Global stock markets have also experienced great volatility and a significant weakening. Governments and central banks have responded with monetary and fiscal interventions to stabilize economic conditions.

The extent of such adverse effects on WPLP's business and financial and operational performance are uncertain and difficult to assess. The financial impacts will depend on future developments, including the duration, spread and severity of the outbreak; physical distancing requirements; the duration and geographic scope of related travel advisories and restrictions; and the extent of disruptions to businesses globally and their related impact to the economy.

The duration and impact of the COVID-19 pandemic, as well as the effectiveness of Government and central bank responses, remains unclear at this time. It is not possible to reliably estimate the duration and severity of these consequences, as well as their impact on the financial position and results of the Partnership for future periods.

ATTACHMENT 3

WPLP Tax Returns for 2022

Agence du revenu du Canada
Canada Revenue Agency

T5013
Financial
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Partnership Financial Return

055 **For internal use only**

Complete this financial return using the instructions in the T4068, Guide for the Partnership Information Return (T5013 Forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at **canada.ca/my-cra-business-account** or, for authorized representatives, in Represent a Client at **canada.ca/taxes-representatives**.

Unless otherwise stated, all legislative references are to the Income Tax Act or, where appropriate, the Income Tax Regulations.

Identification

Partnership account number
001 78830 4327 RZ0001

Partnership name
006 Wataynikaneyap Power LP
007

Partnership operating or trading name
008
009

Location of the partnership head office
Has this location changed since the last time you filed a partnership information return? . . . . **010** ☐ Yes ☒ No
If you answered **Yes** to line 010, enter the address of the new location on lines 011 to 018.
011
012
015 City
016 Province/State
017 Country
018 Postal or zip code

Mailing address of the partnership
(if different from the head office address)
Has this address changed since the last time you filed a partnership information return? . . . . **020** ☐ Yes ☒ No
If you answered **Yes** to line 020, enter the new mailing address on lines 021 to 028.
021 c/o
023
024
025 City
026 Province/State
027 Country
028 Postal or zip code

Location of the partnership's books and records
(if different from the head office address)
Has this location changed since the last time you filed a partnership information return? . . . . **030** ☐ Yes ☒ No
If you answered **Yes** to line 030, enter the address of the new location on lines 031 to 038.
031
032
035 City
036 Province/State
037 Country
038 Postal or zip code

Is this an amended return? . . . . **040** ☐ Yes ☒ No

Fiscal period to which this information return applies
060 Fiscal period start (Year Month Day) From 2022-01-01
061 Fiscal period-end* (Year Month Day) To 2022-12-31
*If you answered **Yes** to question 078 below, enter the date when the partnership ceased to exist.

The end members of this partnership are
(tick the applicable boxes)
062
01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? . . . . **070** ☐ Yes ☒ No

If you answered **Yes** to line 070, enter the date the partnership was created . . . . **071** Year Month Day

Number of T5013 slips **073** 3

Is this the partnership's final information return up to dissolution? . . . . **078** ☐ Yes ☒ No

If an election was made under section 261 by one or more partners, enter the functional currency code used for this return **079**

Was the partnership a Canadian partnership throughout the fiscal period? . . . . **082** ☒ Yes ☐ No

Type of partnership at the end of the fiscal period

086

Non tax shelter	**Tax shelter**
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number **087**

Industry code (NAICS): 237130

Canada

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Required documents to attach to this T5013 FIN, Partnership Financial Return

- Form T5013 SUM, Summary of Partnership Income
- a copy of each T5013, Statement of Partnership Income, slip issued to partners and nominees or agents
- T5013 SCH 1, Net Income (Loss) for Income Tax Purposes **
  ** If you are an inactive partnership, see line 280 in Guide T4068 for more information.
- T5013 SCH 50, Partner's Ownership and Account Activity

The General Index of Financial Information (GIFI) schedules

- T5013 SCH 100, Balance Sheet Information
- T5013 SCH 125, Income Statement Information
- T5013 SCH 140, Summary Statement (when more than one schedule 125 is filed)
- T5013 SCH 141, Financial Statement Notes Checklist, (not required for investment clubs)

Answer the following questions. For each **affirmative** answer, **attach** the related schedule or form to the partnership return, unless otherwise instructed.

At any time during the fiscal period, was the partnership a member of another partnership (directly or indirectly through one or more partnerships)?	**150**	☐ Yes	☒ No	T5013 SCH 9
Has the partnership had any transactions, including sections 97 and 98 transactions or subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? (Do not include non-arm's length transactions with non-residents.)	**162**	☒ Yes	☐ No	T2058, T2059 or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐ Yes	☒ No	T106
Does the partnership have to file Form T1134 in respect of any foreign affiliates in the fiscal period?	**172**	☐ Yes	☒ No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property or federal, provincial, territorial or municipal political contributions?	**202**	☐ Yes	☒ No	T5013 SCH 2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☐ Yes	☒ No	T5013 SCH 5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ Yes	☒ No	T5013 SCH 6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ Yes	☐ No	T5013 SCH 8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	**212**	☐ Yes	☒ No	T5013 SCH 12
Is the partnership allocating any investment tax credits (ITCs)? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	**231**	☐ Yes	☒ No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	**232**	☐ Yes	☒ No	T661
Did the partnership allocate renounced resource expenses to its members?	**252**	☐ Yes	☒ No	T5013 SCH 52
Did the partnership own or hold specified foreign property for which the total cost amount, at any time in the fiscal period, was more than CAN $100,000?	**259**	☐ Yes	☒ No	T1135
Is the partnership allocating any Canadian journalism labour tax credits?	**260**	☐ Yes	☒ No	T5013 SCH 58
Is the partnership allocating any return of fuel charge proceeds to farmers tax credits?	**261**	☐ Oui	☒ Non	T5013 SCH 63
Is the partnership allocating any air quality improvement tax credits?	**262**	☐ Oui	☒ Non	T5013 SCH 65

Additional information

Did the partnership use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	☐ Yes	☒ No
Was a slip issued to one or more nominees or agents?	**271**	☐ Yes	☒ No
Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2?	**272**	☐ Yes	☒ No
Does the partnership have one or more new nominees or agents?	**273**	☐ Yes	☒ No
Did the partnership allocate any amount of income tax deducted at source?	**274**	☐ Yes	☒ No
Did the partnership make any other election(s) under the Act during the fiscal period?	**275**	☒ Yes	☐ No
If **Yes**, attach a copy of each election form to this return.			
Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed?	**277**	☐ Yes	☒ No
If you answered **Yes** to line 277, provide the business number(s) of the predecessor partnership(s)	**278**		
	279		
Was the partnership inactive throughout the fiscal period this information return applies to?	**280**	☐ Yes	☒ No
If **Yes**, see Guide T4068 to verify your filing requirements.			
Did members of the partnership immigrate to Canada during the fiscal period?	**291**	☐ Yes	☒ No
Did members of the partnership emigrate from Canada during the fiscal period?	**292**	☐ Yes	☒ No
If the major business activity is construction, did you have any subcontractors during the fiscal period?	**295**	☐ Yes	☒ No
Did the partnership report its farming or fishing income using the cash method?	**296**	☐ Yes	☒ No
Is this a publicly traded partnership?	**297**	☐ Yes	☒ No
If you answered **Yes** to line 297, did the partnership issue T5008 information slips to report transactions of interests in the partnership?	**298**	☐ Yes	☐ No

Miscellaneous information

For tax deductions withheld at the source, was an NR4 information return filed for the fiscal period?	**301**	☐ Yes	☒ No
If you answered **Yes** to line 301, enter the non-resident account number	**302**		
If you answered **Yes** to line 301, were NR4 slips issued?	**303**	☐ Yes	☐ No
Is this partnership a specified investment flow-through (SIFT) partnership?	**304**	☐ Yes	☒ No
If you answered **Yes** to line 304, enter the taxable non-portfolio earnings for the fiscal period	**305**		
If you answered **Yes** to line 304, enter the tax payable under Part IX.1 for the fiscal period	**306**		
Enter the amount of the late-filing penalty from line 307 of Schedule 52	**307**		
Amount of payment enclosed with this return	**308**		

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Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15) of the Act

400 ______ Name of designated partner

402 ______ Identification number

Additional information for tax shelters only

Principal promoter

500 ______ Last name (print)

501 ______ First name (print)

502 ______ Identification number

Certification

950 I, King — Last name (print)

951 Glen — First name (print)

954 CFO — Position or title

certify that the information given on this information return and in any attached document is correct and complete. I also certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as noted in a statement attached to this return.

955 2023-05-31 — Year Month Day

______ Signature of the authorized partner

956 (905) 994-3643 — Telephone number

Language of correspondence

Indicate your language of correspondence . . . . **990** ☒ English ☐ French

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Canada Revenue Agency Agence du revenu du Canada

T5013
SCHEDULE 100

PARTNERSHIP'S BALANCE SHEET INFORMATION

Partnership name	Partnership account Number	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31	Original ☒ Amended ☐

Is this a NIL schedule? . . . . 999 Yes ☐ No ☒

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	46,584,306.00	39,921,773.00
	Total tangible capital assets	2008	+	1,388,472,631.00	972,141,190.00
	Total accumulated amortization of tangible capital assets	2009	–	7,997,677.00	3,663,893.00
	Total intangible capital assets	2178	+	54,796.00	54,796.00
	Total accumulated amortization of intangible capital assets	2179	–	5,480.00	4,110.00
	Total long-term assets	2589	+	88,981,445.00	62,740,562.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	1,516,090,021.00	1,071,190,318.00
Liabilities					
	Total current liabilities	3139	+	220,270,000.00	182,619,403.00
	Total long-term liabilities	3450	+	1,012,379,785.00	871,630,262.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	1,232,649,785.00	1,054,249,665.00
Partner's capital					
	Total partners' capital (mandatory field)	3575	+	283,440,236.00	16,940,653.00
	Total liabilities and partners' capital	3585	=	1,516,090,021.00	1,071,190,318.00

* Generic item

Current Assets

SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI		Current year	Prior year
	Cash and deposits				
	* Cash and deposits	1000		35,045,432.00	35,980,389.00
	Cash and deposits		+	35,045,432.00	35,980,389.00
	Accounts receivable				
	* Accounts receivable	1060		5,248,463.00	227,528.00
	Accounts receivable		+	5,248,463.00	227,528.00
	Inventories				
	* Inventories	1120		4,299,104.00	384,068.00
	Inventories		+	4,299,104.00	384,068.00
	Due from/investment in related parties				
	* Due from/investment in related parties	1400		17,114.00	7,651.00
	Due from/investment in related parties		+	17,114.00	7,651.00
	Other current assets				
	* Other current assets	1480		1,954,155.00	3,322,137.00
	Prepaid expenses	1484		20,038.00	
	Other current assets		+	1,974,193.00	3,322,137.00
	Total current assets	1599	=	46,584,306.00	39,921,773.00

* Generic item

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
	Machinery, equipment, furniture and fixtures				
	* Machinery, equipment, furniture, and fixtures	1740	+ 735,990,297.00		56,887,094.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741		– 7,982,138.00	3,663,893.00
	Transportation equipment	1783	+ 155,392.00		
	Accumulated amortization of transportation equipment	1784		– 15,539.00	
	Total		736,145,689.00	7,997,677.00	
	Other tangible capital assets				
	Other capital assets under construction	1920	+ 652,326,942.00		915,254,096.00
	Total		652,326,942.00		
	Total tangible capital assets	2008	= 1,388,472,631.00		972,141,190.00
	Total accumulated amortization of tangible capital assets	2009		= 7,997,677.00	3,663,893.00

* Generic item

Attached Schedule with Total

Tangible capital property – GIFI code 1740 – Machinery, equipment, furniture, and fixtures

Title Tangible capital property – GIFI code 1740 – Machinery, equipment, furniture

Explanatory note

Description	Operator (Note)	Amount	
Poles & Fixtures (G1-16)		23,701,383	00
Overhead Conductors & Devices (G1-16)	+	327,315,817	00
Station Equipment (G1-16)	+	129,756,863	00
Towers & Fixtures (G1-16)	+	255,216,234	00
	+		
	Total	735,990,297	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

GIFI code 1741 – Accumulated amortization of machinery, equipment, furniture, and fixtures

Title GIFI code 1741 – Accumulated amortization of machinery, equipment, furnitu

Explanatory note

Description	Operator (Note)	Amount	
Station Equipment		1,538,474	00
Poles & Fixtures	+	1,957,334	00
Overhead Conductors & Devices	+	3,511,758	00
Towers & Fixtures	+	974,572	00
	+		
	Total	7,982,138	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Intangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2178/2179

Account	Description	GIFI		Intangible capital assets		Accumulated amortization	Prior year
	Intangible assets						
	Rights	**2024**	+	54,796.00			54,796.00
	Accumulated amortization of rights	**2025**			–	5,480.00	4,110.00
	Total			54,796.00		5,480.00	
	Total intangible capital assets	**2178**	=	54,796.00			54,796.00
	Total accumulated amortization of intangible capital assets	**2179**			=	5,480.00	4,110.00

* Generic item

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
	Other long-term assets				
*	Other long-term assets	2420		88,981,445.00	62,740,562.00
	Other long-term assets		+	88,981,445.00	62,740,562.00
	Total long-term assets	2589	=	88,981,445.00	62,740,562.00

* Generic item

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
	Amounts payable and accrued liabilities				
	* Amounts payable and accrued liabilities	2620		216,444,170.00	170,637,647.00
	Amounts payable and accrued liabilities		+	216,444,170.00	170,637,647.00
	Due to related parties				
	* Due to related parties	2860		3,825,830.00	11,981,756.00
	Due to related parties		+	3,825,830.00	11,981,756.00
	Total current liabilities	3139	=	220,270,000.00	182,619,403.00

* Generic item

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
	Long-term debt				
	* Long-term debt	3140		945,213,697.00	818,344,443.00
	Long-term debt		+	945,213,697.00	818,344,443.00
	Other long-term liabilities				
	* Other long-term liabilities	3320		67,166,088.00	53,285,819.00
	Other long-term liabilities		+	67,166,088.00	53,285,819.00
	Total long-term liabilities	3450	=	1,012,379,785.00	871,630,262.00

* Generic item

Attached Schedule with Total

GIFI code 3140 – Long-term debt

Title GIFI code 3140 – Long-term debt

Explanatory note

Description	Operator (Note)	Amount	
Senior Banks (G1-16)		630,362,816	00
Ontario Loan (G1-16)	+	319,677,184	00
Unamortized financing cost	+	-4,826,303	00
	+		
	Total	945,213,697	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

GIFI code 3320 – Other long-term liabilities

Title GIFI code 3320 – Other long-term liabilities

Explanatory note

Description	Operator (Note)	Amount	
Regulatory liabilities (G1-4)		15,195,242	00
Deferred contributions (G1-4)	+	51,970,846	00
	+		
	Total	67,166,088	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Partner's capital

SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI		Current year	Prior year
Total net income/loss					
	Net income/loss	3545	+	12,363,145.00	443,836.00
	Total net income/loss	3550	=	12,363,145.00	443,836.00
General partners' capital					
	General partners' capital beginning balance	3551	+	-327.00	-372.00
	General partners' net income (loss)	3552	+	1,236.00	45.00
	General partners' contributions during the fiscal period	3554	+	484.00	
	General partners' capital ending balance	3560	=	1,393.00	-327.00
Limited partners' capital					
	Limited partners' capital beginning balance	3561	+	16,940,980.00	16,497,189.00
	Limited partners' net income (loss)	3562	+	12,361,909.00	443,791.00
	Limited partners' contributions during the fiscal period	3564	+	254,135,954.00	
	Limited partners' capital ending balance	3571	+	283,438,843.00	16,940,980.00
	Total partners' capital	3575	=	283,440,236.00	16,940,653.00

***** Generic item

Attached Schedule with Total

GIFI code 3561 – Limited partners' capital beginning balance

Title GIFI code 3561 – Limited partners' capital beginning balance

Explanatory note

Description	Operator (Note)	Amount	
First Nations LP (G1-5)		9,295,879	00
Fortis (WP) LP (G1-5)	+	7,645,101	00
	+		
	Total	16,940,980	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

GIFI code 3564 – Limited partners' contributions during the fiscal period

Title GIFI code 3564 – Limited partners' contributions during the fiscal period

Explanatory note

Description	Operator (Note)	Amount	
First Nation LP		129,374,545	00
Fortis LP	+	124,761,893	00
Cancellation of Units	+	4,848,570	00
Contributed Surplus	+	-4,849,054	00
	+		
	Total	254,135,954	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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T5013
SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31	Original ☒ Amended ☐

Income statement information

Description **GIFI**

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Operating name **0001**

Description of the operation **0002**

Sequence Number **0003** 01

Income statement information

Account	Description	GIFI	Current year	Prior year
	Total sales of goods and services	8089 +	25,071,060.00	
	Cost of sales	8518 –		
	Gross profit/loss	8519 =	25,071,060.00	
	Cost of sales	8518 +		
	Total operating expenses	9367 +	15,125,598.00	1,557,036.00
	Total expenses (mandatory field)	9368 =	15,125,598.00	1,557,036.00
	Total revenue (mandatory field)	8299 +	27,488,743.00	2,000,872.00
	Total expenses (mandatory field)	9368 –	15,125,598.00	1,557,036.00
	Net non-farming income	9369 =	12,363,145.00	443,836.00

Farming income statement information

Account	Description	GIFI	Current year	Prior year
	Total farm revenue (mandatory field)	9659 +		
	Total farm expenses (mandatory field)	9898 –		
	Net farm income	9899 =		

Account	Description	GIFI	Current year	Prior year
	Net income/loss before extraordinary items – all operations	9970 =	12,363,145.00	443,836.00

Account	Description	GIFI	Current year	Prior year
	Total other comprehensive income	9998 =		

Extraordinary items and income (linked to Schedule 140)

Account	Description	GIFI	Current year	Prior year
	Extraordinary item(s)	9975 –		
	Legal settlements	9976 –		
	Unrealized gains/losses	9980 +		
	Unusual items	9985 –		
	Current income taxes	9990 –		
	Deferred income tax provision	9995 –		
	Total – Other comprehensive income	9998 +		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	12,363,145.00	443,836.00

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	25,071,060.00	
	Total sales of goods and services	8089	=	25,071,060.00	
	Investment revenue				
	* Investment revenue	8090		1,126,160.00	761,092.00
	Interest from other Canadian sources	8094		53,933.00	1,035.00
	Investment revenue		+	1,180,093.00	762,127.00
	Other revenue				
	* Other revenue	8230		1,237,590.00	1,238,745.00
	Other revenue		+	1,237,590.00	1,238,745.00
	Total revenue	8299	=	27,488,743.00	2,000,872.00

***** Generic item

Attached Schedule with Total

GIFI code 8094 – Amount – Interest from other Canadian sources

Title GIFI code 8094 – Amount – Interest from other Canadian sources

Explanatory note

Description	Operator (Note)	Amount	
Interest Income		53,933	00
	+		
	+		
	Total	53,933	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	Advertising and promotion				
	Meals and entertainment	8523		29,529.00	
	Advertising and promotion		+	29,529.00	
	* Amortization of tangible assets	8670	+	4,342,053.00	1,238,745.00
	Interest and bank charges				
	* Interest and bank charges	8710		4,939,252.00	
	Interest and bank charges		+	4,939,252.00	
	Office expenses				
	* Office expenses	8810		1,318,308.00	
	Office expenses		+	1,318,308.00	
	Other expenses				
	* Other expenses	9270		1,887,789.00	
	General and administrative expenses	9284		2,608,667.00	318,291.00
	Other expenses		+	4,496,456.00	318,291.00
	Total operating expenses	9367	=	15,125,598.00	1,557,036.00

* Generic item

Attached Schedule with Total

GIFI code 9284 – Amount – General and administrative expenses

Title GIFI code 9284 – Amount – General and administrative expenses

Explanatory note

Description	Operator (Note)	Amount	
G&S (G1-6)		2,638,196	00
Less M&E claimed	+	-29,529	00
	+		
	Total	2,608,667	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Financial Statement Notes Checklist

Protected B when completed

T5013
Schedule 141

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31	☒ Original ☐ Amended

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements
- For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 forms), and Guide RC4088, General Index of Financial Information (GIFI)
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, Partnership Financial Return

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? **095** ☒ Yes ☐ No

Is the accountant connected with the partnership? * **097** ☐ Yes ☒ No

Note: If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.

* A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the accountant's highest level of involvement: **198**

Completed an auditor's report ☒ 1

Completed a review engagement report ☐ 2

Conducted a compilation engagement ☐ 3

Part 3 – Reservations

If you selected option 1 or option 2 **in part 2** above, answer the following question:

Has the accountant expressed a reservation? **099** ☐ Yes ☒ No

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: **110**

Prepared the information return (financial statements prepared by client) ☒ 1

Prepared the information return and the financial information contained therein (financial statements have not been prepared) ☐ 2

Were notes to the financial statements prepared? **101** ☒ Yes ☐ No

If **yes**, answer the following four questions:

Are subsequent events mentioned in the notes? **104** ☐ Yes ☒ No

Is re-evaluation of asset information mentioned in the notes? **105** ☐ Yes ☒ No

Is contingent liability information mentioned in the notes? **106** ☐ Yes ☒ No

Is information regarding commitments mentioned in the notes? **107** ☒ Yes ☐ No

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below. **108** ☐ Yes ☒ No

Are you filing joint venture(s) financial statements? **109** ☐ Yes ☐ No

Approval code: RC-22-P010

Canada

Partnership account number	Fiscal period-end Year Month Day
78830 4327 RZ0001	2022-12-31

Protected B when completed

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? **200** ☐ Yes ☒ No

If **yes**, enter the amount recognized:

In net income Increase (decrease)

Property, plant and equipment **210** ______

Intangible assets **215** ______

Investment property **220** ______

Biological assets **225** ______

Financial instruments **230** ______

Other **235** ______

In other comprehensive income Increase (decrease)

Property, plant, and equipment **211** ______

Intangible assets **216** ______

Financial instruments **231** ______

Other **236** ______

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? **250** ☐ Yes ☒ No

Did the partnership apply hedge accounting during the fiscal period? **255** ☐ Yes ☒ No

Did the partnership discontinue hedge accounting during the fiscal period? **260** ☐ Yes ☒ No

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? **265** ☐ Yes ☒ No

If **yes**, you have to maintain a separate reconciliation.

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31

Is this a NIL schedule? . . . . **999** Yes ☐ No ☒

Assets – lines 1000 to 2599

1000	35,045,432.00	**1060**	5,248,463.00	**1120**	4,299,104.00
1400	17,114.00	**1480**	1,954,155.00	**1484**	20,038.00
1599	46,584,306.00	**1740**	735,990,297.00	**1741**	-7,982,138.00
1783	155,392.00	**1784**	-15,539.00	**1920**	652,326,942.00
2008	1,388,472,631.00	**2009**	-7,997,677.00	**2024**	54,796.00
2025	-5,480.00	**2178**	54,796.00	**2179**	-5,480.00
2420	88,981,445.00	**2589**	88,981,445.00	**2599**	1,516,090,021.00

Liabilities – lines 2600 to 3499

2620	216,444,170.00	**2860**	3,825,830.00	**3139**	220,270,000.00
3140	945,213,697.00	**3320**	67,166,088.00	**3450**	1,012,379,785.00
3499	1,232,649,785.00				

Partner's capital – lines 3540 to 3575

3545	12,363,145.00	**3550**	12,363,145.00	**3551**	-327.00
3552	1,236.00	**3554**	484.00	**3560**	1,393.00
3561	16,940,980.00	**3562**	12,361,909.00	**3564**	254,135,954.00
3571	283,438,843.00	**3575**	283,440,236.00	**3585**	1,516,090,021.00

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	25,071,060.00	**8089**	25,071,060.00	**8090**	1,126,160.00
8094	53,933.00	**8230**	1,237,590.00	**8299**	27,488,743.00

Cost of sales – lines 8300 to 8519

8519	25,071,060.00

Operating expenses – lines 8520 to 9369

8523	29,529.00	**8670**	4,342,053.00	**8710**	4,939,252.00
8810	1,318,308.00	**9270**	1,887,789.00	**9284**	2,608,667.00
9367	15,125,598.00	**9368**	15,125,598.00	**9369**	12,363,145.00

Farming revenue – lines 9370 to 9659

9659	0.00

Farming expenses – lines 9660 to 9899

9898	0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	12,363,145.00	**9999**	12,363,145.00

Approval code: RC-22-P010

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Protected B when completed

T5013
Schedule 1

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Is this a NIL schedule? **999** ☐ Yes ☒ No

(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140 **500** 12,363,145.00

Add:

Provision for Part IX.1 specified investment flow through (SIFT) taxes	101			
Amortization/depreciation of tangible assets	104	4,342,053.00		
Amortization of natural resource assets	105			
Amortization of intangible assets	106			
Recapture of capital cost allowance from Schedule 8	107			
Income or loss for tax purposes from partnerships	109			
Loss in equity of affiliates	110			
Loss on disposal of assets per financial statements	111			
Charitable donations and gifts from Schedule 2	112			
Political contributions from Schedule 2	114			
Current fiscal period's holdbacks	115			
Deferred and prepaid expenses	116			
Depreciation in inventory – end of fiscal period	117			
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	118			
Capitalized interest and property taxes on vacant land	119			
Non-deductible club dues and fees	120			
Non-deductible meals and entertainment expenses	121	14,765.00		
Non-deductible automobile expenses	122			
Non-deductible life insurance premiums	123			
Non-deductible company pension plans	124			
Reserves from financial statements – balance at the end of the fiscal period	126			
Soft costs on construction and renovation of buildings	127			
Salaries and wages paid to partners deducted on financial statements	150			
Cost of products available for sale that were consumed	151			
Personal expenses of the partners paid by the partnership	152			
Dividend rental arrangement compensation payment deductions	154			
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	155			
Certain fines and penalties	156			
Amount from line 508 on page 2 of this schedule	199	4,855,953.00		
Total (**Add** lines 101 to 199. Enter this amount on line 501)		9,212,771.00 ▶	501	+ 9,212,771.00
Deduct: Amount from line 511 on page 3 of this schedule			502	– 21,575,916.00
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	=
Deduct: Net income (loss) for general partners			504	–
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	=

Approval code: RC-22-P010

Partnership account number	78830 4327 RZ0001
Fiscal period end Year Month Day	2022-12-31

Protected B when completed

Add:

Accounts payable and accruals for cash basis – closing	201			
Accounts receivable and prepaid for cash basis – opening	202			
Accrual inventory – opening	203			
Accrued dividends – prior fiscal period	204			
Book loss on joint ventures or partnerships	205			
Capital items expensed	206			
Debt issue expense	208			
Deemed dividend income	209			
Deemed interest on loans to non-residents	210			
Deemed interest received	211			
Development expenses claimed in current fiscal period	212			
Dividend stop-loss adjustment	213			
Dividends credited to the investment account	214			
Exploration expenses claimed in current fiscal period	215			
Financing fees deducted in books	216			
Foreign accrual property income	217			
Foreign affiliate property income	218			
Foreign exchange included in retained earnings	219			
Gain on settlement of debt – income inclusion under subsection 80(13)	220			
Interest paid on income debentures	221			
Limited partnership losses	222			
Loss from international banking centres	223			
Mandatory inventory adjustment – included in current fiscal period	224			
Non-deductible advertising	226			
Non-deductible interest	227			
Non-deductible legal and accounting fees	228			
Optional value of inventory – included in current fiscal period	229			
Other expenses from financial statements	230			
Recapture of SR&ED expenditures from Form T661	231			
Resource amounts deducted	232			
Sales tax assessments	234			
Write-down of capital property	236			
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238			
Taxable/Non-deductible other comprehensive income items	239			
Total (**Add** lines 201 to 239. Enter this amount on line 506)			▶ 506	+

Other additions:

600	Asset Retirement	290	6,899.00		
601	Non-deductible Expense	291	4,849,054.00		
602		292			
603		293			
604		294			
	Total (**Add** lines 290 to 294. Enter this amount on line 507)		4,855,953.00	▶ 507	+ 4,855,953.00

Total (**Add** lines 506 and 507) 508 = 4,855,953.00

Enter the amount from line 508 on line 199 on page 1 of this schedule.

Partnership account number	Fiscal period end Year Month Day
78830 4327 RZ0001	2022-12-31

Protected B when completed

Deduct:

Accounts payable and accruals for cash basis – opening	300	
Accounts receivable and prepaid for cash basis – closing	301	
Accrual inventory – closing	302	
Accrued dividends – current fiscal period	303	
Bad debt	304	
Book income of joint venture or partnership	305	
Equity in income from affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment – included in prior fiscal period	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses – broadcasting	311	
Non-Canadian advertising expenses – printed materials	312	
Optional value of inventory – included in prior fiscal period	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payments	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	
Non-taxable/Deductible other comprehensive income items	347	

Other less common deductions:

700	Amortization of deferred contribution	390	1,237,590.00
701	20(1)(e) Financing fees	391	3,120,958.00
702	Gain on Disposal	392	6,899.00
703		393	
704		394	

Total (**Add** lines 300 to 394. Enter this amount on line 509) 4,365,447.00 ▶ **509** + 4,365,447.00

Other deductions:

Gain on disposal of assets per financial statements	401	
Non-taxable dividends under section 83	402	
Capital cost allowance from Schedule 8	403	17,210,469.00
Terminal loss from Schedule 8	404	
Foreign non-business tax deduction under subsection 20(12)	407	
Prior fiscal period's holdbacks	408	
Deferred and prepaid expenses	409	
Depreciation in inventory – end of prior fiscal period	410	
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	
Reserves from financial statements – balance at the beginning of the fiscal period	414	
Patronage dividends	416	
Contributions to deferred income plans	417	

Total (**Add** lines 401 to 417. Enter this amount on line 510) 17,210,469.00 ▶ **510** + 17,210,469.00

Total (**Add** lines 509 and 510) **511** = 21,575,916.00
Enter this amount on line 502 on page 1 of this schedule.

Attached Schedule with Total

Other additions – Amount

Title Other additions – Amount

Explanatory note

Description	Operator (Note)	Amount	
Fortis Nations LP		2,473,018	00
Fortis WP LP	+	2,375,552	00
WP GP Inc.	+	484	00
	-		
	+		
	Total	4,849,054	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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T5013
Schedule 8
Protected B when completed

Capital Cost Allowance (CCA)

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2022-12-31	☒ Original ☐ Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, or to account for acquisitions or dispositions of depreciable property, or both.
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms).
- If you do not have enough space to list all the information, use an additional T5013 Schedule 8.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the fiscal period with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes ☐ No ☐

If you answered **yes**, complete Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your partnership) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 13 in Part 2.

	1 Name of EPOP **110**	2 Identification number See **note 1** **115**	3 Percentage assigned under the agreement **120**
1			%
2			%
3			%
4			%
5			%
6			%
7			%
8			%
		Total	%

Immediate expensing limit allocated to the partnership (see **note 2**) **125**

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: If the total of column 3 is more than 100%, enter 0.

Part 2 – CCA calculation

	1 Class number See **note 3** **200**	2 Undepreciated capital cost (UCC) at the beginning of the fiscal period **201**	3 Cost of acquisitions during the fiscal period (new property must be available for use) See **note 4** **203**	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) See **note 5** **232**	5 Adjustments and transfers (show amounts that will reduce the UCC in brackets) See **note 6** **205**	6 Amount from column 5 that is assistance received or receivable during the fiscal period for a property, subsequent to its disposition See **note 7** **221**	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition See **note 8** **222**	8 Proceeds of dispositions See **note 9** **207**
1	14.1	46,612.95						
2	99	809,574,233.01	416,415,723.00		-573,663,014.01			
3	47	105,667,932.00	573,507,622.01					
4	10		155,392.00					
5								
6								
7								
8								

	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** **236**	12 Income earned from the business or property in which the DIEP is used See **note 12** **237**	13 Immediate expensing See **note 13** **238**	14 Cost of acquisitions on remainder of Class (column 3 **minus** column 4 **plus** column 11 **minus** column 13)	15 Cost of acquisitions from column 14 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 14** **225**	16 Remaining UCC (column 10 **minus** column 13) (if negative, enter "0")	17 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **minus** column 9 **plus** column 6 **minus** column 14 **plus** column 15 **minus** column 7) (if negative, enter "0") See **note 15**
1		46,612.95						46,612.95	
2		652,326,942.00				416,415,723.00	416,415,723.00	652,326,942.00	
3		679,175,554.01				573,507,622.01	573,507,622.01	679,175,554.01	
4		155,392.00				155,392.00	155,392.00	155,392.00	
5									
6									
7									
8									
		Totals							

Protected B when completed

Part 2 – CCA calculation (continued)

	18 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 15 **minus** column 17) (if negative, enter "0")	19 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 18 **multiplied** by the relevant factor) See **note 16**	20 UCC adjustment for property acquired during the fiscal period other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 14 **minus** column 15 **minus** column 6 **plus** column 7 **minus** column 8 **plus** column 9) (if negative, enter "0") See **note 17** **224**	21 CCA rate % See **note 18** **212**	22 Recapture of CCA See **note 19** **213**	23 Terminal loss See **note 20** **215**	24 CCA (for declining balance method, the result of column 16 **plus** column 19 **minus** column 20, **multiplied** by column 21, or a lower amount, **plus** column 13) See **note 21** **217**	25 UCC at the end of the fiscal period (column 10 **minus** column 24) **220**
1				5.00			3,262.91	43,350.04
2	416,415,723.00	208,207,861.50						652,326,942.00
3	573,507,622.01	286,753,811.01		8.00			17,137,279.69	662,038,274.32
4	155,392.00	77,696.00		30.00			69,926.40	85,465.60
5								
6								
7								
8								
				Totals	**230**	**240**	**250** 17,210,469.00	

Enter the total of line 230 on line 107 of Schedule 1.
Enter the total of line 240 on line 404 of Schedule 1.
Enter the total of line 250 on line 403 of Schedule 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous fiscal periods that has now become available for use, net of any assistance received or entitled to be received in the fiscal period from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 5: A DIEP reported in column 4 is a property acquired after December 31, 2021, by a Canadian partnership (all of the members of which were, throughout the period, Canadian-controlled private corporations, individuals (other than trusts) resident in Canada or a combination thereof) that becomes available for use before 2025 (if all the members are individuals throughout the fiscal period), or before 2024 in any other case. The property is designated as such on or before the day that is 12 months after the filing-due date of an information return under section 229 by any member of the partnership for the fiscal period to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the fiscal period in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

Note 6: Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the fiscal period for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the Guide T4068 for other examples of adjustments and transfers to include in column 5.

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Part 2 – CCA calculation (continued)

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 8: Include all amounts you have repaid during the fiscal period for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the fiscal period, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle.

Note 10: If the amount in column 5 (as shown in brackets) reduces the UCC, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 11: The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) are met.

Note 12: The total of column 12 is equal to the net income for tax purposes (before any CCA deductions) of the source of income (business or property) in which the relevant DIEP is used during the fiscal period. If there is more than one source of income, the total of column 12 should be equal to the total income from all sources.

Note 13: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the fiscal period (total of column 13) is limited to the lesser of:

1. Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
   - $1.5 million, if you are not associated with any other EPOP in the fiscal period
   - amount from line 125, if you are associated in the fiscal period with one or more EPOPs
   - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the fiscal period with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
   - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent fiscal periods ending in a calendar year, if you have two or more fiscal periods ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
   - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

   The immediate expensing limit has to be prorated if your fiscal period is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.
2. UCC of the DIEP: total of column 11
3. Income earned from the business or property in which the DIEP is used: total of column 12.

Note 14: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.

See Guide T4068 for more information.

Note 15: Include only elements from columns 6 and 7 that are not related to the DIEP.

Note 16: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use before 2024 are:

- 2 1/3 for property in Classes 43.1, 54, and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 21 for additional information) and
- 0.5 for all other property that is an AIIP

Part 2 – CCA calculation (continued)

Note 17: The UCC adjustment for property acquired during the fiscal period (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP, property included in Classes 54 to 56, and property to which the immediate expensing was applied). Include only elements from columns 6 and 7 that are not related to the DIEP.

For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 18: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 24.

Note 19: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 22 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 20: If no property is left in the class at the end of the fiscal period and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 23. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 21: If the fiscal period is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4068 for more information.

For property in class 10.1 disposed of during the fiscal period, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the fiscal period.

For AIIP listed below, the maximum first fiscal period allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the fiscal period of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot, or cubic metre cut in the fiscal period and the UCC at the end of the fiscal period (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also applies to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

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Partner's Ownership and Account Activity

Protected B when completed

T5013
Schedule 50

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	788304327RZ0001	2022-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	**010**	3
Number of partners who disposed of all, or part of, their partnership interest	**011**	
Number of nominees or agents	**012**	
Total of all amounts from line 220	**015**	

Partner 1

Ownership						Fiscal period's income (loss) allocation	Account activity
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
First Nation LP	722558525RZ0001	3	0	51.0000	☐ Yes ☒ No		10963826.00

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
129,374,545.00	-1,367,121.56		-2,919,059.00				

Partner 2

Ownership						Fiscal period's income (loss) allocation	Account activity
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
Fortis (WP) LP	749436499RZ0001	3	0	48.9900	☐ Yes ☒ No		9247312.00

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
124,761,893.00	-1,313,240.88		-1,929,995.00				

Approval code: RC-22-P010

Protected B when completed

Partner 3	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
Wataynikaneyap Power GP Inc.	815046362RC0001	2	2	0.0100	☐ Yes ☒ No		N/A

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-268.06						

Partner 4	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

List Detailing the Partner's Ownership and Account Activity

Partnership Wataynikaneyap Power LP

Partner	Partner code	Percentage (%) of partner's interest	Line 220	Line 300	Line 320	Line 330	Line 340	Line 350
1 First Nation LP	0	51.0000		10,963,826 00	-1,367,121 56		-2,919,059 00	
2 Fortis (WP) LP	0	48.9900		9,247,312 00	-1,313,240 88		-1,929,995 00	
3 Wataynikaneyap Power GP Inc.	2	0.0100			-268 06			
		Total		20,211,138 00	-2,680,630 50		-4,849,054 00	

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Fiscal period-end
Exercice se terminant le
YYYY-MM-DD
2022-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code – Code de l'associé	**002**	0
Country code – Code du pays	**003**	CAN
Recipient type – Genre de bénéficiaire	**004**	4
Partnership account number (15 characters) – Numéro de compte de la société de personnes (15 caractères)	**001**	788304327RZ0001
Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire	**010**	
Total business income (loss) – Total du revenu (de la perte) d'entreprise	**020**	
Partner's identification number – Numéro d'identification de l'associé	**006**	722558525RZ0001
Partner's share (%) of partnership – Part de l'associé (%) dans la société de personnes	**005**	51.000000
Total capital gains (losses) – Total des gains (pertes) en capital	**030**	
Capital cost allowance – Déduction pour amortissement	**040**	8,777,339 19

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► First Nation LP
300 Anemki Place, Suite C
Fort William First Nation ON P7J 1H9

Box – Case	Code	Amount – Montant	Box – Case	Code	Amount – Montant
105		133,156,013 51	106		133,156,013 51
118		14,019,258 93			

Box – Case	Code	Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le

YYYY-MM-DD
2022-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 0	**003** CAN	**004** 4

Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) Total du revenu (de la perte) d'entreprise
001 788304327RZ0001	**010**	**020**

Partner's identification number Numéro d'identification de l'associé	Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	Total capital gains (losses) Total des gains (pertes) en capital	Capital cost allowance Déduction pour amortissement
006 749436499RZ0001	**005** 48.990000	**030**	**040** 8,431,408 76

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initiales – Initiales

► Fortis (WP) LP

1130 Bertie Street
PO BOX 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
105		127,983,935 65	106		127,983,935 65
118		13,466,735 20			

Box – Case	Code	Other information – Autres renseignements

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T5013 (21) **Protected B** when completed – **Protégé B** une fois rempli

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le
YYYY-MM-DD
2022-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 2	**003** CAN	**004** 3

Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) Total du revenu (de la perte) d'entreprise
001 788304327RZ0001	**010**	**020**

Partner's identification number Numéro d'identification de l'associé	Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	Total capital gains (losses) Total des gains (pertes) en capital	Capital cost allowance Déduction pour amortissement
006 815046362RC0001	**005** 0.010000	**030**	**040** 1,721 05

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initiales – Initiales

► Wataynikaneyap Power GP Inc.

1130 Bertie Street
P.O. Box 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		2,748 87			

Box – Case	Code	Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

T5013 (21) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency / Agence du revenu du Canada

Protected B when completed

Summary of Partnership Income

T5013 Summary

Fill out this summary and the related slips using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 Forms).

The **partnership information return** is made up of three parts:

- T5013 FIN, Partnership Financial Return
- All the T5013 schedules the partnership has to file, depending on its fiscal situation
- T5013, Statement of Partnership Income, slips and this summary

If you make certain payments to a non-resident of Canada, the amounts must be reported on an NR4 return. For more information, see Guide T4061, NR4 – Non-Resident Tax Withholding, Remitting and Reporting.

For more information on filing the partnership information return, go to **canada.ca/t5013-filing-requirements**.

Do not use this area.

50 1616

Part 1 – Identification

Partnership's account number: 78830 4327 RZ0001

Fiscal period-start (Year Month Day): 2022-01-01

Fiscal period-end (Year Month Day): 2022-12-31

Name of the partnership: Wataynikaneyap Power LP

Postal or ZIP code: L2A 5Y2

Are you a nominee or an agent? (If yes, provide the following information) ☐ Yes ☐ No

Nominee or agent's account number:

Name of the nominee or agent:

Postal or ZIP code:

Is the partnership a tax shelter? ☐ Yes ☒ No

If yes, enter the tax shelter identification number (TS):

Part 2 – Totals from T5013 slips

Total number of T5013 information slips attached	009	3
Total limited partner's business income (loss)	010	
Total business income (loss)	020	
Total capital gains (losses)	030	
Capital cost allowance	040	17,210,469.00

Fill out the six boxes below using the information found on the T5013 slips

Canadian and foreign net rental income (loss)	110	
Professional income (loss)	120	
Renounced Canadian exploration expenses	190	
Renounced Canadian development expenses	191	
Expenses qualifying for an ITC *	194	
Total carrying charges	210	

* Line 194 is the total of all the amounts in boxes 194 and 239 of all the T5013 slips.

Part 3 – Contact information

076 Person to contact about this summary: Ernst & Young LLP

078 Telephone number: (416) 864-1234

Part 4 – Certification

I certify that the information given in this summary and the related slips is correct and complete.

Year Month Day: 2023-05-31

Signature of authorized person:

Position or office: CFO

Prepared by: Ernst & Young LLP

Year Month Day: 2023-05-31

Part 5 – Privacy notice

Personal information is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

ATTACHMENT 4

WPLP Tax Returns for 2021

Canada Revenue Agency / Agence du revenu du Canada

Protected B when completed

Partnership Financial Return

T5013 Financial

055 **For internal use only**

Complete this financial return using the instructions in guide T4068, Guide for the Partnership Information Return (T5013 Forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at **canada.ca/my-cra-business-account** or, for authorized representatives, in Represent a Client at **canada.ca/taxes-representatives**.

Note: All legislative references on this form refer to the Income Tax Act.

Identification

Partnership account number:
001 78830 4327 RZ0001

Partnership name:
006 Wataynikaneyap Power LP
007

Partnership operating or trading name:
008
009

Location of the partnership head office:
Has this location changed since the last time you filed a partnership information return? **010** ☐ Yes ☒ No
If you answered **Yes** to line 010, enter the address of the new location on lines 011 to 018:
011
012
City **015**
Province/State **016**
Country **017**
Postal or zip code **018**

Mailing address of the partnership:
(if different from the head office address)
Has this address changed since the last time you filed a partnership information return? **020** ☐ Yes ☒ No
If you answered **Yes** to line 020, enter the new mailing address on lines 021 to 028:
021 c/o
023
024
City **025**
Province/State **026**
Country **027**
Postal or zip code **028**

Location of the partnership's books and records:
(if different from the head office address)
Has this location changed since the last time you filed a partnership information return? **030** ☐ Yes ☒ No
If you answered **Yes** to line 030, enter the address of the new location on lines 031 to 038:
031
032
City **035**
Province/State **036**
Country **037**
Postal or zip code **038**

Is this an amended return? **040** ☐ Yes ☒ No

Fiscal period to which this information return applies:
060 Fiscal period start (Year Month Day) From 2021-01-01
061 Fiscal period-end* (Year Month Day) To 2021-12-31
*If you answered **Yes** to question 078 below, enter the date when the partnership ceased to exist.

The end members of this partnership are (tick the applicable boxes):
062 01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? **070** ☐ Yes ☒ No
If you answered **Yes** to line 070, enter the date the partnership was created: (Year Month Day) **071**

Number of T5013 slips: **073** 3

Is this the partnership's final information return up to dissolution? **078** ☐ Yes ☒ No

If an election was made under section 261 by one or more partners, enter the functional currency code used for this return: **079**

Was the partnership a Canadian partnership throughout the fiscal period? **082** ☒ Yes ☐ No

Type of partnership at the end of the fiscal period:
086

Non tax shelter	**Tax shelter**
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number: **087**

Industry code (NAICS): **098** 237130

Approval code: RC-21-P010

Canada

Protected B when completed

Partnership account number:
001 78830 4327 RZ0001

Fiscal period end
Year Month Day
061 2021-12-31

Required documents to attach to this T5013 FIN, Partnership Financial Return

1. Form T5013 SUM, Summary of Partnership Income, and a copy of each T5013, Statement of Partnership Income, issued to partners and nominees or agents
2. The General Index of Financial Information (GIFI) schedules; T5013SCH100, Balance Sheet Information; T5013SCH125, Income Statement Information; T5013SCH140, Summary Statement (when more than one schedule 125 is filed); and T5013SCH141, Financial Statement Notes Checklist, (not required for investment clubs)
3. Schedules: T5013SCH1, Net Income (Loss) for Income Tax Purposes; (If you are an inactive partnership, see line 280 in Guide T4068 for more information); and T5013SCH50, Partner's Ownership and Account Activity
4. For each **Yes** answer to the following questions, **attach** the related schedule or form to the partnership return, unless otherwise instructed

				Schedule or form
At any time during the fiscal period, was the partnership a member of another partnership (directly or indirectly through one or more partnerships)?	**150**	☐ Yes	☒ No	9
Has the partnership had any transactions, including sections 97 and 98 transactions or subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? (Do not include non-arm's length transactions with non-residents.)	**162**	☐ Yes	☒ No	T2058, T2059, or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐ Yes	☒ No	T106
Does the partnership have to file Form T1134 in respect of any foreign affiliates in the fiscal period?	**172**	☐ Yes	☒ No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property or federal, provincial, territorial or municipal political contributions?	**202**	☐ Yes	☒ No	2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☐ Yes	☒ No	5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ Yes	☒ No	6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ Yes	☐ No	8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	**212**	☐ Yes	☒ No	12
Is the partnership allocating any investment tax credits (ITCs)? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	**231**	☐ Yes	☒ No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	**232**	☐ Yes	☒ No	T661
Did the partnership allocate renounced resource expenses to its members?	**252**	☐ Yes	☒ No	52
Did the partnership own or hold specified foreign property for which the total cost amount, at any time in the fiscal period, was more than CAN$100,000?	**259**	☐ Yes	☒ No	T1135
Is the partnership allocating any Canadian journalism labour tax credits?	**260**	☐ Yes	☒ No	58

Protected B when completed

Partnership account number: **001** 78830 4327 RZ0001

Fiscal period end Year Month Day **061** 2021-12-31

Additional information

Did the partnership use the international financial reporting standards (IFRS) when it prepared its financial statements?	**270**	☐ Yes	☒ No
Was a slip issued to one or more nominees or agents?	**271**	☐ Yes	☒ No
Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2?	**272**	☐ Yes	☒ No
Does the partnership have one or more new nominees or agents?	**273**	☐ Yes	☒ No
Did the partnership allocate any amount of income tax deducted at source?	**274**	☐ Yes	☒ No
Did the partnership make any other election(s) under the Act during the fiscal period?	**275**	☐ Yes	☒ No

If **Yes**, attach a copy of each election form to this return.

Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed?	**277**	☐ Yes	☒ No

If you answered **Yes** to line 277, provide the business number(s) of the predecessor partnership(s): **278**

279

Was the partnership inactive throughout the fiscal period this information return applies to?	**280**	☐ Yes	☒ No

If **Yes**, see Guide T4068 to verify your filing requirements.

Did members of the partnership immigrate to Canada during the fiscal period?	**291**	☐ Yes	☒ No
Did members of the partnership emigrate from Canada during the fiscal period?	**292**	☐ Yes	☒ No
If the major business activity is construction, did you have any subcontractors during the fiscal period?	**295**	☐ Yes	☒ No
Did the partnership report its farming or fishing income using the cash method?	**296**	☐ Yes	☒ No
Is this a publicly traded partnership?	**297**	☐ Yes	☒ No
If you answered **Yes** to line 297, did the partnership issue T5008 information slips to report transactions of interests in the partnership?	**298**	☐ Yes	☐ No

Miscellaneous information

For tax deductions withheld at source, was an NR4 information return filed for the fiscal period?	**301**	☐ Yes	☒ No

If you answered **Yes** to line 301, enter the non-resident account number: **302**

If you answered **Yes** to line 301, were NR4 slips issued?	**303**	☐ Yes	☐ No
Is this partnership a specified investment flow-through (SIFT) partnership?	**304**	☐ Yes	☒ No

If you answered **Yes** to line 304, enter the taxable non-portfolio earnings for the fiscal period: **305**

If you answered **Yes** to line 304, enter the tax payable under Part IX.1 for the fiscal period: **306**

Enter the amount of the late-filing penalty from line 307 of Schedule 52: **307**

Amount of payment enclosed with this return: **308**

Protected B when completed

Fiscal period end

Year Month Day

Partnership account number:

001 78830 4327 RZ0001

061 2021-12-31

Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15) of the Act

400 ______ Name of designated partner

402 ______ Identification number

Additional information for tax shelters only

Principal promoter

500 ______ Last name (print)

501 ______ First name (print)

502 ______ Identification number

Certification

950 I, King — Last name (print)

951 Glen — First name (print)

954 CFO — Position or title

certify that the information given on this form is correct and complete. I also certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as noted in a statement attached to this return.

955 2022-05-26 — Year Month Day

______ Signature of the authorized partner

956 (905) 994-3643 — Telephone number

Language of correspondence

Indicate your language of correspondence . . . . **990** ☒ English ☐ French

Privacy Statement

Personal information is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties, or other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at **canada.ca/cra-info-source**.

Canada Revenue Agency | Agence du revenu du Canada

T5013
SCHEDULE 100

PARTNERSHIP'S BALANCE SHEET INFORMATION

Partnership name	Partnership account Number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31	Original ☒ Amended ☐

Is this a NIL schedule? . . . . . **999** Yes ☐ No ☒

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	39,921,773.00	15,201,269.00
	Total tangible capital assets	2008	+	972,141,190.00	524,760,661.00
	Total accumulated amortization of tangible capital assets	2009	–	3,663,893.00	2,428,577.00
	Total intangible capital assets	2178	+	54,796.00	54,796.00
	Total accumulated amortization of intangible capital assets	2179	–	4,110.00	2,740.00
	Total long-term assets	2589	+	62,740,562.00	2,046,966.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	1,071,190,318.00	539,632,375.00
	Liabilities				
	Total current liabilities	3139	+	182,619,403.00	117,862,678.00
	Total long-term liabilities	3450	+	871,630,262.00	405,272,880.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	1,054,249,665.00	523,135,558.00
	Partner's capital				
	Total partners' capital (mandatory field)	3575	+	16,940,653.00	16,496,817.00
	Total liabilities and partners' capital	3585	=	1,071,190,318.00	539,632,375.00

* Generic item

Current Assets

SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI		Current year	Prior year
	Cash and deposits				
____________	* Cash and deposits	1000		35,980,389.00	9,759,060.00
	Cash and deposits		+	35,980,389.00	9,759,060.00
	Accounts receivable				
____________	* Accounts receivable	1060		227,528.00	5,527.00
	Accounts receivable		+	227,528.00	5,527.00
	Inventories				
____________	* Inventories	1120		384,068.00	396,804.00
	Inventories		+	384,068.00	396,804.00
	Due from/investment in related parties				
____________	* Due from/investment in related parties	1400		7,651.00	82,657.00
	Due from/investment in related parties		+	7,651.00	82,657.00
	Other current assets				
____________	* Other current assets	1480		3,322,137.00	4,957,221.00
	Other current assets		+	3,322,137.00	4,957,221.00
____________	**Total current assets**	1599	=	39,921,773.00	15,201,269.00

* Generic item

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
	Machinery, equipment, furniture and fixtures						
	* Machinery, equipment, furniture, and fixtures	1740	+	56,887,094.00			56,920,806.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–	3,663,893.00	2,428,577.00
	Total			56,887,094.00		3,663,893.00	
	Other tangible capital assets						
	Other capital assets under construction	1920	+	915,254,096.00			467,839,855.00
	Total			915,254,096.00			
	Total tangible capital assets	2008	=	972,141,190.00			524,760,661.00
	Total accumulated amortization of tangible capital assets	2009			=	3,663,893.00	2,428,577.00

* Generic item

Attached Schedule with Total

Tangible capital property – GIFI code 1740 – Machinery, equipment, furniture, and fixtures

Title Tangible capital property – GIFI code 1740 – Machinery, equipment, furniture

Explanatory note

Description	Operator (Note)	Amount	
Poles & Fixtures (G1-14)		22,057,899	00
Overhead Conuctors and devices (G1-14)	+	22,511,453	00
Station Equipment (G1-14)	+	12,317,742	00
	+		
	Total	56,887,094	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

GIFI code 1741 – Accumulated amortization of machinery, equipment, furniture, and fixtures

Title GIFI code 1741 – Accumulated amortization of machinery, equipment, furnitu

Explanatory note

Description	Operator (Note)	Amount	
Station Equipment		738,923	00
Poles & Fixtures	+	1,470,527	00
Overhead Conuctors and devices	+	1,454,443	00
	+		
	Total	3,663,893	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Intangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2178/2179

Account	Description	GIFI		Intangible capital assets		Accumulated amortization	Prior year
	Intangible assets						
	Rights	2024	+	54,796.00			54,796.00
	Accumulated amortization of rights	2025			–	4,110.00	2,740.00
	Total			54,796.00		4,110.00	
	Total intangible capital assets	2178	=	54,796.00			54,796.00
	Total accumulated amortization of intangible capital assets	2179			=	4,110.00	2,740.00

* Generic item

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
	Other long-term assets				
	* Other long-term assets	2420		62,740,562.00	2,046,966.00
	Other long-term assets		+	62,740,562.00	2,046,966.00
	Total long-term assets	2589	=	62,740,562.00	2,046,966.00

* Generic item

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		170,637,647.00	116,158,333.00
	Amounts payable and accrued liabilities		+	170,637,647.00	116,158,333.00
Due to related parties					
	* Due to related parties	2860		11,981,756.00	1,704,345.00
	Due to related parties		+	11,981,756.00	1,704,345.00
	Total current liabilities	3139	=	182,619,403.00	117,862,678.00

* Generic item

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		818,344,443.00	350,716,664.00
	Long-term debt		+	818,344,443.00	350,716,664.00
Other long-term liabilities					
	* Other long-term liabilities	3320		53,285,819.00	54,556,216.00
	Other long-term liabilities		+	53,285,819.00	54,556,216.00
	Total long-term liabilities	3450	=	871,630,262.00	405,272,880.00

* Generic item

Attached Schedule with Total

GIFI code 3140 – Long-term debt

Title GIFI code 3140 – Long-term debt

Explanatory note

Description	Operator (Note)	Amount	
Senior Banks (G1-14)		547,800,000	00
Ontario Loan (G1-14)	+	278,000,000	00
Unamortized financing cost	+	-7,455,557	00
	+		
	Total	818,344,443	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Partner's capital

SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI		Current year	Prior year
	Total net income/loss				
	Net income/loss	3545	+	443,836.00	3,453.00
	Total net income/loss	3550	=	443,836.00	3,453.00
	General partners' capital				
	General partners' capital beginning balance	3551	+	-372.00	-372.00
	General partners' net income (loss)	3552	+	45.00	
	General partners' capital ending balance	3560	=	-327.00	-372.00
	Limited partners' capital				
	Limited partners' capital beginning balance	3561	+	16,497,189.00	16,493,736.00
	Limited partners' net income (loss)	3562	+	443,791.00	3,453.00
	Limited partners' capital ending balance	3571	+	16,940,980.00	16,497,189.00
	Total partners' capital	3575	=	16,940,653.00	16,496,817.00

* Generic item

Attached Schedule with Total

GIFI code 3561 – Limited partners' capital beginning balance

Title GIFI code 3561 – Limited partners' capital beginning balance

Explanatory note

Description	Operator (Note)	Amount	
First Nations LP (G1-5)		9,069,523	00
Fortis (WP) LP (G1-5)	+	7,427,666	00
	+		
	Total	16,497,189	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

GIFI code 3564 – Limited partners' contributions during the fiscal period

Title GIFI code 3564 – Limited partners' contributions during the fiscal period

Explanatory note

Description	Operator (Note)	Amount
First Nation LP		
Fortis LP	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Canada Revenue Agency / Agence du revenu du Canada

T5013
SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31	Original ☒ Amended ☐

Income statement information

Description **GIFI**

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Operating name **0001**

Description of the operation **0002**

Sequence Number **0003** 01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+		
	Cost of sales	8518	–		
	Gross profit/loss	8519	=		
	Cost of sales	8518	+		
	Total operating expenses	9367	+	1,557,036.00	1,255,666.00
	Total expenses (mandatory field)	9368	=	1,557,036.00	1,255,666.00
	Total revenue (mandatory field)	8299	+	2,000,872.00	1,259,119.00
	Total expenses (mandatory field)	9368	–	1,557,036.00	1,255,666.00
	Net non-farming income	9369	=	443,836.00	3,453.00
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before extraordinary items – all operations	9970	=	443,836.00	3,453.00
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	443,836.00	3,453.00

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	Investment revenue				
	* Investment revenue	8090		761,092.00	30,387.00
	Interest from other Canadian sources	8094		1,035.00	127.00
	Investment revenue		+	762,127.00	30,514.00
	Other revenue				
	* Other revenue	8230		1,238,745.00	1,228,605.00
	Other revenue		+	1,238,745.00	1,228,605.00
	Total revenue	8299	=	2,000,872.00	1,259,119.00

* Generic item

Attached Schedule with Total

GIFI code 8094 – Amount – Interest from other Canadian sources

Title GIFI code 8094 – Amount – Interest from other Canadian sources

Explanatory note

Description	Operator (Note)	Amount
Interest Income		1,035 00
	+	
	+	
	Total	1,035 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	1,238,745.00	1,228,605.00
	Other expenses				
	General and administrative expenses	9284		318,291.00	27,061.00
	Other expenses		+	318,291.00	27,061.00
	Total operating expenses	9367	=	1,557,036.00	1,255,666.00

* Generic item

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Financial Statement Notes Checklist

Protected B when completed

T5013
Schedule 141

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31	☒ Original ☐ Amended

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements
- For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 forms), and Guide RC4088, General Index of Financial Information (GIFI)
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, Partnership Financial Return

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** ☒ Yes ☐ No

Is the accountant connected with the partnership? * . . . **097** ☐ Yes ☒ No

Note: If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.

* A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the accountant's highest level of involvement: **198**

Completed an auditor's report . . . ☒ 1

Completed a review engagement report . . . ☐ 2

Conducted a compilation engagement . . . ☐ 3

Part 3 – Reservations

If you selected option 1 or option 2 **in part 2** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** ☐ Yes ☒ No

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: **110**

Prepared the information return (financial statements prepared by client) . . . ☒ 1

Prepared the information return and the financial information contained therein (financial statements have not been prepared) . . . ☐ 2

Were notes to the financial statements prepared? . . . **101** ☒ Yes ☐ No

If **yes**, answer the following four questions:

Are subsequent events mentioned in the notes? . . . **104** ☐ Yes ☒ No

Is re-evaluation of asset information mentioned in the notes? . . . **105** ☐ Yes ☒ No

Is contingent liability information mentioned in the notes? . . . **106** ☐ Yes ☒ No

Is information regarding commitments mentioned in the notes? . . . **107** ☒ Yes ☐ No

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below. . . . **108** ☐ Yes ☒ No

Are you filing joint venture(s) financial statements? . . . **109** ☐ Yes ☐ No

Approval code: RC-21-P010

Partnership account number	Fiscal period-end Year Month Day
78830 4327 RZ0001	2021-12-31

Protected B when completed

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? . . . . **200** ☐ Yes ☒ No

If **yes**, enter the amount recognized:

In net income Increase (decrease)

Property, plant and equipment	**210**	
Intangible assets	**215**	
Investment property	**220**	
Biological assets	**225**	
Financial instruments	**230**	
Other	**235**	

In other comprehensive income Increase (decrease)

Property, plant, and equipment	**211**	
Intangible assets	**216**	
Financial instruments	**231**	
Other	**236**	

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? . . . . **250** ☐ Yes ☒ No

Did the partnership apply hedge accounting during the fiscal period? . . . . **255** ☐ Yes ☒ No

Did the partnership discontinue hedge accounting during the fiscal period? . . . . **260** ☐ Yes ☒ No

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? . . . . **265** ☐ Yes ☒ No

If **yes**, you have to maintain a separate reconciliation.

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31

Is this a NIL schedule? . . . . **999** Yes ☐ No ☒

Assets – lines 1000 to 2599

1000	35,980,389.00	**1060**	227,528.00	**1120**	384,068.00
1400	7,651.00	**1480**	3,322,137.00	**1599**	39,921,773.00
1740	56,887,094.00	**1741**	-3,663,893.00	**1920**	915,254,096.00
2008	972,141,190.00	**2009**	-3,663,893.00	**2024**	54,796.00
2025	-4,110.00	**2178**	54,796.00	**2179**	-4,110.00
2420	62,740,562.00	**2589**	62,740,562.00	**2599**	1,071,190,318.00

Liabilities – lines 2600 to 3499

2620	170,637,647.00	**2860**	11,981,756.00	**3139**	182,619,403.00
3140	818,344,443.00	**3320**	53,285,819.00	**3450**	871,630,262.00
3499	1,054,249,665.00				

Partner's capital – lines 3540 to 3575

3545	443,836.00	**3550**	443,836.00	**3551**	-372.00
3552	45.00	**3560**	-327.00	**3561**	16,497,189.00
3562	443,791.00	**3571**	16,940,980.00	**3575**	16,940,653.00
3585	1,071,190,318.00				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8090	761,092.00	**8094**	1,035.00	**8230**	1,238,745.00
8299	2,000,872.00				

Operating expenses – lines 8520 to 9369

8670	1,238,745.00	**9284**	318,291.00	**9367**	1,557,036.00
9368	1,557,036.00	**9369**	443,836.00		

Farming revenue – lines 9370 to 9659

9659 0.00

Farming expenses – lines 9660 to 9899

9898 0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	443,836.00	**9999**	443,836.00

Approval code: RC-21-P010

Canada Revenue Agency
Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Protected B when completed

T5013
Schedule 1

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Is this a NIL schedule? **999** ☐ Yes ☒ No

(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140			**500**		443,836.00
Add:					
Provision for Part IX.1 specified investment flow through (SIFT) taxes	**101**				
Amortization/depreciation of tangible assets	**104**	1,238,745.00			
Amortization of natural resource assets	**105**				
Amortization of intangible assets	**106**				
Recapture of capital cost allowance from Schedule 8	**107**				
Income or loss for tax purposes from partnerships	**109**				
Loss in equity of affiliates	**110**				
Loss on disposal of assets per financial statements	**111**				
Charitable donations and gifts from Schedule 2	**112**				
Political contributions from Schedule 2	**114**				
Current fiscal period's holdbacks	**115**				
Deferred and prepaid expenses	**116**				
Depreciation in inventory – end of fiscal period	**117**				
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	**118**				
Capitalized interest and property taxes on vacant land	**119**				
Non-deductible club dues and fees	**120**				
Non-deductible meals and entertainment expenses	**121**				
Non-deductible automobile expenses	**122**				
Non-deductible life insurance premiums	**123**				
Non-deductible company pension plans	**124**				
Reserves from financial statements – balance at the end of the fiscal period	**126**				
Soft costs on construction and renovation of buildings	**127**				
Salaries and wages paid to partners deducted on financial statements	**150**				
Cost of products available for sale that were consumed	**151**				
Personal expenses of the partners paid by the partnership	**152**				
Dividend rental arrangement compensation payment deductions	**154**				
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	**155**				
Certain fines and penalties	**156**				
Amount from line 508 on page 2 of this schedule	**199**	31,652.00			
Total (**Add** lines 101 to 199. Enter this amount on line 501)		1,270,397.00 ▶	**501**	+	1,270,397.00
Deduct: Amount from line 511 on page 3 of this schedule			**502**	–	4,394,863.50
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			**503**	=	-2,680,630.50
Deduct: Net income (loss) for general partners			**504**	–	-268.06
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			**505**	=	-2,680,362.44

Partnership account number
78830 4327 RZ0001

Fiscal period end
Year Month Day
2021-12-31

Protected B when completed

Add:

Accounts payable and accruals for cash basis – closing	201				
Accounts receivable and prepaid for cash basis – opening	202				
Accrual inventory – opening	203				
Accrued dividends – prior fiscal period	204				
Book loss on joint ventures or partnerships	205				
Capital items expensed	206				
Debt issue expense	208				
Deemed dividend income	209				
Deemed interest on loans to non-residents	210				
Deemed interest received	211				
Development expenses claimed in current fiscal period	212				
Dividend stop-loss adjustment	213				
Dividends credited to the investment account	214				
Exploration expenses claimed in current fiscal period	215				
Financing fees deducted in books	216				
Foreign accrual property income	217				
Foreign affiliate property income	218				
Foreign exchange included in retained earnings	219				
Gain on settlement of debt – income inclusion under subsection 80(13)	220				
Interest paid on income debentures	221				
Limited partnership losses	222				
Loss from international banking centres	223				
Mandatory inventory adjustment – included in current fiscal period	224				
Non-deductible advertising	226				
Non-deductible interest	227				
Non-deductible legal and accounting fees	228				
Optional value of inventory – included in current fiscal period	229				
Other expenses from financial statements	230				
Recapture of SR&ED expenditures from Form T661	231				
Resource amounts deducted	232				
Sales tax assessments	234				
Write-down of capital property	236				
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237				
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238				
Taxable/Non-deductible other comprehensive income items	239				
Total (**Add** lines 201 to 239. Enter this amount on line 506)			▶	506	+

Other additions:

600	Asset Retirement	290	31,652.00			
601		291				
602		292				
603		293				
604		294				
	Total (**Add** lines 290 to 294. Enter this amount on line 507)		31,652.00	▶	507	+ 31,652.00

Total (**Add** lines 506 and 507) 508 = 31,652.00
Enter the amount from line 508 on line 199 on page 1 of this schedule.

Partnership account number	Fiscal period end Year Month Day
78830 4327 RZ0001	2021-12-31

Protected B when completed

Deduct:

Accounts payable and accruals for cash basis – opening	300	
Accounts receivable and prepaid for cash basis – closing	301	
Accrual inventory – closing	302	
Accrued dividends – current fiscal period	303	
Bad debt	304	
Book income of joint venture or partnership	305	
Equity in income from affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment – included in prior fiscal period	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses – broadcasting	311	
Non-Canadian advertising expenses – printed materials	312	
Optional value of inventory – included in prior fiscal period	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payments	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	
Non-taxable/Deductible other comprehensive income items	347	

Other less common deductions:

700	Amortization of deferred contribution	390	1,238,745.00
701	20(1)(e) Financing fees	391	3,120,958.00
702	Gain on Disposal	392	31,652.00
703		393	
704		394	

Total (**Add** lines 300 to 394. Enter this amount on line 509) 4,391,355.00 ▶ 509 + 4,391,355.00

Other deductions:

Gain on disposal of assets per financial statements	401	
Non-taxable dividends under section 83	402	
Capital cost allowance from Schedule 8	403	3,508.50
Terminal loss from Schedule 8	404	
Foreign non-business tax deduction under subsection 20(12)	407	
Prior fiscal period's holdbacks	408	
Deferred and prepaid expenses	409	
Depreciation in inventory – end of prior fiscal period	410	
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	
Reserves from financial statements – balance at the beginning of the fiscal period	414	
Patronage dividends	416	
Contributions to deferred income plans	417	

Total (**Add** lines 401 to 417. Enter this amount on line 510) 3,508.50 ▶ 510 + 3,508.50

Total (**Add** lines 509 and 510) 511 = 4,394,863.50
Enter this amount on line 502 on page 1 of this schedule.

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Capital Cost Allowance (CCA)

T5013 Schedule 8
Protected B when completed

Partnership name	Partnership account number	Fiscal period-end Year Month Day	☒ Original ☐ Amended
Wataynikaneyap Power LP	78830 4327 RZ0001	2021-12-31	

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period and to account for acquisitions or dispositions of depreciable property or both
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms)
- If you do not have enough space to list all the information, use an additional T5013 Schedule 8
- Attach the original copy of this completed schedule to form T5013 FIN, Partnership Financial Return

1 Class number See Note 1 200	2 Undepreciated capital cost (UCC) at the beginning of the fiscal period 201	3 Cost of acquisitions during the fiscal period (new property must be available for use) See Note 2 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP) or zero-emission vehicle (ZEV) See Note 3 225	5 Adjustments and transfers (show amounts that reduce the UCC in brackets) See Note 4 205	6 Amount from column 5 that is assistance received or receivable during the fiscal period for a property, subsequent to its disposition See Note 5 221	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition See Note 6 222	8 Proceeds of dispositions See Note 7 207	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See Note 8
14.1	50,121.45							50,121.45
99	467,827,924.01	447,414,241.00		-105,667,932.00				809,574,233.01
47				105,667,932.00				105,667,932.00
Totals	467,878,045.46	447,414,241.00						915,292,286.46

10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the fiscal period (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the fiscal period (column 11 **multiplied** by the relevant factor) See Note 9	13 UCC adjustment for property acquired during the fiscal period other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See Note 10 224	14 CCA rate % See Note 11 212	15 Recapture of CCA See Note 12 213	16 Terminal loss See Note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See Note 14 217	18 UCC at the end of the fiscal period (column 9 **minus** column 17) 220
				5.00			3,508.50	46,612.95
			223,707,120.50					809,574,233.01
				8.00				105,667,932.00
			223,707,120.50		230	240	250	915,288,777.96
				Totals			3,508.50	

Enter the amount from line 230 on line 107 of the T5013 Schedule 1.
Enter the amount from line 240 on line 404 of the T5013 Schedule 1.
Enter the amount from line 250 on line 403 of the T5013 Schedule 1.

Approval code: RC-21-P010

Canada

Note 1 If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 2 Include any property acquired in previous fiscal periods that has now become available for use, net of any assistance received or entitled to be received in the fiscal period from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3 AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a motor vehicle included in class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. The Government proposes to create class 56 for zero-emission automotive equipment and vehicles that currently do not benefit from the accelerated rate provided by classes 54 and 55. Class 56 would apply to eligible zero-emission automotive equipment and vehicles that are acquired after March 1, 2020, and became available for use before 2028. Columns 4, 10, 11, 12 and 13 also apply for additions of class 56 property. See Guide T4068 for more information.

Note 4 Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 9). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the fiscal period for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the Guide T4068 for other examples of adjustments and transfers to include in column 5.

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 5 Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6 Include all amounts you have repaid during the fiscal period with respect to any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d), and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 7 For each property disposed of during the fiscal period, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

The proceeds of disposition of a ZEV that has been included in class 54 and that is subject to the $55,000 (plus sales tax) capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 (plus sales tax) as a proportion of the actual cost of the vehicle.

Note 8 If the amount in column 5 reduces the UCC (as shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 9 The relevant factors for property of a class in Schedule II, that is AIIP or included in Classes 54 to 56, available for use before 2024 are:

- 2 1/3 for property in classes 43.1, 54 and 56
- 1 1/2 for property in class 55
- 1 for property in classes 43.2 and 53
- 0 for property in classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information), and
- 0.5 for all other property that is AIIP

Note 10 The UCC adjustment for property acquired during the fiscal period other than AIIP and ZEV (formerly known as the half-year rule or 50% rule) does not apply to certain property. For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11 Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12 If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do **not** apply to passenger vehicles in class 10.1.

Note 13 If no property is left in the class at the end of the fiscal period and there is still a positive amount in column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:

- passenger vehicles in class 10.1
- property in class 14.1, unless you have ceased carrying on the business to which it relates, or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met.

Note 14 If the fiscal period is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4068 for more information. For property in class 10.1 disposed of during the fiscal period, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the fiscal period. For AIIP listed below, the maximum first fiscal period allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the fiscal period of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the fiscal period and the UCC at the end of the fiscal period (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Canada Revenue Agency Agence du revenu du Canada

Partner's Ownership and Account Activity

Protected B when completed

T5013
Schedule 50

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	788304327RZ0001	2021-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	**010**	3
Number of partners who disposed of all, or part of, their partnership interest	**011**	
Number of nominees or agents	**012**	
Total of all amounts from line 220	**015**	-2,680,630.50

Partner 1	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
First Nation LP	722558525RZ0001	3	0	54.2464	☐ Yes ☒ No	-1,367,121.56	10963826.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-1,591,851.69						

Partner 2	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
Fortis (WP) LP	749436499RZ0001	3	0	45.7536	☐ Yes ☒ No	-1,313,240.88	9247312.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-1,529,114.01						

Approval code: RC-21-P010

Protected B when completed

Partner 3	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
Wataynikaneyap Power GP Inc.	815046362RC0001	2	2		☐ Yes ☒ No	-268.06	N/A

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-312.13						

Partner 4	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

List Detailing the Partner's Ownership and Account Activity

Partnership Wataynikaneyap Power LP

Partner		Partner code	Percentage (%) of partner's interest	Line 220		Line 300		Line 320		Line 330		Line 340		Line 350	
1	First Nation LP	0	54.2464	-1,367,121	56	10,963,826	00	-1,591,851	69						
2	Fortis (WP) LP	0	45.7536	-1,313,240	88	9,247,312	00	-1,529,114	01						
3	Wataynikaneyap Power GP Inc.	2		-268	06			-312	13						
			Total	-2,680,630	50	20,211,138	00	-3,121,277	83						

Canada Revenue Agency
Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le
YYYY-MM-DD
2021-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code – Code de l'associé: **002** 0

Country code – Code du pays: **003** CAN

Recipient type – Genre de bénéficiaire: **004** 4

Partnership account number (15 characters) – Numéro de compte de la société de personnes (15 caractères): **001** 788304327RZ0001

Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire: **010** -1,367,121 56

Total business income (loss) – Total du revenu (de la perte) d'entreprise: **020**

Partner's identification number – Numéro d'identification de l'associé: **006** 722558525RZ0001

Partner's share (%) of partnership – Part de l'associé (%) dans la société de personnes: **005** 51.000000

Total capital gains (losses) – Total des gains (pertes) en capital: **030**

Capital cost allowance – Déduction pour amortissement: **040** 1,789 34

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

► First Nation LP

300 Anemki Place, Suite C
Fort William First Nation ON P7J 1H9

Box Case	Code	Amount – Montant		Box Case	Code	Amount – Montant	
104		-1,367,121	56	105		8,067,649	07
106		8,067,649	07	118		1,020,444	72

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency
Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le
YYYY-MM-DD
2021-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant
Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code – Code de l'associé: **002** 0

Country code – Code du pays: **003** CAN

Recipient type – Genre de bénéficiaire: **004** 4

Partnership account number (15 characters) – Numéro de compte de la société de personnes (15 caractères): **001** 788304327RZ0001

Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire: **010** -1,313,240 88

Total business income (loss) – Total du revenu (de la perte) d'entreprise: **020**

Partner's identification number – Numéro d'identification de l'associé: **006** 749436499RZ0001

Partner's share (%) of partnership – Part de l'associé (%) dans la société de personnes: **005** 48.990000

Total capital gains (losses) – Total des gains (pertes) en capital: **030**

Capital cost allowance – Déduction pour amortissement: **040** 1,718 81

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

► Fortis (WP) LP
1130 Bertie Street
PO BOX 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		-1,313,240 88	105		6,465,278 53
106		6,465,278 53	118		980,227 19

Box – Case	Code	Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

T5013 (21) **Protected B** when completed – **Protégé B** une fois rempli

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le

YYYY-MM-DD
2021-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 2	**003** CAN	**004** 3

Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) Total du revenu (de la perte) d'entreprise
001 788304327RZ0001	**010**	**020** -268 06

Partner's identification number Numéro d'identification de l'associé	Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	Total capital gains (losses) Total des gains (pertes) en capital	Capital cost allowance Déduction pour amortissement
006 815046362RC0001	**005** 0.010000	**030**	**040** 0 35

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

► Wataynikaneyap Power GP Inc.

1130 Bertie Street
P.O. Box 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116		-268 06	118		200 09

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency | Agence du revenu du Canada

Protected B when completed

Summary of Partnership Income

T5013 Summary

Fill out this summary and related slips using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).

The **partnership information return** is composed of three parts:

- T5013 FIN, Partnership Financial Return
- All the T5013 schedules the partnership has to file, depending on their fiscal situation
- T5013, Statement of Partnership Income slip, as well as this summary

If you make certain payments to a non-resident of Canada, the amounts should be reported on an NR4 return. For more information, see Guide T4061, NR-4 – Non-Resident Tax Withholding, Remitting and Reporting.

For more information on filing the partnership information return, go to **canada.ca/t5013-filing-requirements**.

Do not use this area.

50 ☐☐☐☐ **1616**

Part 1 – Identification

Partnership's account number: 78830 4327 RZ0001

Fiscal period start (Year Month Day): 2021-01-01

Fiscal period-end (Year Month Day): 2021-12-31

Partnership's name: Wataynikaneyap Power LP

Postal or ZIP code: L2A 5Y2

If you are a nominee or agent, enter your information below

Nominee or agent's account number:

Nominee or agent name:

Postal or ZIP code:

If the partnership is a tax shelter (TS), enter the TS identification number . . . .

Part 2 – Totals from T5013 slips

Total number of T5013 information slips attached	009	3
Total limited partner's business income (loss)	010	-2,680,362.44
Total business income (loss)	020	-268.06
Total capital gains (losses)	030	
Capital cost allowance	040	3,508.50

Complete the six generic boxes identified below taken from the T5013 slips

Canadian and foreign net rental income (loss)	110	
Professional income (loss)	120	
Renounced Canadian exploration expenses	190	
Renounced Canadian development expenses	191	
Expenses qualifying for an Investment Tax Credit (ITC)	194	
Total carrying charges	210	

Part 3 – Contact information

076 Person to contact about this summary: Ernst & Young LLP

078 Telephone number: (416) 864-1234

Part 4 – Certification

I certify that the information given on this form is correct and complete.

Year Month Day: 2022-05-26

Signature of authorized person:

Position or office: CFO

Prepared by: Ernst & Young LLP

Year Month Day: 2022-05-26

Part 5 – Privacy statement

Personal information is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties, or other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at **canada.ca/cra-info-source**.

ATTACHMENT 5

2022 Annual Report for Fortis Inc.

St. John's, NL - February 10, 2023

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2022 RESULTS

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2022 fourth quarter and annual financial results[1].

Highlights

- Reported net earnings of $1.3 billion, or $2.78 per common share in 2022
- Adjusted net earnings per common share[2] of $2.78, up from $2.59 in 2021, representing ~7% annual EPS growth
- Capital expenditures[2] of $4.0 billion, with over $600 million focused on delivering cleaner energy, yielding ~7% rate base growth[3]
- Scope 1 emissions 28% below 2019 levels; 75% emissions reduction by 2035 target on track in support of 2050 net-zero goal
- Capital structure complaint filed against ITC Midwest denied by FERC

"2022 was a year of execution with strong financial, operational and sustainability results across our utilities," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "We invested over $4 billion in capital, delivered strong EPS and rate base growth, and further reduced our carbon emissions. We also outperformed safety and reliability industry averages and were recognized as a leader in Canada for our governance practices."

"With a focus on organic growth, we also announced our largest five-year capital plan of $22.3 billion representing steady rate base growth of 6% and supporting annual dividend growth guidance of 4-6% through 2027," said Mr. Hutchens. "We appreciate the dedication and hard work of our people to make 2022 another successful year."

Net Earnings

The Corporation reported net earnings attributable to common equity shareholders ("Net Earnings") for 2022 of $1.3 billion, or $2.78 per common share, compared to $1.2 billion, or $2.61 per common share for 2021. The increase was primarily driven by rate base growth across our utilities. The increase was also due to higher electricity sales and transmission revenue in Arizona, and higher earnings at Aitken Creek. The translation of U.S. dollar-denominated subsidiary earnings at a higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results.

Growth in earnings was tempered by certain discrete items at ITC, including costs associated with the suspension of the Lake Erie Connector project, the revaluation of deferred income tax assets, and an adjustment in 2021 related to interest rate swaps. Losses on investments that support retirement benefits at UNS Energy and ITC, higher operating costs at Central Hudson related to the implementation of a new customer information system, and higher corporate costs also impacted results. In addition, net earnings per common share reflected an increase in the weighted average number of common shares outstanding largely associated with the Corporation's dividend reinvestment plan.

For the fourth quarter of 2022, Net Earnings were $370 million, or $0.77 per common share, compared to $328 million or $0.69 per common share for the same period in 2021. The increase was due to rate base growth, higher retail electricity sales and transmission revenue at UNS Energy, higher hydroelectric production in Belize, and the timing of expenses at FortisAlberta. The higher foreign exchange rate and lower stock based compensation costs, as discussed above, also favourably impacted results. The increase was partially offset by higher corporate costs as well as lower earnings at Central Hudson due to the timing of approval of its rate application in 2021, and for net earnings per common share, an increase in the weighted average number of common shares.

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[1] Financial information is presented in Canadian dollars unless otherwise specified.

[2] Non-U.S. GAAP Measures - Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America and may not be comparable to similar measures presented by other entities. Fortis presents these non-U.S. GAAP measures because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects. Refer to the Non-U.S. GAAP Reconciliation provided herein.

[3] Calculated using a constant United States dollar-to-Canadian dollar exchange rate.

Adjusted Net Earnings[2]

Adjusted net earnings attributable to common equity shareholders ("Adjusted Net Earnings") excludes non-recurring items and the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek. Adjusted Net Earnings of $1.3 billion for 2022, or $2.78 per common share, were $110 million, or $0.19 per common share higher than 2021. For the fourth quarter of 2022, Adjusted Net Earnings were $347 million, or $0.72 per common share, an increase of $47 million, or $0.09 per common share compared to the same period in 2021. The increase in adjusted earnings for the fourth quarter and the year was driven by the same factors discussed for Net Earnings.

Capital Expenditures[2]

Capital expenditures were $4.0 billion, consistent with the 2022 capital plan, and mainly consisted of regulated investments focused on system resiliency, grid modernization and sustainable energy, including more than $600 million in cleaner energy investments. Capital expenditures increased midyear rate base to $34.1 billion, representing 7% growth over 2021[3].

The Corporation's five-year capital plan for 2023 through 2027 is $22.3 billion, the largest in the Corporation's history. In total, Fortis expects to invest $5.9 billion in cleaner energy over the next five years. These investments will focus on connecting renewables to the grid, including Tranche 1 of the Midcontinent Independent System Operator ("MISO") long-range transmission plan ("LRTP"), renewable and storage investments in Arizona and the Caribbean, and cleaner fuel solutions in British Columbia. The plan incorporates key customer affordability considerations, recognizing the impacts of inflation and elevated commodity costs on customer rates, while ensuring reliable and resilient energy delivery service as we transition to a cleaner energy future.

The five-year capital plan is expected to be funded primarily by cash from operations, debt issued at the regulated utilities and common equity from the Corporation's dividend reinvestment plan.

Non-U.S. GAAP Reconciliation

Periods ended December 31	Quarter			Annual		
($ millions, except earnings per share)	**2022**	2021	Variance	**2022**	2021	Variance
Adjusted Net Earnings						
Net Earnings	**370**	328	42	**1,330**	1,231	99
Adjusting items:						
Unrealized gain on mark-to-market of derivatives[4]	**(23)**	(28)	5	**(20)**	(12)	(8)
Lake Erie Connector project suspension costs[5]	**—**	—	—	**10**	—	10
Revaluation of deferred income tax assets[6]	**—**	—	—	**9**	—	9
Adjusted Net Earnings	**347**	300	47	**1,329**	1,219	110
Adjusted Basic EPS *($)*	**0.72**	0.63	0.09	**2.78**	2.59	0.19
Capital Expenditures						
Additions to property, plant and equipment	**987**	897	90	**3,587**	3,189	398
Additions to intangible assets	**127**	77	50	**278**	197	81
Adjusting item:						
Wataynikaneyap Transmission Power Project[7]	**34**	35	(1)	**169**	178	(9)
Capital Expenditures	**1,148**	1,009	139	**4,034**	3,564	470

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[4] Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $8 million and $7 million for the three and twelve months ended December 31, 2022, respectively ($11 million and $5 million for the three and twelve months ended December 31, 2021, respectively).

[5] Represents costs incurred upon the suspension of the Lake Erie Connector project, net of income tax recovery of $nil and $4 million for the three and twelve months ended December 31, 2022, respectively.

[6] Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa.

[7] Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project.

Regulatory Updates

In November 2022, FERC issued an order denying the complaint filed by the Iowa Coalition for Affordable Transmission ("ICAT"), which sought to lower ITC Midwest's equity ratio from 60% to 53%. FERC concluded that ICAT had not demonstrated that ITC Midwest failed to meet the three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In December 2022, ICAT filed a request for rehearing with FERC. The Corporation continues to believe the complaint is without merit.

Focus on Sustainability

Fortis achieved a 28% reduction in Scope 1 emissions through 2022 compared to 2019 levels, equivalent to taking approximately 760,000 vehicles off the road in one year. The closure of the 170-megawatt coal-fired San Juan Generating Station in Arizona in mid-2022 contributed to the reduction. The Corporation is more than halfway to achieving its target to reduce greenhouse gas ("GHG") emissions 50% by 2030, and remains on track to reduce GHG emissions 75% by 2035. Upon achieving these targets, 99% of the Corporation's assets will be focused on energy delivery and renewable, carbon-free generation. Additionally, in 2022, Fortis established a 2050 net-zero direct GHG emissions target, reinforcing the Corporation's commitment to long-term decarbonization, while preserving customer reliability and affordability.

During the year, Fortis released its inaugural Task Force for Climate-Related Financial Disclosures ("TCFD") and Climate Assessment Report and its 2022 Sustainability Report. The TCFD and Climate Assessment Report advanced the Corporation's commitment as a TCFD supporter and included an analysis of risks and opportunities associated with four climate-related scenarios. The 2022 Sustainability Report fully aligned with applicable Sustainability Accounting Standards Board standards and included over 35 new key performance indicators. The report also provided an update on efforts to increase renewable generation sources, including new wind and solar generation at Tucson Electric Power.

Progress continued on the Wataynikaneyap Transmission Power Project during 2022. In August 2022, Phase 1 of the project was completed, energizing the 230 kV line from Dinorwic to Pickle Lake, Ontario. At the end of 2022, the project was 73% complete, with 700 kilometers of transmission line energized and three First Nation communities connected to the Ontario electric grid. Construction is expected to be completed in 2024.

Outlook

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. While energy price volatility, global supply chain constraints and persistent inflation are issues of potential concern that continue to evolve, the Corporation does not currently expect there to be a material impact on its operations or financial results in 2023.

The Corporation's $22.3 billion five-year capital plan is expected to increase midyear rate base from $34.1 billion in 2022 to $46.1 billion by 2027, translating into a five-year compound annual growth rate of 6.2%[3].

Beyond the five-year capital plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the Inflation Reduction Act of 2022 and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and liquefied natural gas infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2027. This dividend growth guidance will also provide flexibility to fund more capital with internally-generated funds and is premised on the assumptions and material factors listed under "Forward-Looking Information".

About Fortis

Fortis is a well-diversified leader in the North American regulated electric and gas utility industry with 2022 revenue of $11 billion and total assets of $64 billion as at December 31, 2022. The Corporation's 9,200 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Forward-Looking Information

Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2023-2027, including cleaner energy investments; forecast rate base and rate base growth through 2027; targeted annual dividend growth through 2027; the expected sources of funding for the 2023-2027 capital plan; the nature, timing, benefits and expected costs of certain capital projects, including the Wataynikaneyap Transmission Power project, ITC's transmission projects associated with the MISO LRTP, renewable energy and storage investments in Arizona and the Caribbean, and investments in cleaner fuel solutions in British Columbia, and additional opportunities beyond the capital plan, including investments related to the Inflation Reduction Act of 2022, the MISO LRTP, climate adaptation and grid resiliency, and renewable gas solutions and liquefied natural gas infrastructure in British Columbia; the expected timing, outcome and impact of regulatory proceedings and decisions; the 2030 GHG emissions reduction target; the 2035 GHG emissions reduction target and projected asset mix; the 2050 net-zero direct GHG emissions target; the expectation that volatility in energy prices, global supply chain constraints and persistent inflation will not have a material impact on operations or financial results in 2023; the expectation that long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2027; and the expectation that the dividend growth guidance will provide flexibility to fund more capital internally.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: no material impact from volatility in energy prices, global supply chain constraints and persistent inflation; reasonable outcomes for regulatory proceedings and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project and financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar to Canadian dollar exchange rate; and the Board exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. For additional information with respect to certain risk factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information herein is given as of the date of this media release. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Teleconference to Discuss 2022 Annual Results

A teleconference and webcast will be held on February 10, 2023 at 8:30 a.m. (Eastern). David Hutchens, President and Chief Executive Officer and Jocelyn Perry, Executive Vice President and Chief Financial Officer, will discuss the Corporation's 2022 annual results.

Shareholders, analysts, members of the media and other interested parties in North America are invited to participate by calling 1.416.764.8658. International participants may participate by calling 1.888.886.7786. Please dial in 10 minutes prior to the start of the call. No passcode is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com. A replay of the teleconference will be available two hours after the conclusion of the call until March 10, 2023. Please call 1.416.764.8692 or 1.877.674.7070 and enter passcode 760995#.

Additional Information

This media release should be read in conjunction with the Corporation's Management Discussion and Analysis and Consolidated Financial Statements. This and additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

For more information, please contact:

Investor Enquiries:	**Media Enquiries:**
Ms. Stephanie Amaimo	Ms. Karen McCarthy
Vice President, Investor Relations	Vice President, Communications & Corporate Affairs
Fortis Inc.	Fortis Inc.
248.946.3572	709.737.5323
investorrelations@fortisinc.com	media@fortisinc.com

Management Discussion and Analysis

Contents

Dated February 9, 2023

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2022 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 42. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

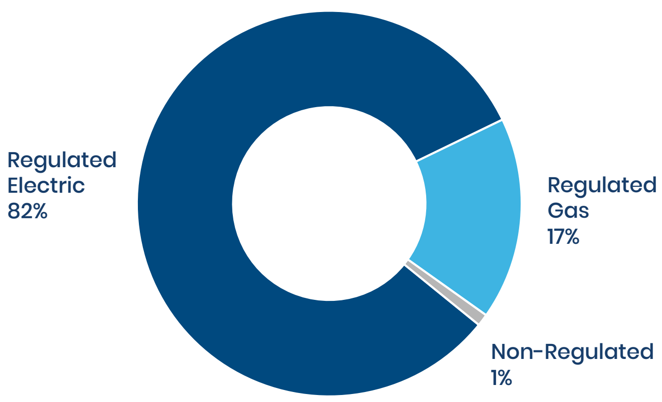
Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.30 and 1.25 for the years ended December 31, 2022 and 2021, respectively; (ii) 1.36 and 1.26 as at December 31, 2022 and 2021, respectively; (iii) average of 1.36 and 1.26 for the quarters ended December 31, 2022 and 2021, respectively; and (iv) 1.30 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 43.

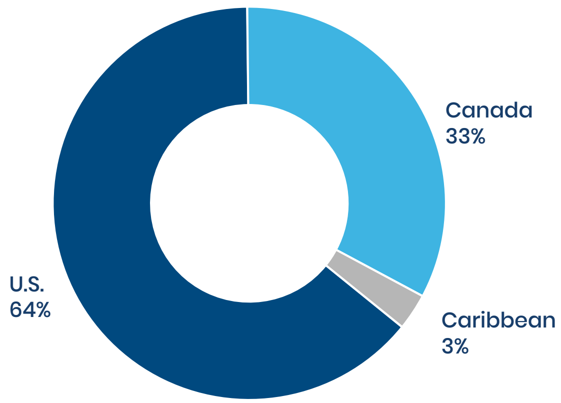
ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $11 billion in 2022 and total assets of $64 billion as at December 31, 2022.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,200 employees serve 3.4 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. As at December 31, 2022, 67% of the Corporation's assets were located outside Canada and 59% of 2022 revenue was derived from foreign operations.

TOTAL ASSETS AT DECEMBER 31, 2022





Fortis is principally an energy delivery company, with 93% of its assets related to transmission and distribution. The business is characterized by low-risk, stable and predictable earnings and cash flows. Earnings, EPS and TSR are the primary measures of financial performance.

Fortis' regulated utility businesses are: ITC (electric transmission - Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, and assets under construction in Wisconsin); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York State); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in the Wataynikaneyap Partnership (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

Non-regulated energy infrastructure consists of Fortis Belize (three hydroelectric generation facilities - Belize) and Aitken Creek (natural gas storage facility - British Columbia).

Fortis has a unique operating model with a small corporate office in St. John's, Newfoundland and Labrador and business units that operate on a substantially autonomous basis. Each utility has its own management team and board of directors, with most having a majority of independent board members, which provides effective oversight within the broad parameters of Fortis policies and best practices. Subsidiary autonomy supports constructive relationships with regulators, policy makers, customers and communities. Fortis believes this model enhances accountability, opportunity and performance across the Corporation's businesses, and positions Fortis well for future investment opportunities.

Fortis strives to provide safe, reliable and cost-effective energy service to customers while focusing on sustainability policies and practices. The Corporation has established delivering a cleaner energy future as its core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders through the execution of its Capital Plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2022 Annual Financial Statements.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2022**	2021	Variance
Common Equity Earnings			
Actual	**1,330**	1,231	99
Adjusted [(1)]	**1,329**	1,219	110
Basic EPS *($)*			
Actual	**2.78**	2.61	0.17
Adjusted [(1)]	**2.78**	2.59	0.19
Dividends			
Paid per common share *($)*	**2.17**	2.05	0.12
Actual Payout Ratio *(%)*	**78.1**	78.5	(0.4)
Adjusted Payout Ratio *(%)* [(1)]	**78.1**	79.2	(1.1)
Weighted average number of common shares outstanding *(# millions)*	**478.6**	470.9	7.7
Operating Cash Flow	**3,074**	2,907	167
Capital Expenditures [(1)]	**4,034**	3,564	470

(1) *See "Non-U.S. GAAP Financial Measures" on page 14*

Earnings and EPS

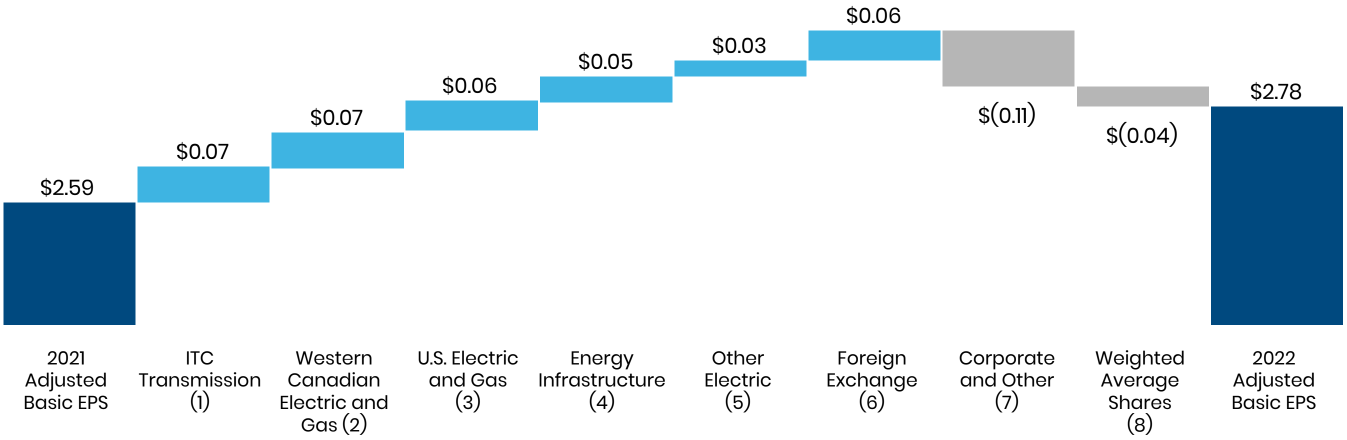
The Corporation reported Common Equity Earnings of $1.3 billion in 2022, or $2.78 per common share, compared to $1.2 billion, or $2.61 per common share in 2021. Our businesses performed well in 2022, delivering approximately 7% annual EPS growth. The increase was primarily driven by Rate Base growth across our utilities. The increase in earnings was also due to: (i) higher retail and wholesale electricity sales, as well as transmission revenue in Arizona; (ii) higher margins on gas sold and the mark-to-market accounting of natural gas derivatives at Aitken Creek; and (iii) the impact of new customer rates at Central Hudson. The translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results, with these impacts exceeding the related losses on derivatives associated with hedging activities.

Growth in earnings was tempered by certain discrete items at ITC including: (i) costs associated with the suspension of the Lake Erie Connector project; (ii) the revaluation of deferred income tax assets due to a reduction in the corporate income tax rate in the state of Iowa; and (iii) a favourable adjustment recognized in 2021 related to interest rate swaps. Losses on investments that support retirement benefits at UNS Energy and ITC, higher operating costs at Central Hudson related to the implementation of a new CIS, and higher corporate costs also tempered results.

In addition to the above-noted items impacting earnings, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Year over year, Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $110 million and $0.19, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 14 for a reconciliation of these measures. The changes in Adjusted Basic EPS are illustrated in the chart below.

CHANGES IN ADJUSTED BASIC EPS



(1) *Reflects Rate Base growth and lower non-recoverable stock-based compensation costs, partially offset by a favourable adjustment related to interest rate swaps in 2021, losses on investments that support retirement benefits and higher holding company finance costs*

(2) *Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, partially offset by an increase in operating expenses and a higher effective income tax rate at FortisAlberta*

(3) *Includes UNS Energy and Central Hudson. Reflects higher earnings at UNS Energy, due to higher retail and wholesale electricity sales, as well as transmission revenue, partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates, higher operating expenses, and losses on certain investments that support retirement benefits. Also reflects higher earnings at Central Hudson, driven by new customer rates due to the conclusion of the general rate application in 2021, and the impact of unfavourable regulatory deferrals recorded in 2021, partially offset by higher operating expenses associated with the implementation of a new CIS and non-recoverable finance costs*

(4) *Includes higher margins on gas sold at Aitken Creek, reflecting market conditions, and higher hydroelectric production in Belize associated with rainfall levels*

(5) *Primarily reflects Rate Base growth and higher electricity sales*

(6) *Average foreign exchange rate of 1.30 in 2022 compared to 1.25 in 2021*

(7) *Primarily reflects market conditions, including losses on total return swaps and foreign exchange contracts and higher finance costs, as well as lower income tax recovery*

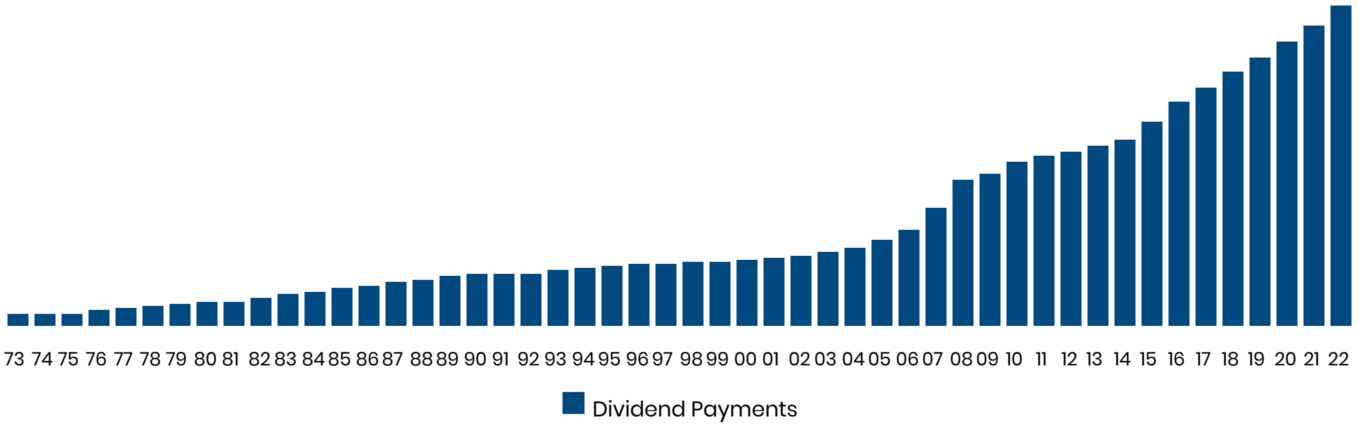
(8) *Weighted average shares of 478.6 million in 2022 compared to 470.9 million in 2021*

Dividends

Fortis paid a dividend of $0.565 per common share in the fourth quarter of 2022, up 5.6% from $0.535 paid in each of the previous four quarters. This marked the Corporation's 49th consecutive year of dividend increases. The Actual Payout Ratio was 78% in 2022 and an average of 68% over the five-year period of 2018 through 2022.

Fortis is targeting annual dividend growth of approximately 4-6% through 2027. See "Outlook" on page 41.

49 YEARS OF CONSECUTIVE DIVIDEND INCREASES



Growth in dividends and changes in the market price of the Corporation's common shares have yielded the following TSR.

TSR [1] *(%)*	**1-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**(7.9)**	**7.2**	**8.7**	**11.3**

[1] *Annualized TSR per Bloomberg, as at December 31, 2022*

Operating Cash Flow

The $167 million increase in Operating Cash Flow was due to: (i) higher cash earnings, reflecting Rate Base growth and higher retail and long-term wholesale electricity sales, as well as transmission revenue, in Arizona; (ii) collateral deposits received at UNS Energy related to derivative energy contracts; (iii) proceeds received at ITC upon the settlement of interest rate swaps; and (iv) the higher U.S.-to-Canadian dollar exchange rate. The timing of flow-through of costs in customer rates also favourably impacted Operating Cash Flow. The increase was partially offset by higher gas inventory levels in British Columbia, as well as storm restoration costs incurred in 2022, to be recovered in future customer rates, and higher accounts receivable at Central Hudson.

Capital Expenditures

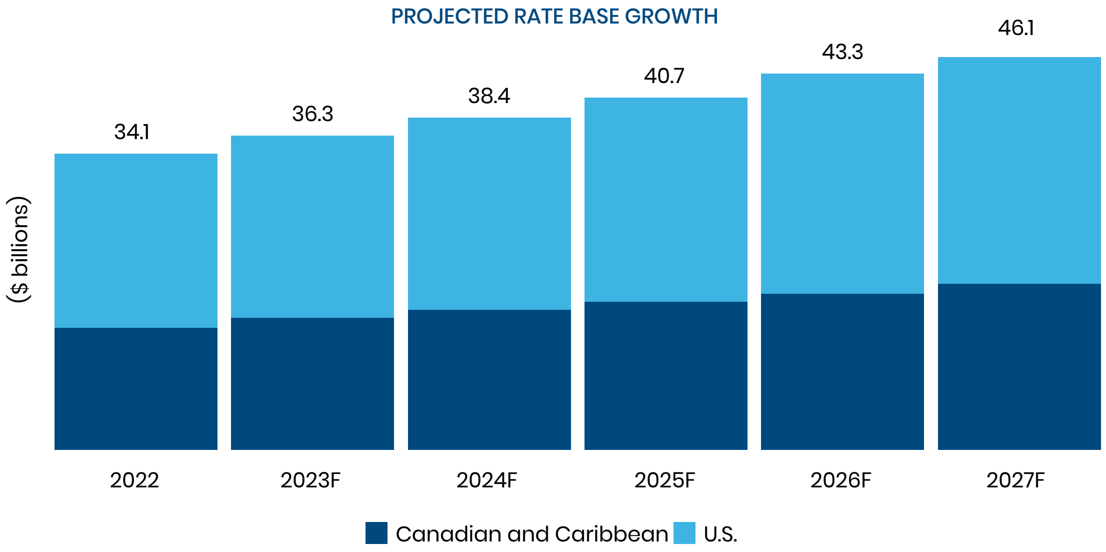
Capital Expenditures were $4.0 billion, consistent with the 2022 Capital Plan and $0.5 billion higher than 2021. The increase over 2021 was primarily due to continued investment in various smaller transmission and distribution projects at the Corporation's regulated utilities, as well as the impact of the higher average foreign exchange rate.

The Corporation's 2023-2027 Capital Plan of $22.3 billion is the largest in the Corporation’s history and is $2.3 billion higher than the previous five-year plan. The increase is driven by organic growth, largely reflecting regional transmission projects associated with the MISO LRTP at ITC, additional cleaner energy investments in Arizona to support TEP's planned exit from coal by 2032, and enhancements to distribution infrastructure reliability and capacity, as well as investments to support customer growth, across the Corporation's regulated utilities. Approximately $500 million of the increase is driven by a higher assumed U.S.-to-Canadian dollar exchange rate over the five-year period. See "Capital Plan" on page 21 for further information.

Funding of the Capital Plan is expected to be primarily through Operating Cash Flow, debt issued at the regulated utilities and common equity from the Corporation's DRIP.

The five-year Capital Plan is expected to increase midyear Rate Base from $34.1 billion in 2022 to $46.1 billion by 2027, representing a five-year CAGR of 6.2%.

Capital Expenditures and Capital Plan reflect Non-U.S. GAAP financial measures. Refer to "Non-U.S. GAAP Financial Measures" on page 14 and "Capital Plan" on page 21.



Beyond the five-year Capital Plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the IRA and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American energy industry's transformation is accelerating rapidly, driven by the impacts of climate change, as well as the need for a cleaner energy future and innovation. There is a growing need for the development of cleaner energy sources and the deployment of energy conservation measures to preserve the planet for future generations. The goal of carbon emissions reduction, and associated advancements in technology, have attracted interest from investors and customers. Electric transmission is seen as a critical enabler of large-scale renewable generation. Natural gas also continues to be an important part of the energy mix, as supplemental generation to the intermittent nature of renewables, and as a cost-effective heating source. Longer term, advancements in the use of hydrogen and RNG will further contribute to carbon reduction. Each of these factors, as well as the increasing affordability of cleaner energy, is driving significant investment opportunity in the utility sector.

Energy policies at the federal, state, and provincial levels reflect the rising focus on climate change, with clean energy and carbon reduction goals and initiatives at the forefront. In the U.S., the IRA has been passed into law and includes, among other items, incentives and clean energy tax credits encouraging investments in clean energy, energy storage, electric vehicles and manufacturing, all to support a targeted 40% reduction in carbon emissions by 2030. With states and provinces also setting ambitious carbon reduction targets, the regulatory and compliance environment continues to evolve and become increasingly complex. These changes are creating opportunities to expand investment in new, renewable generation sources, as well as transmission infrastructure to connect renewable energy sources to the grid. In addition to growth of renewable generation, investment opportunities in energy storage technology are also being created. The electrification of the transportation sector is gaining momentum and represents a significant opportunity to reduce carbon emissions while increasing the output and efficiency of the grid. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities which will drive significant investment.

New technology is stimulating change across all of the Corporation's service territories. Energy delivery systems are becoming more intelligent, with upgraded advanced meters, additional grid automation, high-speed private communications networks, and more capable operational technology, providing utilities with detailed usage data and predictive maintenance information to improve cost efficiency and safety. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have options to manage energy usage and access to more affordable distributed generation. Grid resilience is growing in importance with the increasing frequency and intensity of weather events such as hurricanes, wildfires, floods and storms. With electricity expected to represent a larger portion of society's energy mix, investments in grid hardening and resiliency are necessary to improve the grid's ability to withstand and recover from these climate events.

Fortis' culture of innovation underlies a continuous drive to find a better way to safely, reliably and affordably deliver the energy and services that customers need, and the choice and control they increasingly seek. Fortis is a partner in the Energy Impact Partners utility coalition, which is a strategic private equity fund that invests in emerging technologies, products, services and business models that are transforming the industry. The Corporation is also involved in the Low Carbon Resources Initiative, a collaboration between EPRI and GTI Energy, along with major North American utilities, to develop and demonstrate the low- and zero-carbon energy technologies needed to enable pathways to economy-wide decarbonization. In 2022, Fortis also joined EPRI's Climate READi, an initiative involving major North American utilities, regulators, policy makers, and other stakeholders focused on developing an industry-wide best practice framework for managing physical climate risk.

Meaningful customer engagement is important for utilities as customer expectations change. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized self-service offerings and more real-time, digital communication. Fortis' utilities are enhancing customer information systems and digital technologies to improve customer service.

On the security front, with the advent of new and increasing cyber threats to our information and operational technology systems, increased focus and investment on protection and response to these cyber events is an ongoing priority. Upgrades to the physical security environment is also required to keep pace with evolving challenges. All these technological advancements and challenges offer strategic investment opportunities for improving and expanding customer service and enhancing security.

The Corporation's culture and decentralized structure support the efforts required to meet changing customer expectations. Each of our utilities work constructively with regulators and all stakeholders on policy, energy and service solutions, and are an integral partner in all the communities they serve. Fortis is committed to be an industry leader in the clean energy transition.

FOCUS ON SUSTAINABILITY

Fortis is dedicated to operating in an environmentally and socially responsible manner in the interests of all of its stakeholders. Fortis believes that focusing on the responsible and sustainable management of its businesses is good for employees, customers, communities and the planet, but also, importantly, shareholders. Oversight and accountability for sustainability are established at the most senior levels of the Corporation and its operating subsidiaries. At Fortis, the Board has overall responsibility for sustainability. However, primary oversight of the issues, policies and practices pertaining to sustainability has been delegated to the governance and sustainability committee of the Board, reflecting sustainability's important role in the Corporation's strategy and management of risk.

Key aspects of Fortis' sustainability program and practices are outlined below.

Climate Change and Environmental Matters

Fortis is primarily an energy delivery company with 93% of its assets related to transmission and distribution. The focus for Fortis is the delivery of cleaner energy to its customers and this limits the impact of the Corporation's utilities on the environment when compared to more generation-intensive businesses. Fortis has a relatively small amount of fossil-fuel generation in its portfolio and has a plan to transition to more renewable sources of energy for its customers.

The Corporation's direct GHG emissions come primarily from its generation assets, which largely consist of fossil fuel-based generation at TEP, representing 4% of the Corporation's total assets. Fortis continues to build on its low emissions profile, and in May 2022, set a 2050 net-zero direct GHG emissions target. This goal is in addition to the Corporation's interim targets to reduce GHG emissions 50% by 2030 and 75% by 2035 from a 2019 base year. Fortis expects to achieve both interim targets without the use of carbon offsets, primarily through delivering on TEP's plan to reduce carbon emissions, as well as clean energy initiatives across the Corporation's other utilities.

Consistent with our interim targets and pathway to net-zero, in June 2022, TEP retired 170-MW of coal-fired generation through the planned closure of San Juan. Fortis has made significant progress on its emissions reduction targets. Through 2022, the Corporation's Scope 1 emissions were 28% lower compared to 2019 levels, equivalent to taking approximately 760,000 vehicles off the road in one year.

Beyond 2035, most of the Corporation's Scope 1 emissions are expected to relate to natural gas generation at TEP. To reach net-zero by 2050, TEP will focus on developing and adopting new technologies, improving the efficiency of natural gas units, utilizing lower-carbon fuels and preparing its generating units for future hydrogen injection. Reliability and affordability will remain key priorities as Fortis works to meet its emissions reduction targets.

The Corporation made progress on its commitment as a TCFD supporter in March 2022, with the release of its first TCFD and Climate Assessment Report, which included an analysis of four climate-related scenarios and associated risks and opportunities. This report provides information on Fortis' strategy and actions to address climate change, physical and transition risks, and business opportunities including investments in resilient and adaptable infrastructure. In July 2022, Fortis released its 2022 Sustainability Report, highlighting progress on a number of sustainability priorities, including adding more renewable energy, reducing GHG emissions and improving diversity. The report also provided enhanced information on the Corporation's sustainability strategy, significantly expanded the scope of key performance indicators, and was fully aligned with applicable Sustainability Accounting Standards Board standards.

In 2022, over $600 million in Capital Expenditures were focused on the delivery of cleaner energy to customers. In the development of the Corporation's five-year Capital Plan, each of the utilities considered the investment required to deliver cleaner energy to customers, strengthen infrastructure, and improve network resiliency to deal with the expected impacts of climate change on utility infrastructure. Fortis' 2023-2027 Capital Plan includes cleaner energy investments of $5.9 billion, with investments focused on connecting renewables to the grid, renewable and storage investments, and cleaner fuel solutions. Additional information can be found in the "Capital Plan" section on page 21. In support of the capital program, during 2022, Fortis amended its unsecured $1.3 billion revolving term committed credit facility agreement to include the establishment of a sustainability-linked loan structure based on the Corporation's achievement of targets related to diversity on the Board and reduction of Scope 1 GHG emissions for 2022 through 2025.

The Corporation's environmental statement sets out its commitment to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems, seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources. Each operating subsidiary has extensive environmental compliance programs aligned with the ISO 14001 standard, regularly reviews its environmental management systems and protocols, strives for continual performance improvement and sets and reviews its own environmental objectives, targets and programs.

Safety and Reliability

Fortis is an industry leader in safety and reliability, with the Corporation consistently performing above industry averages. Fortis leverages its unique operating model and utility experience to deliver safe and reliable service to its customers and the communities it serves. Senior operational executives from all Fortis utilities meet regularly to share best practices and identify opportunities for collaboration on a range of operational areas including health and safety.

All contractors are required to share our commitment to conduct work in a safe manner. Contractors must demonstrate a strong safety program with a high level of training centered around risk management. Historical safety performance is a consideration when selecting successful contractors.

Engaging with Stakeholders and Communities

Fortis' utilities work closely with their customers and communities to drive enhancements and improve the overall customer service experience. Customer satisfaction targets are established and customer service surveys are completed regularly focusing on customer satisfaction, reliability and accuracy of billing and metering, contact center services and reliability of energy supply.

Customer affordability is a key priority for Fortis. Historically, Fortis utilities have managed annual increases in controllable operating costs per customer to below inflation. In addition, our utilities work to ensure customers are aware of bill payment options, external government payment assistance programs, as well as home energy efficiency programs and rebates.

Fortis and its utilities work with a number of Indigenous groups, with the goal of developing long-term partnerships and creating economic opportunities. The Wataynikaneyap Power Transmission project is an 1,800 kilometer transmission line that will connect 17 First Nations communities to the Ontario power grid for the first time. These communities currently have inefficient and unreliable access to electricity based on diesel generation, compromising their economic and social well-being and limiting their opportunities for growth. The project is majority-owned by 24 First Nations, while Fortis has a 39% ownership interest and acts as project manager. Additional information can be found in the "Capital Plan" section on page 21.

Fortis and its utilities consistently look for opportunities for growth, innovation and energy efficiency in the communities they serve. Regular community engagement includes donations to local charities, partnerships with educational institutions, and participation on local boards, which enables Fortis and its utilities to serve as meaningful contributors to their local communities. In 2022, the Fortis group of companies contributed $9.7 million to the communities they serve.

Cybersecurity

Fortis' CRMP aims to continually improve information sharing and the culture of security. Fortis has an enterprise-wide CRMP that allows for the identification, measurement, monitoring and management of cybersecurity risks. Further, the Corporation and each of the utilities continually consider investments required in security, in both the corporate and grid environments, during the development of the five-year Capital Plan. Physical and cyber security leaders share best practices in areas such as threat monitoring, protecting customer information and risk management. The group also conducts training exercises to test systems and identify opportunities to improve. Oversight of cybersecurity is the responsibility of Fortis' Vice President, Chief Information Officer as well as the respective boards and executive committees at Fortis and at each utility. The Fortis group of companies have not had any reportable cybersecurity breaches since we began reporting this performance indicator in 2018.

Human Capital Management

Fortis values its 9,200 employees and recognizes that success is dependent on a strong workforce which is safe, supported and empowered. Fortis and its utilities have compensation and benefit programs designed to attract and retain talent. Fortis believes that the foundation for a healthy work environment starts with leadership from the most senior levels of the organization and must be driven by clearly articulated values that are understood and practiced at all levels of the organization.

Fortis has a longstanding corporate-wide talent management strategy that enhances our ability to identify, mentor and develop current executives and employees for more senior positions. The Corporation seeks to continually enhance its talent management strategy. In 2022, it completed the inaugural year of a new leadership training program for high-potential employees across the organization that provides substantive training, mentoring opportunities and exposure to management. This approach supports talent development and ensures there is a pipeline of qualified talent, preparing the Corporation and its utilities for an orderly succession of critical roles.

Our utilities strive to maintain good employee and labour relations and regular communications and collaboration between union and management leaders. Approximately 50% of the employees across our group of companies are represented by a labour union.

Governance & Executive Compensation

The Fortis Code of Conduct is guided by the Corporation's purpose and values and sets out standards for the ethical conduct of its directors, officers, employees, consultants, contractors and representatives. The core principles of the Code of Conduct apply across the organization, with each operating subsidiary adopting its own substantially similar Code. Fortis and its utilities hold regular Code of Conduct employee training and all Fortis employees and Board members annually certify compliance.

The Code of Conduct is supported by other policies that outline the actions and behaviours expected from management and employees, including the Anti-Corruption Policy and Respectful Workplace Policy. All Fortis operating subsidiaries have policies in place that uphold the Corporation's values as contained in these policies and demonstrate their commitment to ensuring equal opportunity and providing safe, respectful work environments.

Fortis and each of its operating subsidiaries have a Speak Up Policy to support and facilitate the anonymous reporting of conduct that may breach the Code of Conduct or other workplace policies.

Achieving Fortis' sustainability objectives is a focus for the Board and forms a component of executive compensation. Sustainability-related performance measures including ESG leadership, carbon reduction, safety and reliability, and diversity, equity and inclusion are embedded in the Corporation's executive compensation program.

Diversity, Equity and Inclusion

The Corporation's Board and Executive Diversity Policy describes the principles and objectives for diversity among the Board and executive leadership, including a commitment to maintain a Board where at least 40% of independent directors are women. As of December 31, 2022, 54% of Board members were women, 42% of Fortis' executives were women and 73% of Fortis utilities had either a female president or female board chair. The Corporation also committed to have at least two Board members who identify as a visible minority or Indigenous person by 2023, and achieved this objective as of December 31, 2022.

Advancing diversity, equity and inclusion is a priority at Fortis. The Corporation adopted an Inclusion and Diversity Commitment that applies to all employees of Fortis and its operating subsidiaries. The commitment is supported by a framework built upon three pillars - talent, culture and community. A Diversity, Equity and Inclusion Advisory Council with diverse, senior level representation from across the Fortis organization guides the inclusion and diversity strategy and its implementation.

OPERATING RESULTS

			Variance	
($ millions)	**2022**	2021	FX	Other
Revenue	**11,043**	9,448	206	1,389
Energy supply costs	**3,952**	2,951	55	946
Operating expenses	**2,683**	2,523	61	99
Depreciation and amortization	**1,668**	1,505	30	133
Other income, net	**165**	173	4	(12)
Finance charges	**1,102**	1,003	22	77
Income tax expense	**289**	234	7	48
Net earnings	**1,514**	1,405	35	74
Net earnings attributable to:				
Non-controlling interests	**120**	111	4	5
Preference equity shareholders	**64**	63	—	1
Common equity shareholders	**1,330**	1,231	31	68
Net Earnings	**1,514**	1,405	35	74

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) higher flow-through costs in customer rates, driven by higher commodity prices; (ii) Rate Base growth; and (iii) higher retail and wholesale electricity sales, as well as transmission revenue, at UNS Energy, partially offset by the normal operation of regulatory deferrals at FortisBC Energy.

Energy Supply Costs

The increase in energy supply costs, net of foreign exchange, was due primarily to higher commodity costs reflecting increases in pricing and volumes.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to general inflationary and employee-related cost increases, as well as the implementation of a new CIS at Central Hudson, partially offset by lower stock-based compensation costs.

Depreciation and Amortization

The increase in depreciation and amortization, net of foreign exchange, was due to continued investment in energy infrastructure at the Corporation's regulated utilities, as well as new depreciation rates, recoverable in customer rates, at ITC effective January 1, 2022.

Other Income, Net

The decrease in other income, net of foreign exchange, was due primarily to losses on total return swaps and foreign exchange contracts in the Corporate and Other segment, as well as losses on investments that support retirement benefits at UNS Energy and ITC. The decrease was largely offset by an increase in the non-service component of benefit costs.

Finance Charges

The increase in finance charges, net of foreign exchange, was due to higher debt levels to support the Corporation's Capital Plan, as well as higher interest rates impacting variable-rate debt and new debt issuances.

Income Tax Expense

The increase in income tax expense, net of foreign exchange, was driven by: (i) higher earnings before taxes; (ii) the revaluation of deferred income tax assets resulting from a reduction in the corporate income tax rate in the state of Iowa; and (iii) a lower income tax recovery in the Corporate & Other segment, including a lower benefit associated with filing a consolidated U.S. tax return and the timing of true-ups to the income tax provision to reflect tax filings.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 3.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

			Variance	
($ millions)	**2022**	2021	FX (1)	Other
Regulated Utilities				
ITC	**454**	426	16	12
UNS Energy	**328**	292	12	24
Central Hudson	**103**	93	3	7
FortisBC Energy	**203**	185	—	18
FortisAlberta	**151**	141	—	10
FortisBC Electric	**64**	59	—	5
Other Electric (2)	**134**	118	2	14
	1,437	1,314	33	90
Non-Regulated				
Energy Infrastructure (3)	**72**	38	—	34
Corporate and Other (4)	**(179)**	(121)	(2)	(56)
Common Equity Earnings	**1,330**	1,231	31	68

(1) *The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and Fortis Belize is the U.S. dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the U.S. dollar at BZ$2.00=US$1.00. The Corporate and Other segment includes certain transactions denominated in U.S. dollars*

(2) *Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Wataynikaneyap Partnership; Caribbean Utilities; FortisTCI; and Belize Electricity*

(3) *Primarily consists of long-term contracted generation assets in Belize and Aitken Creek in British Columbia*

(4) *Includes Fortis net corporate expenses and non-regulated holding company expenses*

ITC

			Variance	
($ millions)	**2022**	2021	FX	Other
Revenue (1)	**1,906**	1,691	63	152
Earnings (1)	**454**	426	16	12

(1) *Revenue represents 100% of ITC. Earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflect consolidated purchase price accounting adjustments.*

Revenue

The increase in revenue, net of foreign exchange, was due primarily to higher recoverable depreciation expense, reflecting revised depreciation rates effective January 1, 2022, and Rate Base growth.

Earnings

The increase in earnings, net of foreign exchange, reflected Rate Base growth and lower non-recoverable stock-based compensation costs. Growth in earnings was tempered by certain discrete items including: (i) costs associated with the suspension of the Lake Erie Connector project; (ii) the revaluation of deferred income tax assets resulting from a reduction in the corporate income tax rate in the state of Iowa; and (iii) a favourable adjustment recognized in 2021 related to interest rate swaps. Losses on certain investments that support retirement benefits and higher holding company finance costs also unfavourably impacted results.

In July 2022, ITC suspended development activities and commercial negotiations relating to the $1.7 billion Lake Erie Connector project. ITC determined that there was no viable path to conclude certain key commercial negotiations and other requirements within the required timelines, in part due to macroeconomic conditions, including rising inflation, interest rates, and fluctuations in the U.S.-to-Canadian dollar foreign exchange rate. This project was never included in the Corporation's five-year Capital Plan.

UNS Energy

			Variance	
($ millions, except as indicated)	**2022**	2021	FX	Other
Retail electricity sales *(GWh)*	**10,658**	10,559	—	99
Wholesale electricity sales *(GWh)* [(1)]	**5,401**	6,283	—	(882)
Gas sales *(PJ)*	**16**	16	—	—
Revenue	**2,758**	2,334	93	331
Earnings	**328**	292	12	24

[(1)] *Primarily short-term wholesale sales*

Sales

The increase in retail electricity sales was due primarily to favourable weather as compared to 2021 and customer growth.

The decrease in wholesale electricity sales was driven by lower short-term wholesale electricity sales, partially offset by higher long-term wholesale electricity sales. Revenue from short-term wholesale electricity sales is primarily credited to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

Gas sales were consistent with 2021.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) the recovery of higher fuel and non-fuel costs through the normal operation of regulatory mechanisms; (ii) higher revenue from short-term wholesale electricity sales due to favourable pricing; (iii) higher long-term wholesale electricity sales; (iv) higher retail electricity sales, discussed above; and (v) higher transmission revenue. The increase was partially offset by lower short-term wholesale electricity sales.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to higher retail electricity sales, long-term wholesale electricity sales, and transmission revenue. The increase in earnings was partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates, higher operating expenses, and losses on certain investments that support retirement benefits.

Central Hudson

			Variance	
($ millions, except as indicated)	**2022**	2021	FX	Other
Electricity sales *(GWh)*	**5,002**	5,000	—	2
Gas sales *(PJ)*	**25**	23	—	2
Revenue	**1,325**	1,000	36	289
Earnings	**103**	93	3	7

Sales

Electricity sales were consistent with 2021.

The increase in gas sales was due to higher average consumption by residential, commercial and industrial customers due to colder temperatures.

Changes in electricity and gas sales at Central Hudson are subject to regulatory revenue decoupling mechanisms and, therefore, do not materially impact earnings.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) the flow through of higher energy supply costs driven by commodity prices; and (ii) an increase in gas and electricity delivery rates effective July 1, 2021 and July 1, 2022, reflecting a return on increased Rate Base assets and the recovery of higher operating and finance expenses, associated with the conclusion of Central Hudson's general rate application in 2021.

Earnings

The increase in earnings, net of foreign exchange, was due to new customer rates discussed above, and the impact of unfavourable regulatory deferrals recorded in 2021 associated with reliability performance targets. The increase was partially offset by higher operating expenses associated with the implementation of a new CIS, and higher non-recoverable finance costs.

FortisBC Energy

($ millions, except as indicated)	**2022**	2021	Variance
Gas sales *(PJ)*	**231**	228	3
Revenue	**2,084**	1,715	369
Earnings	**203**	185	18

Sales

The increase in gas sales was due primarily to higher average consumption by residential and commercial customers due to colder temperatures, partially offset by lower average consumption by transportation customers.

Revenue

The increase in revenue was due primarily to a higher cost of natural gas recovered from customers and Rate Base growth, partially offset by the normal operation of regulatory deferrals.

Earnings

The increase in earnings was due primarily to Rate Base growth.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

FortisAlberta

($ millions, except as indicated)	**2022**	2021	Variance
Electricity deliveries *(GWh)*	**16,923**	16,643	280
Revenue	**680**	644	36
Earnings	**151**	141	10

Deliveries

The increase in electricity deliveries was due to higher load from industrial customers, higher average consumption by commercial customers, and customer additions. The increase was partially offset by lower average consumption by residential customers due to milder weather in 2022 as compared to 2021.

As approximately 85% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries. Significant variations in weather conditions, however, can impact revenue and earnings.

Revenue

The increase in revenue was due to Rate Base growth.

Earnings

The increase in earnings was due to Rate Base growth, partially offset by higher operating expenses and a higher effective income tax rate.

FortisBC Electric

($ millions, except as indicated)	**2022**	2021	Variance
Electricity sales *(GWh)*	**3,542**	3,460	82
Revenue	**487**	468	19
Earnings	**64**	59	5

Sales

The increase in electricity sales was due primarily to higher average consumption by industrial customers.

Revenue

The increase in revenue was due to higher electricity sales, Rate Base growth, and higher surplus power sales, partially offset by the normal operation of regulatory deferrals.

Earnings

The increase in earnings was due primarily to Rate Base growth.

Due to regulatory deferral mechanisms, changes in consumption levels do not materially impact earnings.

Other Electric

			Variance	
($ millions, except as indicated)	**2022**	2021	FX	Other
Electricity sales *(GWh)*	**9,470**	9,266	—	204
Revenue	**1,652**	1,498	14	140
Earnings	**134**	118	2	14

Sales

The increase in electricity sales was due to higher average consumption by residential and commercial customers in Eastern Canada, as well as higher sales in the Caribbean, due to increased tourism-related activities.

Revenue

The increase in revenue, net of foreign exchange, was due to the flow through of higher energy supply costs, higher electricity sales and Rate Base growth, as well as the normal operation of regulatory mechanisms at Newfoundland Power.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth and higher electricity sales.

Energy Infrastructure

($ millions, except as indicated)	**2022**	2021	Variance
Electricity sales *(GWh)*	**225**	147	78
Revenue	**151**	98	53
Earnings	**72**	38	34

Sales

The increase in electricity sales reflected an increase in hydroelectric production in Belize associated with higher rainfall levels.

Revenue and Earnings

Revenue and earnings were favourably impacted by the mark-to-market accounting of natural gas derivatives at Aitken Creek, which resulted in unrealized gains of $20 million in 2022 compared to $12 million in 2021.

Excluding the impact of mark-to-market accounting, revenue and earnings increased by $43 million and $26 million, respectively. The increases were driven by Aitken Creek due to higher margins on gas sold, reflecting market conditions, as well as losses realized on natural gas contracts in 2021, as certain contracts were settled that year in consideration of favourable forward curves. Higher hydroelectric production in Belize also contributed to the increases in revenue and earnings.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to materially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resultant earnings volatility can be significant.

Corporate and Other

($ millions)	2022	2021	Variance FX	Variance Other
Net expenses	**(179)**	(121)	(2)	(56)

The increase in net expenses, net of foreign exchange, largely reflected market conditions, including losses on total return swaps and foreign exchange contracts, as well as higher finance costs. A lower income tax recovery also contributed to results. The increase in net expenses was partially offset by a reduction in operating expenses reflecting lower stock-based compensation costs.

Results for the Corporate and Other segment include the impact of hedging activities associated with share-based compensation and foreign exchange, and therefore can fluctuate depending on market conditions. On a consolidated basis, the overall earnings impact was favourable as lower stock based compensation costs and the translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate was greater than losses on derivatives associated with hedging activities.

NON-U.S. GAAP FINANCIAL MEASURES

Adjusted Common Equity Earnings, Adjusted Basic EPS, Adjusted Payout Ratio and Capital Expenditures are Non-U.S. GAAP Financial Measures and may not be comparable with similar measures used by other entities. They are presented because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects.

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable U.S. GAAP measures to Adjusted Common Equity Earnings and Adjusted Basic EPS, respectively. The Actual Payout Ratio calculated using Common Equity Earnings is the most comparable U.S. GAAP measure to the Adjusted Payout Ratio. These adjusted measures reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results.

Capital Expenditures include additions to property, plant and equipment and additions to intangible assets, as shown on the consolidated statements of cash flows. It also includes Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, consistent with Fortis' evaluation of operating results and its role as project manager during the construction of this Major Capital Project.

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	2022	2021	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,330**	1,231	99
Adjusting items:			
Unrealized gain on mark-to-market of derivatives (1)	**(20)**	(12)	(8)
Lake Erie Connector project suspension costs (2)	**10**	—	10
Revaluation of deferred income tax assets (3)	**9**	—	9
Adjusted Common Equity Earnings	**1,329**	1,219	110
Adjusted Basic EPS (4) ($)	**2.78**	2.59	0.19
Adjusted Payout Ratio (5) (%)	**78.1**	79.2	(1.1)
Capital Expenditures			
Additions to property, plant and equipment	**3,587**	3,189	398
Additions to intangible assets	**278**	197	81
Adjusting item:			
Wataynikaneyap Transmission Power Project (6)	**169**	178	(9)
Capital Expenditures	**4,034**	3,564	470

(1) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $7 million in 2022 (2021 - $5 million), included in the Energy Infrastructure segment*

(2) *Represents costs incurred upon the suspension of the Lake Erie Connector project, net of income tax recovery of $4 million, included in the ITC segment*

(3) *Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa, included in the ITC segment*

(4) *Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 478.6 million in 2022 (2021 - 470.9 million)*

(5) *Calculated using dividends paid per common share of $2.17 in 2022 (2021 - $2.05) divided by Adjusted Basic EPS*

(6) *Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric segment*

REGULATORY HIGHLIGHTS

General

The earnings of the Corporation's regulated utilities are determined under COS regulation, with some using PBR mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved Rate Base. PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved ROE or ROA may depend on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

Transmission operations in the U.S. are regulated federally by FERC. Remaining utility operations in the U.S. and Canada are regulated by state or provincial regulators. Utility operations in the Caribbean are regulated by governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2022 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 25.

Significant Regulatory Developments

ITC

ITC Midwest Capital Structure Complaint: In May 2022, ICAT filed a complaint with FERC under Section 206 of the Federal Power Act requesting that ITC Midwest's common equity component of capital structure be reduced from 60% to 53%. ICAT alleged that ITC Midwest does not meet FERC's three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In November 2022, FERC issued an order denying the complaint, and in December 2022, ICAT filed a request for rehearing with FERC. The Corporation continues to believe the complaint is without merit, and as at December 31, 2022, ITC Midwest has not recorded a regulatory liability related to the complaint.

MISO Base ROE: In August 2022, the D.C. Circuit Court issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the MISO region, including ITC. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect. The court has remanded the matter to FERC for further process, the timing and outcome of which is unknown. Although any potential impact to Fortis is uncertain, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

Transmission Incentives: In 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding is unknown.

UNS Energy

TEP General Rate Application: In June 2022, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2023 using a December 31, 2021 test year. The application reflects a US$136 million net increase in non-fuel and fuel-related revenue, as well as proposals to eliminate certain adjustor mechanisms, and modify an existing adjustor to provide more timely recovery of clean energy investments. The timing and outcome of this proceeding is unknown.

Central Hudson

CIS Implementation: In December 2022, the PSC released a report into the deployment by Central Hudson of its new CIS. The PSC also issued an Order to Commence Proceeding and Show Cause, which directed Central Hudson to explain why the PSC should not pursue civil or administrative penalties or initiate a proceeding to review the prudence of the CIS implementation costs. Central Hudson was also required to submit a plan to eliminate bi-monthly bill estimates and to evaluate the customer impacts of such a change. Central Hudson's response was filed in January 2023. The timing and outcome of this proceeding is unknown.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In 2021, the BCUC initiated a proceeding including a review of the common equity component of capital structure and the allowed ROE. FortisBC filed a final argument with the BCUC in December 2022 and the proceeding remains ongoing, with a decision expected in the second quarter of 2023.

FortisAlberta

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for Alberta regulated utilities for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. In March 2022, the AUC issued a decision extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. The GCOC proceeding for 2024 and beyond remains ongoing, and a decision is expected in the third quarter of 2023.

2023 COS Application: In July 2022, the AUC issued a decision largely accepting the forecast requested in FortisAlberta's COS application. The associated compliance filing, including the updated 2023 revenue requirement, was approved by the AUC in December 2022.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta is participating in this proceeding and a decision from the AUC is expected in 2023.

REA Cost Recovery: In 2021, the AUC determined that costs attributable to REAs, approximating $10 million annually, can no longer be recovered from FortisAlberta's rate payers, effective January 1, 2023. FortisAlberta filed an appeal with the Alberta Court of Appeal, asserting that the AUC erred in preventing the company from recovering these costs from its own rate payers to the extent that such costs cannot be recovered directly from REAs. The appeal was heard in December 2022, and a decision from the Court is expected in first quarter of 2023.

FINANCIAL POSITION

Significant Changes between December 31, 2022 and 2021

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Accounts receivable and other current assets	**56**	**772**	Due to: (i) the flow through of higher energy supply costs; (ii) an increase in the fair value of energy contracts at UNS Energy; (iii) higher wholesale electricity revenue at UNS Energy; and (iv) slower collections at Central Hudson.
Inventories	**26**	**157**	Reflects an increase in the cost and amount of natural gas in storage.
Other assets	**57**	**201**	Reflects an increase in the fair value of energy contracts at UNS Energy and equity contributions associated with the Wataynikaneyap Power project.
Regulatory assets (current and long-term)	**87**	**333**	Due to: (i) the normal operation of rate stabilization accounts, reflecting the flow through of higher commodity costs; (ii) the deferral of incremental restoration costs associated with significant weather events; (iii) unrealized losses on natural gas derivatives at FortisBC Energy; and (iv) higher energy management costs to be recovered in customer rates. The increase was partially offset by the normal operation of employee future benefit deferrals.
Property, plant and equipment, net	**1,722**	**2,125**	Due to capital expenditures, partially offset by depreciation.
Intangible assets, net	**71**	**134**	Largely reflects investment in land rights and computer software at UNS Energy, partially offset by amortization.
Goodwill	**744**	**—**	
Accounts payable & other current liabilities	**90**	**628**	Due to: (i) higher energy supply costs; (ii) an increase in trade accounts payable, reflecting the timing of payments; (iii) higher income taxes payable; and (iv) an decrease in the fair value of natural gas derivatives at FortisBC Energy.
Other liabilities	**57**	**(320)**	Reflects a decrease in employee future benefit liabilities driven by higher discount rates.
Regulatory liabilities (current and long-term)	**157**	**536**	Reflects unrealized gains on energy contracts at UNS Energy, which are utilized to reduce exposure to changes in energy prices, and the normal operation of rate stabilization accounts and employee future benefit and future cost of removal deferrals.

Significant Changes between December 31, 2022 and 2021

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Deferred income tax liabilities	**154**	**279**	Due to higher temporary differences associated with ongoing capital investment.
Long-term debt (including current portion)	**1,190**	**1,887**	Reflects debt issuances partially offset by debt repayments, and higher borrowings under committed credit facilities, in support of the Corporation's Capital Plan.
Shareholders' equity	**983**	**759**	Due primarily to: (i) Common Equity Earnings for 2022, less dividends declared on common shares; and (ii) the issuance of common shares, largely under the DRIP.
Non-controlling interests	**117**	**67**	Reflects net earnings for 2022, less dividends declared by the Corporation's subsidiaries, attributable to non-controlling interests.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will be paid from Operating Cash Flow, with varying levels of residual cash flow available for capital expenditures and/or dividend payments to Fortis. Remaining capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's committed credit facility, the operation of the DRIP and issuances of common shares, preference equity and long-term debt. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. Both Fortis and its subsidiaries initially borrow through their committed credit facilities and periodically replace these borrowings with long-term financing. Financing needs also arise to refinance maturing debt.

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the total revolving credit facilities. Approximately $5.6 billion of the total credit facilities are committed with maturities ranging from 2023 through 2027. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2022**	2021
Total credit facilities [(1)]	3,795	2,055	**5,850**	4,846
Credit facilities utilized:				
Short-term borrowings	(253)	—	**(253)**	(247)
Long-term debt (including current portion)	(922)	(735)	**(1,657)**	(1,305)
Letters of credit outstanding	(76)	(52)	**(128)**	(115)
Credit facilities unutilized	2,544	1,268	**3,812**	3,179

(1) *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2022 Annual Financial Statements*

In 2022, Central Hudson increased its available credit facilities from US$230 million to US$320 million.

In May 2022, the Corporation amended its unsecured $1.3 billion revolving term committed credit facility agreement to extend the maturity to July 2027, and to establish a sustainability-linked loan structure based on the Corporation's achievement of targets for diversity on the Board and Scope 1 GHG emissions for 2022 through 2025. Maximum potential annual margin pricing adjustments are +/- 5 basis points and +/- 1 basis point for drawn and undrawn funds, respectively.

Also in May 2022, the Corporation entered into an unsecured US$500 million non-revolving term credit facility. The facility has an initial one-year term, is repayable at any time without penalty, provides the Corporation with additional, cost effective short-term financing and liquidity, and enhances financial flexibility.

The Corporation's ability to service debt and pay dividends is dependent on the financial results of, and the related cash payments from, its subsidiaries. Certain regulated subsidiaries are subject to restrictions that limit their ability to distribute cash to Fortis, including restrictions by certain regulators limiting annual dividends and restrictions by certain lenders limiting debt to total capitalization. There are also practical limitations on using the net assets of the regulated subsidiaries to pay dividends, based on management's intent to maintain the subsidiaries' regulator-approved capital structures. Fortis does not expect that maintaining such capital structures will impact its ability to pay dividends in the foreseeable future.

As at December 31, 2022, consolidated fixed-term debt maturities/repayments are expected to average $1,437 million annually over the next five years and approximately 73% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In November 2022, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. As at December 31, 2022, $2.0 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity. This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2023.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2022 and are expected to remain compliant in 2023.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

($ millions)	**2022**	2021	Variance
Cash and cash equivalents, beginning of year	**131**	249	(118)
Cash from (used in):			
Operating activities	**3,074**	2,907	167
Investing activities	**(4,059)**	(3,488)	(571)
Financing activities	**1,035**	451	584
Effect of exchange rate changes on cash and cash equivalents	**28**	12	16
Cash and cash equivalents, end of year	**209**	131	78

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 5.

Investing Activities

The increase in cash used in investing activities reflects higher capital expenditures in 2022, as well as the higher U.S.-to-Canadian dollar exchange rate. See "Performance at a Glance - Capital Expenditures" on page 5 and "Capital Plan" on page 21. Planned equity contributions associated with the Wataynikaneyap Power project in 2022 also impacted the use of cash as compared to the prior year.

Financing Activities

Cash flow related to financing activities will fluctuate largely as a result of changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, which together impact the amount of funding required from debt and common equity issuances. See "Cash Flow Requirements" on page 17.

Debt Financing

Long-Term Debt Issuances

Year ended December 31, 2022	Month Issued	Interest Rate (%)	Maturity	**Amount** ($ millions)	Use of Proceeds
ITC					
Secured first mortgage bonds	January	2.93	2052	**US 150**	(1) (2) (3) (4)
Secured senior notes	May	3.05	2052	**US 75**	(1) (3) (4)
Unsecured senior notes	September	4.95 (5)	2027	**US 600**	(1) (4) (6)
Secured first mortgage bonds	October	3.87	2027	**US 75**	(2)
Secured first mortgage bonds	October	4.53	2052	**US 75**	(2)
UNS Energy					
Unsecured senior notes	February	3.25	2032	**US 325**	(4) (6)
Central Hudson					
Unsecured senior notes	January	2.37	2027	**US 50**	(4) (6)
Unsecured senior notes	January	2.59	2029	**US 60**	(4) (6)
Unsecured senior notes	September	5.07	2032	**US 100**	(1) (4)
Unsecured senior notes	September	5.42	2052	**US 10**	(1) (4)
FortisBC Energy					
Unsecured debentures	November	4.67	2052	**150**	(2)
FortisAlberta					
Senior unsecured debentures	May	4.62	2052	**125**	(1)
FortisBC Electric					
Unsecured debentures	March	4.16	2052	**100**	(1)
Newfoundland Power					
First mortgage sinking fund bonds	April	4.20	2052	**75**	(1) (4) (6)
Caribbean Utilities					
Unsecured senior notes	November	5.88	2052	**US 80**	(1) (3)
Fortis					
Unsecured senior notes	May	4.43 (7)	2029	**500**	(4) (8)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund or refinance, in part or in full, a portfolio of new and/or existing eligible green projects*
(3) *Fund capital expenditures*
(4) *General corporate purposes*
(5) *ITC entered into interest rate swaps which reduced the effective interest rate to 3.54%. See Note 25 to the 2022 Annual Financial Statements*
(6) *Repay maturing long-term debt*
(7) *The Corporation entered into cross-currency interest rate swaps to effectively convert the debt into US$391 million with an interest rate of 4.34%. See Note 25 to the 2022 Annual Financial Statements*
(8) *Fund the June 2022 redemption of the Corporation's $500 million, 2.85% senior unsecured notes due December 2023*

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31

($ millions, except as indicated)	**2022**	2021	Variance
Common shares issued:			
Cash (1)	**53**	60	(7)
Non-cash (2)	**366**	358	8
Total common shares issued	**419**	418	1
Number of common shares issued *(# millions)*	**7.4**	8.0	(0.6)
Common share dividends paid:			
Cash	**(673)**	(608)	(65)
Non-cash (3)	**(364)**	(356)	(8)
Total common share dividends paid	**(1,037)**	(964)	(73)
Dividends paid per common share *($)*	**2.17**	2.05	0.12

(1) *Includes common shares issued under stock option and employee share purchase plans*
(2) *Common shares issued under the DRIP and stock option plan*
(3) *Common share dividends reinvested under the DRIP*

On November 17, 2022 and February 9, 2023, Fortis declared a dividend of $0.565 per common share payable on March 1, 2023 and June 1, 2023, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

Contractual Obligations

Contractual Obligations

As at December 31, 2022

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [(1)]	**28,578**	2,481	1,434	518	2,434	1,977	19,734
Interest	**17,159**	1,105	1,056	1,020	988	908	12,082
Finance leases [(2)]	**1,177**	35	35	35	35	36	1,001
Other obligations [(3)]	**422**	116	86	77	30	29	84
Other commitments: [(4)]							
Gas and fuel purchase obligations	**5,720**	1,024	516	461	374	328	3,017
Waneta Expansion capacity agreement	**2,472**	54	55	56	58	59	2,190
Renewable power purchase agreements	**1,926**	131	131	131	131	130	1,272
Power purchase obligations	**1,691**	334	253	191	192	113	608
ITC easement agreement	**380**	14	14	14	14	14	310
Debt collection agreement	**106**	3	3	3	3	3	91
Renewable energy credit purchase agreements	**77**	18	14	7	7	6	25
Other	**132**	21	9	20	3	3	76
	59,840	5,336	3,606	2,533	4,269	3,606	40,490

(1) *Amounts not reduced by unamortized deferred financing and discount costs of $166 million. Additional information is provided in Note 14 of the 2022 Annual Financial Statements*

(2) *Additional information is provided in Note 15 of the 2022 Annual Financial Statements*

(3) *Primarily includes commitments with respect to long-term compensation and employee future benefit arrangements*

(4) *Represents unrecorded commitments. Additional information is provided in Note 26 of the 2022 Annual Financial Statements*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $4.3 billion for 2023 and approximately $22.3 billion over the five-year 2023-2027 Capital Plan. See "Capital Plan" on page 21.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. The Wataynikaneyap Partnership has loan agreements in place to finance the project during construction. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046, respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $339 million for Four Corners. As at December 31, 2022, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $74 million, for which it has issued a parental guarantee. As at December 31, 2022, there was no obligation under this guarantee.

As at December 31, 2022, FortisBC Holdings Inc., a non-regulated holding company, had $142 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $128 million as at December 31, 2022 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

Capital Structure and Credit Ratings

Fortis requires ongoing access to capital and, therefore, targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. The regulated utilities maintain their own capital structures in line with those reflected in customer rates.

Consolidated Capital Structure

As at December 31	**2022** ($ millions)	**2022** (%)	2021 ($ millions)	2021 (%)
Debt [1]	**28,792**	**55.8**	25,784	55.2
Preference shares	**1,623**	**3.1**	1,623	3.5
Common shareholders' equity and non-controlling interests [2]	**21,219**	**41.1**	19,293	41.3
	51,634	**100.0**	46,700	100.0

[1] *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*

[2] *Includes shareholders equity, net of preference shares, and non-controlling interests. Non-controlling interests represented 3.5% as at December 31, 2022 (December 31, 2021 - 3.5%)*

Outstanding Share Data

As at February 9, 2023, the Corporation had issued and outstanding 482.2 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.7 million Series H; 2.3 million Series I; 8.0 million Series J; 10.0 million Series K; and 24.0 million Series M.

Only the common shares of the Corporation have voting rights. The Corporation's first preference shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive or declared.

If all outstanding stock options were converted as at February 9, 2023, an additional 2.3 million common shares would be issued and outstanding.

Credit Ratings

The Corporation's credit ratings shown below reflect its low risk profile, diversity of operations, the stand-alone nature and financial separation of each regulated subsidiary, and the level of holding company debt.

As at December 31, 2022	**Rating**	Type	Outlook
S&P	A-	Corporate	Stable
	BBB+	Unsecured debt	
DBRS Morningstar	A (low)	Corporate	Stable
	A (low)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

In December 2022, S&P lowered Central Hudson’s unsecured debt credit rating to BBB+ from A- and revised the rating outlook to stable from negative. S&P noted that the change was due to projected weakening in the company’s financial measures due to the effects of rising inflation and higher interest rates combined with an elevated capital spending program and increasing operations and maintenance costs.

Capital Plan

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, to meet customer growth, and to deliver cleaner energy.

Capital Expenditures of $4.0 billion were consistent with the 2022 Capital Plan, with $600 million of capital investment focused on delivering cleaner energy to customers.

2022 Capital Expenditures [1]

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**
Total	1,212	709	293	589	510	130	562	**4,005**	**29**	**4,034**

[1] *See "Non-U.S. GAAP Financial Measures" on page 14*

[2] *Energy Infrastructure segment*

Forecast 2023 Capital Expenditures [(1)(2)]

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated**	**Total**
Total	1,103	1,006	384	536	556	132	579	**4,296**	**31**	**4,327**

[(1)] *Represents a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 14.*

[(2)] *Excludes the non-cash equity component of AFUDC*

2023-2027 Capital Plan [(1)]

($ billions)	2023	2024	2025	2026	2027	**Total** [(2) (3)]
Five-year capital plan	4.3	4.2	4.5	4.5	4.8	**22.3**

[(1)] *Capital Plan is a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 14*

[(2)] *Reflects an assumed U.S.:CAD foreign exchange rate of 1.30. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $500 million over the five-year planning period*

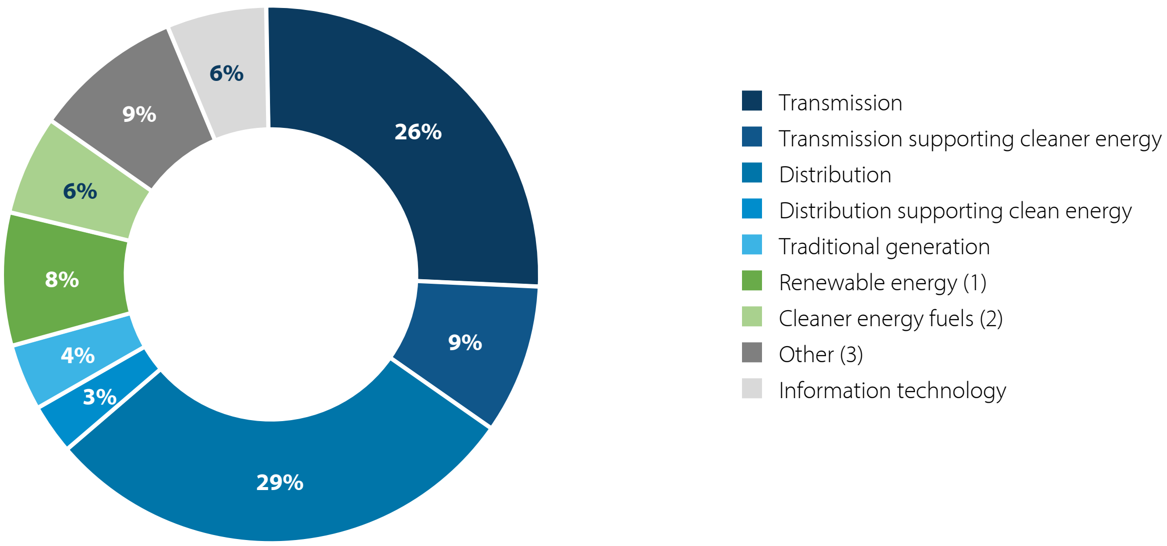
[(3)] *Excludes the non-cash equity component of AFUDC*

The 2023-2027 Capital Plan is $2.3 billion higher than the prior five-year plan that totalled $20 billion. The increase is driven by organic growth, largely reflecting regional transmission projects associated with the MISO LRTP at ITC, additional cleaner energy investments in Arizona to support TEP's planned exit from coal by 2032, and enhancements to distribution infrastructure reliability and capacity, as well as investments to support customer growth, across the Corporation's regulated utilities. Approximately $500 million of the increase is driven by a higher assumed U.S.-to-Canadian dollar exchange rate over the five-year period.

In total, Fortis expects to invest $5.9 billion in cleaner energy over the next five years. These investments will focus on connecting renewables to the grid, including Tranche 1 of MISO's LRTP, renewable and storage investments in Arizona and the Caribbean, and cleaner fuel solutions in British Columbia. The plan incorporates key customer affordability considerations, recognizing the impacts of inflation and elevated commodity costs on customer rates, while ensuring reliable and resilient energy delivery service as we transition to a cleaner energy future.

The investments included in the 2023-2027 Capital Plan are summarized as follows:

Five-Year Capital Plan



[(1)] *Includes clean generation and battery storage*

[(2)] *Includes RNG and LNG*

[(3)] *Includes facilities, equipment and vehicles not included in other categories*

The Capital Plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 17% relating to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the U.S., including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Planned Capital Expenditures are based on forecasts of energy demand as well as labour and material costs, including inflation, supply chain availability, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast.

While global supply chain constraints and rising inflation remain issues of potential concern that continue to evolve, the Corporation does not expect a material impact on its 2023-2027 Capital Plan, although certain planned expenditures may shift within the five years. The Corporation continues to proactively work to mitigate supply chain constraints by identifying high priority materials and consolidating buying power to improve outcomes, increasing inventory levels, and closely working with suppliers to ensure material availability.

Midyear Rate Base (1)

($ billions)	**2022**	2023	2027
ITC	**10.5**	11.1	14.1
UNS Energy	**6.7**	7.0	9.1
Central Hudson	**2.6**	2.7	3.6
FortisBC Energy	**5.4**	5.8	7.6
FortisAlberta	**4.0**	4.2	5.0
FortisBC Electric	**1.6**	1.7	2.0
Other Electric	**3.3**	3.8	4.7
Total	**34.1**	36.3	46.1

(1) *Simple average of Rate Base at beginning and end of the year*

Total midyear Rate Base is forecast to grow to $46.1 billion by 2027 underpinned by the five-year Capital Plan, representing a CAGR of 6.2%.

Major Capital Projects (1)

			Forecast		
($ millions)	Pre-2022	**Actual 2022**	2023	2024-2027	Expected Completion
ITC					
MISO LRTP	—	**—**	—	923	Post-2027
UNS Energy					
Renewable Generation	—	**—**	—	417	Various
Vail-to-Tortolita Transmission Project	21	**46**	106	272	2027
FortisBC Energy					
Tilbury LNG Storage Expansion	16	**9**	17	487	Post-2027
AMI Project	—	**3**	11	410	Post-2027
Eagle Mountain Woodfibre Gas Line Project (2)	—	**—**	—	420	2027
Tilbury 1B Project	29	**11**	27	316	Post-2027
Okanagan Capacity Upgrade	16	**3**	12	188	2025
Other Electric					
Wataynikaneyap Transmission Power Project (3)	355	**169**	117	20	2024
Total		**241**	290	3,453	

(1) *Includes applicable AFUDC*
(2) *Net of forecast customer contributions*
(3) *Fortis' share of estimated capital spending. Under the funding framework, Fortis will be funding its equity component only.*

MISO LRTP

In July 2022, the MISO board approved the first tranche of projects associated with the LRTP, representing 18 transmission projects across the MISO Midwest subregion with total associated costs estimated at US$10 billion. Six of these projects run through ITC's MISO operating companies' service territories, including Michigan and Iowa, where right of first refusal provisions currently exist for incumbent transmission owners. ITC estimates transmission investments of US$1.4 billion to US$1.8 billion through 2030 associated with six of the 18 projects, with capital expenditures of approximately $900 million (US$700 million) included in the Corporation's 2023-2027 Capital Plan. Other projects within ITC's MISO service territory may be subject to competitive bidding, depending on the state in which they are located.

Renewable Generation
Planned renewable generation investments supporting the transition to cleaner energy as outlined in TEP's 2020 IRP. Excludes energy storage investments which are not yet defined. In February 2022, the ACC acknowledged TEP's 2020 IRP, and found it to be reasonable and in the public interest.

Vail-to-Tortolita Transmission Project
Construction and upgrades to connect existing TEP substations to a new 230kV line within TEP's service territory. Construction is expected to begin in 2023 with an anticipated completion date of 2027.

Tilbury LNG Storage Expansion
This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. FortisBC Energy has filed a CPCN application for this project with the BCUC, and if approved, the project is expected to begin in 2023.

AMI Project
Replacement of residential and small commercial meters with advanced meters and installation of bypass valves to support the safety, resiliency, and efficient operation of the gas distribution system. FortisBC Energy has filed a CPCN application with the BCUC for this project.

Eagle Mountain Woodfibre Gas Line Project
Gas line expansion to a proposed LNG site in Squamish, British Columbia. In April 2022, Woodfibre LNG Limited issued a Notice to Proceed to its prime contractor with respect to the project, however, the project remains contingent on certain conditions of Woodfibre LNG Limited and on FortisBC Energy receiving the remaining regulatory and permitting approvals.

Tilbury 1B Project
Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. The project received an Order in Council from the Government of British Columbia in 2017. An initial project scope has been filed with regulators to support the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2023.

Okanagan Capacity Upgrade
Construction of a new section of pipeline and associated facilities to address expected load growth in the Okanagan region. FortisBC Energy has filed a CPCN application with the BCUC for this project.

Wataynikaneyap Transmission Power Project
Construction of an 1,800 kilometer, OEB-regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid, in which Fortis holds a 39% equity interest. FortisOntario is responsible for construction management and operation of the transmission line. In August 2022, Phase 1 of the project was completed, energizing the 230 kV line from Dinorwic to Pickle Lake, Ontario. As at December 31, 2022, the project was 73% complete, with 700 kilometers of transmission line energized and three First Nation communities connected to the Ontario electric grid. Construction is expected to be completed in 2024.

Additional Investment Opportunities

Fortis is pursuing additional investment opportunities within existing service territories that are not yet included in the five-year Capital Plan.

Inflation Reduction Act of 2022
In August 2022, the IRA was passed into U.S. law which included, among other items, a focus on energy security and climate change programs. With incentives and clean energy tax credits encouraging investments in clean energy, energy storage, electric vehicles and manufacturing, the IRA aligns with Fortis' cleaner energy goals and provides an opportunity for continued investment in a cleaner energy future.

ITC - MISO LRTP
The MISO LRTP is expected to consist of four tranches. Incremental opportunity associated the first tranche of projects is outlined above. MISO is expected to identify projects associated with the second tranche of the LRTP in the first half of 2024, which is expected to provide further investment opportunities at ITC.

UNS Energy - TEP 2020 IRP
The TEP 2020 IRP outlines the resource energy transition required to meet customers' energy needs through 2035 as TEP exits coal-fired resources by 2032 and replaces it with wind and solar resources. This transition is expected to reduce carbon emissions 80 percent by 2035. This plan supports reliable and affordable service from sustainable resources and is expected to provide incremental capital investment opportunity of US$2 billion to US$4 billion through 2035. The IRP may be impacted by various federal and state energy policies, including policies currently under consideration. TEP is expected to file its 2023 IRP with the ACC in the second half of 2023.

FortisBC Energy - LNG

LNG infrastructure opportunities in British Columbia include further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment and is close to international shipping lanes.

With respect to further Tilbury expansion, in July 2022, FortisBC Energy's parent company, FortisBC Holdings Inc., entered into an agreement with an Indigenous community to provide the ability to participate, through equity ownership, in certain future LNG investments if the parties are able to satisfy certain obligations. Any proposed transaction is subject to regulatory approvals and certain conditions precedent.

Other Opportunities

Includes incremental regulated transmission investment and grid modernization projects at ITC; energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and cleaner energy infrastructure, as well as climate change adaptation investments across our jurisdictions.

BUSINESS RISKS

Fortis has an ERM program that identifies and evaluates the severity and probability of risks to its business. The Fortis Board, through its audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning. The ERM program at the subsidiary level is overseen by each subsidiary's board of directors and any material risks identified form part of Fortis' ERM program. Materiality thresholds are reviewed annually. Systems of internal controls are used by management to monitor and manage identified risks. A summary of the Corporation's significant business risks follows.

Utility Regulation

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2022. Regulatory jurisdictions include five Canadian provinces, nine U.S. states and three Caribbean countries, as well FERC regulation for transmission assets in the U.S.

Regulators administer legislation covering material aspects of the utilities' business including: customer rates, allowed ROEs and deemed capital structures; capital expenditures; the terms and conditions for the provision of energy and capacity, ancillary services and affiliate services; securities issuances; and certain accounting matters. Regulatory or legislative changes and decisions, and delays in the recovery of costs in rates due to regulatory lag, could have a Material Adverse Effect. The risk of regulatory lag is particularly significant for UNS Energy given the use of historical test years by its regulator in setting customer rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends upon achieving the forecasts established in the rate-setting process. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could adversely affect rates of return. Failure to recover costs and/or earn a return could have a Material Adverse Effect.

For transmission operations, the underlying elements of FERC-established formula rates can be challenged by third parties which could result in rate reductions and customer refunds. These underlying elements include the ROE, ROE adders and deemed capital structure, as well as operating and capital expenditures.

In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. Federal Power Act or the Natural Gas Act, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters.

While Fortis is well-positioned to maintain constructive regulatory relationships through local management teams and subsidiary board of directors comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors. The Corporation and its utilities may experience challenges and compliance costs in responding to such regulatory changes in an effective and timely manner. Any such regulatory changes or operational impacts could have a Material Adverse Effect.

Physical Risks

The provision of electric and gas service is subject to physical risks, including impacts from severe weather and natural disasters, wars, terrorism, vandalism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories.

Certain electric utilities operate in remote or mountainous terrain that can be difficult to access for timely repairs and maintenance, or otherwise face risk of loss or damage from forest fires, floods, hurricanes, storm surges, washouts, landslides, earthquakes, avalanches, snow or ice storms, and other acts of nature. Also, the operation of electricity transmission and distribution assets has the potential to cause fires, mainly as a result of equipment failure, falling trees or lightning strikes to lines or equipment.

The gas utilities are exposed to operational risks associated with natural gas, including fires, explosions, pipeline corrosion and leaks, accidental damage to mains and service lines, equipment failure, damage and destruction from earthquakes, fires, floods and other natural disasters.

Accidents or natural disasters affecting any of the Corporation's electricity or gas utilities can lead to service disruption, spills and commensurate environmental liability, or other liability.

Generating equipment and facilities are subject to physical risks, including equipment breakdown or damage from fire, floods or other natural disasters, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption.

The foregoing risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if their facilities are held responsible for a fire.

Electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, system processes and/or procedures to ensure the safety of employees, contractors and the general public.

Service disruption, other effects and liability, whether caused by the failure to properly implement or complete approved maintenance and capital expenditures, severe weather or other physical risks, if not mitigated through insurance policies or the recovery of such costs in customer rates, could result in loss. Any of the foregoing potential impacts of physical risk could have a Material Adverse Effect.

The foregoing physical risks can be intensified by the "Climate Change" risks discussed below.

Climate Change

Climate-Related Physical Risk

Climate change may negatively impact the ability to provide reliable and safe electric and gas service. The changing climate is predicted to lead to more frequent and severe weather events which may impact or disrupt the reliability of electric or gas systems. The physical risks associated with a changing climate and more frequent and intense weather events requires the Corporation’s utilities to respond to continue delivering reliable service to customers.

Severe weather impacts the Corporation's service territories, primarily in the form of thunderstorms, flooding, wildfires, hurricanes, storm surges, atmospheric rivers and snow, or ice storms. Increased frequency of extreme weather events could increase the cost of providing service through increased repairs and use of contingency plans. Extreme weather conditions and changes in air temperature require system backup and can result in system stress, including service disruptions, and decreased efficiency of operating facilities over time. Changes in precipitation that result in droughts could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations.

Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels, larger storm surges and floods, could result in service disruption, shortened asset life, increased repair and replacement costs, and costs associated with strengthened design standards and systems. The impacts of climate change can intensify the "Physical Risks" described on page 25.

The physical risks posed by the impacts of climate change and resultant service disruption and repair and replacement costs could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

Climate-Related Transition Risk

As economies transition toward decarbonization and increase renewable energy use under various national and international commitments, risks arise related to associated policy, legal, technological and market changes, which may have related capital and financial implications for the Corporation and its utilities.

The impacts of the transition to a cleaner energy future will require the Corporation’s utilities to effectively manage, among other things, evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to appropriately respond to climate change and decarbonize may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts.

Fortis expects the pace of government policy and regulatory changes to accelerate in the coming years (see "Environmental Regulation" on page 27). Further, the emergence of initiatives designed to reduce GHG emissions, increase renewable energy use, and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce renewable energy, enable more efficient storage of energy and reduce energy consumption. As new technologies become widely available, infrastructure design risks and time delays may emerge. Utility energy delivery systems will require technological changes and updates in order to effectively deliver increasing amounts of renewable energy to customers (see "Technology Developments" on page 28).

The availability of regulatory mechanisms or the ability of the Corporation's utilities to pass related costs on to customers remains uncertain. Regulatory lag in relation to the adoption of climate change initiatives and/or the availability of regulatory recovery mechanisms in certain jurisdictions could contribute to financial harm to Fortis and its utilities (see "Utility Regulation" on page 25).

Fortis has a plan to reduce GHG direct emissions 50% by 2030 and 75% by 2035 without the use of carbon offsets or new technology. Technological advancements will be required in order for the Corporation to eliminate the last 25% of its GHG direct emissions by 2050 to achieve its net-zero target while preserving system reliability and customer affordability. In addition to the development and implementation of relevant energy technologies, the Corporation's ability to achieve its climate-related targets depends upon many factors, including the size of the Corporation's service territory, capacity needs remaining in line with current expectations, the impacts of future regulations or legislation, or the adoption of alternative energy products by the public, any of which could cause actual results and the ability to achieve such targets to materially differ from expectations. The ultimate impact of achieving or failing to achieve such targets could cause reputational damage which could result in a Material Adverse Effect.

Growth

Fortis has a history of both growth through acquisitions and organic growth from capital investment in existing service territories. The Corporation's dividend growth guidance is significantly dependent upon achieving the Rate Base growth expected from the execution of the five-year Capital Plan as described under "Capital Plan" on page 21. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by commodity price fluctuations, supply and labour costs, supply chain constraints, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation's control. There is no assurance that regulators will approve: (i) all of the planned projects or their amounts or timing; (ii) permits in a timely manner, or with reasonable terms and conditions; or (iii) the recovery of cost overruns in customer rates, which may have a Material Adverse Effect.

Environmental Regulation

The Corporation's businesses are subject to environmental laws and regulations, including those which concern emissions into the air, discharges into water or soil, use of water, hazardous waste disposal and containment, and the investigation and remediation of contamination, among others.

The risk of contamination of air, soil and water associated with electricity operations primarily relates to: (i) the transportation, handling, storage and combustion of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil; (iii) the management and disposal of coal combustion residuals and other wastes; and (iv) accidents resulting in hazardous release at or from coal mines that supply generating facilities. Contamination risks at gas operations primarily relate to leaks and other accidents involving gas systems. The key environmental risks for hydroelectric generation operations include dam failures and the creation of artificial water flows that may disrupt natural habitats.

Failure to comply with environmental laws and regulations, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other penalties. Further, liabilities relating to contamination investigation and remediation, and related claims for personal injury or property damage, may arise at many locations, including formerly and currently owned/operated properties and waste treatment or disposal sites, regardless of whether such contamination was caused by the business at the time it owned the property, whether it resulted from non-compliance with applicable environmental laws and regulations, or whether it resulted from any act or omission of the business. These liabilities could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance or through regulatory mechanisms, these foregoing costs could have a Material Adverse Effect.

Environmental laws and regulations continue to develop and may result in significant additional expense. In particular, the management of GHG emissions and related decarbonization requirements is a major concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines. Regulation and the pace of regulatory change to address reliability, resiliency, resource planning and safety is expected to increase in response to climate change. Future legislation could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect (see "Climate Change" at page 26).

Pandemics and Public Health Crises

The Corporation could be negatively impacted by widespread outbreaks of communicable diseases or other public health crises that cause economic and/or other disruptions. Outbreaks of communicable diseases, as well as efforts to reduce the health impacts and control disease spread, can lead to restrictions on business operations, including business closures and the potential impacts of reduced labour availability and productivity, supply chain disruptions, project construction delays, disruptions to capital markets, governmental and regulatory action, and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill (see "General Economic Conditions" on page 29).

The Corporation's utilities provide essential services and must be operational and maintained throughout any pandemic or public health crisis, though such events can challenge operations and increase operating costs. The duration and severity of a pandemic or public health crisis, could have a Material Adverse Effect.

Health and Safety

The operations of the Corporation's utilities inherently involve risk to the health and safety of both employees and the public. Personal injury or loss of life could result from failure to implement or observe appropriate health and safety procedures and gives rise to operational, reputational or financial impacts, any of which could have a Material Adverse Effect. In addition, failure to comply with health and safety regulations could result in fines, penalties, reputational damage, litigation, increased capital and operating costs or adverse regulatory outcomes.

Natural Gas Competitiveness

Approximately 23% of the Corporation's revenue is derived from the delivery of natural gas. In British Columbia, which accounts for 82% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating load. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive due to price or other factors, such as the carbon intensity of natural gas relative to other energy sources, the ability to add new customers could be impaired. Existing customers could also reduce their consumption or switch to electricity, placing further pressure on rates and, in the extreme, could ultimately lead to an inability to recover the utility's cost of service through customer rates.

Government policy could further impact the competitiveness of natural gas in British Columbia. As governments develop policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to other energy sources.

Additionally, there are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as the carbon intensity of the energy source and the type of housing stock being built. As part of their own climate change policy plans, local governments may use various tools at their disposal such as franchise agreements, permits, building codes and zoning bylaws to impose limitations on energy sources permitted in new and existing developments. Municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Corporation's ability to attract new natural gas customers or retain existing customers.

A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

Cybersecurity and Information and Operations Technology

As operators of critical energy infrastructure, the Corporation's utilities are at risk of cybercrime. The ability of the Corporation's utilities to operate effectively is dependent upon using and maintaining complex information systems and infrastructure that: (i) support the operation of generation, transmission and distribution facilities, including electric and gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations. The Corporation also engages third-party service providers to help facilitate the management of the Corporation's information security systems, communication tools and data processing.

Information and operations technology systems, including those of the Corporation's third-party service providers, may be vulnerable to unauthorized access or disruption due to cyber- and other attacks, including hacking, malware, acts of war or terrorism, and acts of vandalism, among others. Further, geopolitical conflicts may further increase the sophistication, magnitude or frequency of cyberattacks, some of which may even be initiated by nation state actors. Any such event could result in the disruption of energy service and other business operations, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business information or personal information of customers and/or employees.

A material cybersecurity breach of the Corporation's information security systems or those of a third-party service provider could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

Technology Developments

New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to impact retail sales. Heightened awareness of energy costs and environmental concerns have increased demand for products that reduce energy consumption. The Corporation's utilities are also promoting demand-side management programs. New technologies available to customers include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect.

Further, the implementation of new information technology systems into the business, including those impacting utility operations and customer billing systems, carries risk that any such system will not operate as expected. Failure to maintain, upgrade, replace or properly implement such new information technology systems could result in increased risk of a cybersecurity incident and have an adverse effect on operational efficiency, revenue or reputation (see "Cybersecurity and Information and Operations Technology" above).

Weather Variability and Seasonality

Electricity consumption varies significantly in response to seasonal weather changes which have been and will continue to be impacted by climate change (see "Climate Change" on page 26). Cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability. Hydroelectric generation is sensitive to rainfall levels and unexpected variations in seasonal rainfall levels can negatively impact operations.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of natural gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities are typically highest in the first and fourth quarters. Regulatory deferral and revenue decoupling mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence or the discontinuance of key regulatory mechanisms could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates, consultations, and other approvals from various levels of government, regulators, government agencies and/or other third parties. There is no assurance that: (i) such approvals will be obtained, continuously maintained or renewed without delay; and (ii) the terms and conditions thereof will be fully complied with at all times and will not change in a material adverse manner. Significant failures in these regards could prevent the operation of the businesses and have a Material Adverse Effect.

Reliability Standards

The Energy Policy Act requires owners, operators and users of the bulk electric system in the U.S. to meet mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these, or similar, standards have been adopted in certain Canadian provinces including British Columbia and Alberta. The failure to develop, implement and maintain appropriate operating practices/systems and capital plans to address reliability obligations could lead to compliance violations and a Material Adverse Effect, including as a result of the exclusion of related costs from customer rates and other potentially significant penalties.

Indigenous Peoples' Land Claims

In British Columbia, the Corporation's utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. Various treaty negotiation processes involving Indigenous Peoples and the Governments of British Columbia and Canada are underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in such processes. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing third-party rights; however, there is no assurance that the settlement processes will not have a Material Adverse Effect.

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by a third party. Some of these permits require approvals from First Nations and Crown-Indigenous Relations and Northern Affairs Canada. FortisAlberta may be unable to obtain such approvals or negotiate land-use agreements with reasonable terms. Significant failures in these regards could have a Material Adverse Effect.

Certain jointly owned facilities and portions of TEP's transmission lines are located on tribal lands pursuant to leases, land easements and other rights-of-way that are effective for specified time periods. The inability to receive future approvals for continued access to the facilities and land could have a Material Adverse Effect.

Joint-Ownership Interests and Third-Party Operators

Certain generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have sole discretion or any ability to affect the management or operations of such facilities, including how to best address changing economic conditions or environmental requirements. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

Wataynikaneyap Partnership, which is owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), is responsible for the Wataynikaneyap Transmission Power Project. Fortis does not have sole discretion on decisions for the project and divergence in the interest of Fortis and the other partners could delay the project's completion, increase its anticipated cost, or adversely affect the reputation of Fortis, any of which could have a Material Adverse Effect.

General Economic Conditions

Fluctuations in general economic conditions, inflation, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors may lower energy demand and reduce sales and reduced capital spending, particularly to the extent that related customer and Rate Base growth are impacted. A severe and prolonged economic downturn could also impair customers' ability to pay their bills in a timely manner. Each of these factors could lead to the impairment of goodwill or other long-term assets, and could have a Material Adverse Effect. Further, the impact of macroeconomic factors, including, but not limited to, international relations and geopolitical events, could cause weaker economic conditions or increase the volatility of the equity capital markets, which could impact the business and financial condition of the Corporation or adversely impact the Corporation's share price.

Commodity Price Volatility

Purchased power and gas, and generation fuel costs are subject to commodity price volatility, which is managed through regulator-approved: (i) mechanisms that permit the flow through in customer rates of commodity price changes and/or that provide for rate-stabilization and other deferral accounts; and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 35).

There is no assurance that current regulator-approved mechanisms or strategies will continue to exist in the future. Additionally, despite these mechanisms and strategies, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and sales growth, which could have a Material Adverse Effect.

Purchased Power Supply

A significant portion of electricity and gas sold by the Corporation's utilities is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers and is not being generated by the Corporation's utilities. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could result in a loss and/or increase in the cost of purchased power and gas, which could have a Material Adverse Effect. The cost and availability of purchased power and gas may be adversely impacted by factors discussed under "Climate Change" on page 26, "Environmental Regulation" on page 27 and "Commodity Price Volatility" on page 29.

Counterparty Credit Risk

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable due to the suspension of collection efforts in response to the COVID-19 Pandemic, as well as higher commodity prices. Central Hudson continues to proactively contact customers regarding past-due balances to advise them of financial assistance available through federal and state programs, and collection efforts are expected to expand in 2023. Under its regulatory framework, Central Hudson can defer uncollectible write-offs that exceed 10 basis points above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

There is no assurance that credit risk management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Supply Chain

Domestic and global supply chain issues may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the operation of the Corporation's utilities. Failure to eliminate or manage the constraints in the supply chain may impact the availability of items that are necessary to support operations as well as materials that are required for continued infrastructure growth and could have a Material Adverse Effect.

Interest Rates

Generally, the market price of the Corporation's common shares is inversely sensitive to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates. While a rising interest environment could result in higher allowed ROEs, such ROE changes tend to lag as a result of regulatory timelines. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes. Although interest costs at the regulated utilities are generally recovered through customer rates, the discontinuance of regulatory mechanisms that permit the flow-through of actual interest costs, the impact of regulatory lag at UNS Energy, and higher finance costs on holding company debt could have a Material Adverse Effect.

Foreign Exchange Exposure

As at December 31, 2022, 67% of the Corporation's assets were located outside Canada and 59% of 2022 revenue was derived from foreign operations. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation’s $22.3 billion five-year Capital Plan for 2023 through 2027 also includes exposure to foreign exchange.

Fortis has limited its U.S. dollar currency exposure through hedging. The Corporation has issued and designated U.S. dollar-denominated long-term debt as an effective hedge of foreign net investments. Fortis has also entered into foreign exchange contracts and cross-currency swaps to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, earnings and cash flow continue to be impacted by exchange rate fluctuations. In addition, there is no assurance that existing hedging strategies will continue to be effective, and therefore a significant, prolonged decrease in the U.S. dollar-to-Canadian dollar exchange rate could have a Material Adverse Effect.

Access to Capital

The Corporation and certain of its subsidiaries have incurred material amounts of indebtedness. Ongoing access to cost-effective capital is required to fund, among other things, capital expenditures and the repayment of maturing debt.

Operating Cash Flow may not be sufficient to fund the repayment of all outstanding liabilities when due or fund anticipated capital expenditures.

The ability to meet long-term debt repayments is dependent upon obtaining sufficient and cost-effective financing to replace maturing indebtedness. The ability to arrange financing is subject to numerous factors, including the results of operations and financial condition of Fortis and its subsidiaries, the regulatory environments including regulatory decisions regarding capital structure and allowed ROEs, capital market conditions, general economic conditions, credit ratings, and the environmental, social and governance profile of Fortis and its subsidiaries. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

Fortis is a holding company and, as such, has no revenue-generating operations of its own. The Corporation’s subsidiaries are separate legal entities and have no independent obligation to pay dividends to Fortis. Prior to paying dividends to the Corporation, the subsidiaries have financial obligations that must be satisfied, including, among others, their operating expenses and obligations to creditors. Furthermore, the Corporation’s utilities are required by regulation to maintain a minimum equity-to-total capital ratio that may restrict their ability to pay dividends to the Corporation or may require the Corporation to contribute capital to such subsidiaries. The future enactment of laws or regulations may prohibit or further restrict the ability of the Corporation's subsidiaries to pay dividends or to repay intercorporate indebtedness. In addition, in the event of a subsidiary’s liquidation or reorganization, the Corporation’s right to participate in a distribution of assets is subject to the prior claims of the subsidiary’s creditors. As a result, the Corporation’s ability to generate cash flow to service its debt obligations is reliant on the ability of its subsidiaries to generate sustained earnings and cash flows and to pay dividends and repay loans.

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 17.

Taxation

Earnings at Fortis and its subsidiaries could be impacted by changes in income tax rates and other tax legislation in Canada, the U.S. and other international jurisdictions. The nature, timing or impact of changes in tax laws cannot be predicted and could have a Material Adverse Effect. Although income taxes at the regulated utilities are generally recovered in customer rates, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods. At the non-regulated level, changes in income tax rates and other tax legislation could materially affect the after-tax cost of existing and future debt which is not recoverable in customer rates.

Insurance

Insurance is maintained with reputable industry insurers for property damage, potential liabilities and business interruption for coverage considered appropriate and in accordance with industry practice.

A significant portion of transmission and distribution assets is uninsured, as is customary in North America, as the cost to insure such assets is prohibitive. Insurance is subject to coverage limits and deductibles, as well as time-sensitive claims discovery and reporting provisions. There is no assurance that: (i) the amounts and types of losses from actual damage, liabilities or business interruption will be fully covered by insurance; (ii) regulatory relief would be obtained for coverage shortfalls; (iii) adequate insurance at reasonable rates will continue to be available; or (iv) insurers will fulfill their obligations. Significant actual shortfalls in insurance coverage or claims payment could have a Material Adverse Effect. The availability and cost of certain types of insurance may be adversely impacted by the risks described under "Climate Change" on page 26.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of a skilled workforce as well as filling strategic positions. Like its peers, Fortis faces demographic challenges and competitive markets relating to trades, technical and professional staff, particularly considering its significant Capital Plan. ITC relies heavily on agreements with third parties to provide services for the construction, maintenance and operation of certain aspects of its business. Significant failures in attracting or retaining a skilled workforce or filling strategic positions within the Corporation or its utilities could have a Material Adverse Effect.

Labour Relations

Most of the Corporation's utilities employ members of labour unions or associations under collective bargaining agreements. Fortis considers its labour relationships to be satisfactory, but there is no assurance that this will continue or that existing collective bargaining agreements will be renewed on reasonable terms without work disruption or other job action. Significant failures in these regards could cause service interruptions and/or labour cost increases for which regulators may not allow full recovery in customer rates, and could have a Material Adverse Effect.

Post-Retirement Obligations

Fortis and most of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain employees and retirees. The most significant cost drivers for these plans are investment performance and interest rates, which are affected by global financial markets. Regulatory deferral mechanisms are in place at many of the Corporation’s utilities that permit the flow through in customer rates of certain impacts associated with market fluctuations. Severe and prolonged market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, changes in laws and regulations, as well as changes in existing regulatory treatment of post-retirement benefit costs, may increase plan expenses or require additional plan funding and could have a Material Adverse Effect.

Political Environment

The political environment, at the local, national or global level, may impact energy laws, governmental energy policies or regulatory decisions. For example, political pressure or intervention to address rising energy prices and customer affordability concerns may impact regulatory decisions, as well as the period over which the Corporation’s utilities recover allowed costs.

The business is further exposed to risks associated with international relations and geopolitical events. Political, economic or social instability or events, trade disputes, increased tariffs, changes in laws or the imposition of onerous regulations applicable to existing operations, currency restrictions, and the impacts of changes in political leadership could lead to an increase in commodity prices, impact the availability and cost of energy or generally affect global economic conditions, any of which could have a Material Adverse Effect (see "Environmental Regulation" at page 27 and "General Economic Conditions" at page 29).

Reputation, Relationships and Stakeholder Activism

There can be no assurance that internal processes, controls or audits will ensure compliance with the Corporation's internal policies, including its Code of Conduct, or anti-bribery and anti-corruption laws. Employees, affiliates, independent contractors or agents may violate such policies and laws, which may potentially lead to reputational damage, in addition to potential fines, penalties or litigation, any of which could have a Material Adverse Effect.

The Corporation's operations and growth prospects require strong relationships with key stakeholders, including regulators, governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction of Major Capital Projects, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development. See "Required Approvals" and "Indigenous Land Claims" at page 29.

External stakeholders are increasingly challenging companies regarding climate change, sustainability, diversity, returns (including ROEs and ROAs), executive compensation and other matters. Public opposition to larger infrastructure projects is becoming increasingly common, which can challenge capital plans and resultant organic growth. While the Corporation actively monitors such activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively manage or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings

Legal, administrative and other proceedings arise in the ordinary course of business and may include environmental claims, employment-related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, actions by regulatory or tax authorities, and other matters. Unfavourable outcomes such as judgments or settlements for monetary or other damages, injunctions, denial or revocation of permits, reputational harm, and other results could have a Material Adverse Effect.

ACCOUNTING MATTERS

Critical Accounting Estimates

General

The preparation of the 2022 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulatory Assets and Liabilities

As at December 31, 2022, Fortis recognized regulatory assets of $4.0 billion (2021 - $3.6 billion) and regulatory liabilities of $3.9 billion (2021 - $3.2 billion).

Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

The recognition of regulatory assets and liabilities and the period(s) of settlement are often estimates based on past, existing or expected regulatory orders in relation to the nature of the underlying amounts, and are subject to regulatory approval. There is no assurance that actual settlement amounts and the related settlement periods will not be materially different from those estimated. Differences arising from the regulator's orders would be recognized in accordance with those orders, whereby any amounts disallowed would be immediately recognized in earnings with the remainder recognized in earnings in accordance with their inclusion in customer rates.

Employee Future Benefits

Key Estimates and Assumptions Years ended December 31 *($ millions, except as indicated)*	**Defined Benefit Pension Plans** **2022**	2021	**OPEB Plans** **2022**	2021
Funded status: (1)				
Benefit obligation (2)	**(3,063)**	(3,922)	**(582)**	(747)
Plan assets	**3,079**	3,722	**389**	440
	16	(200)	**(193)**	(307)
Net benefit cost (2)	**19**	64	**26**	35
Key assumptions: *(weighted average %)*				
Discount rate: (3)				
During the year	**2.97**	2.60	**2.97**	2.60
As at December 31	**5.27**	3.00	**5.36**	2.97
Expected long-term rate of return on plan assets (4)	**5.87**	5.40	**5.00**	4.88
Rate of compensation increase	**3.33**	3.30	**—**	—
Health care cost trend increase rate (5)	**—**	—	**4.48**	4.49

(1) *Periodic actuarial valuations determine funding contributions for the pension plans and U.S. OPEB plans, while Canadian OPEB plans are unfunded*

(2) *Actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, average remaining service life of employees, mortality rates and, for OPEB plans, expected health care costs*

(3) *Reflects market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments*

(4) *Developed using best estimates of expected returns, volatilities and correlations for each class of asset. Estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes*

(5) *Actuarially determined, the projected 2023 rate is 6.17% and is assumed to decrease over the next 12 years to the ultimate rate of 4.48% in 2034 and thereafter*

Sensitivity Analysis Year ended December 31, 2022 *($ millions)*	**Rate of Return 1% change** **Increase**	**Decrease**	**Discount Rate 1% change** **Increase**	**Decrease**	**Health Care Costs Trend Rate 1% change** **Increase**	**Decrease**
Defined benefit pension plans:						
Net benefit cost	**(33)**	**27**	**(35)**	**62**	**n/a**	**n/a**
Projected benefit obligation	**17**	**(49)**	**(337)**	**401**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(5)**	**5**	**(12)**	**12**	**17**	**(13)**
Accumulated benefit obligation	**—**	**—**	**(70)**	**85**	**64**	**(57)**

At the regulated utilities, changes in net benefit cost are generally expected to be reflected in customer rates, subject to regulatory lag and forecast risk at certain utilities.

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations between actual net pension cost and that forecast and reflected in customer rates. There is no assurance that these deferral mechanisms will continue in the future.

Depreciation and Amortization

As at December 31, 2022, Fortis recognized property, plant and equipment and intangible assets of $43.2 billion (2021 - $39.2 billion) representing 67% of total assets (2021 - 68%). Depreciation and amortization of these assets totalled $1.6 billion for 2022 (2021 - $1.4 billion).

Depreciation and amortization reflect the estimated useful lives of the underlying assets, which considers historical experience, manufacturers' ratings and specifications, the past and expected future pattern and nature of usage, and other factors.

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future removal costs, not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2022, this regulatory liability was $1.3 billion (2021 - $1.2 billion).

Depreciation rates at the regulated utilities are typically determined through periodic depreciation studies performed by external experts. Where actual experience differs from previous estimates, resultant differences are generally reflected in future depreciation rates and thereby recovered or refunded through customer rates in the manner prescribed by the regulator.

Goodwill Impairment

As at December 31, 2022, Fortis recognized goodwill of $12.5 billion (2021 - $11.7 billion), representing 19% of total assets (2021 - 20%). The increase in goodwill was due to the impact of foreign exchange associated with the translation of U.S. dollar-denominated goodwill.

Goodwill at each of the Corporation's 11 reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

The recognition of impairment losses could have a Material Adverse Effect. Such losses are not recoverable in regulated utility rates. To the extent impairment losses signal lower expected future cash flows to support interest payments on unregulated holding company debt and dividends on common shares, they could adversely affect the future cost of such capital, expressed as higher interest rates on such debt, which is not recoverable in regulated utility rates, and lower common share market prices.

Income Tax

As at December 31, 2022, deferred income tax liabilities, current income tax payable included in accounts payable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $4.1 billion, $88 million, $1.9 billion and $1.4 billion, respectively (2021 - $3.6 billion, $31 million, $1.8 billion and $1.3 billion, respectively). Income tax expense was $289 million in 2022 (2021 - $234 million).

Current income taxes reflect the estimated taxes payable/receivable in the current year based on enacted tax rates and laws, and the estimated proportion of taxable earnings/loss attributable to various jurisdictions.

Deferred income tax assets and liabilities reflect temporary differences between the tax and accounting basis of assets and liabilities. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. A valuation allowance is recognized in earnings to the extent that future tax recovery is not assessed as "more likely than not".

At the regulated utilities, differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities. These are subsequently amortized to earnings in accordance with their inclusion in customer rates pursuant to the regulator's orders. Otherwise, changes in expectations and resultant estimates arising from changes in tax rates, tax laws, jurisdictional earnings allocations and other factors are recognized in earnings upon occurrence.

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2018 to 2022 taxation years are still open for audit in Canadian jurisdictions, and its 2018 to 2022 taxation years are still open for audit in U.S. jurisdictions. The impact of such income tax compliance examinations could be material to the Corporation's financial statements (see "Business Risks - Taxation" on page 31).

In August 2022, the IRA was passed into U.S. law. The legislation will be funded, in part, by the introduction of a new 15% corporate alternative minimum income tax, effective for tax years beginning after December 31, 2022. While this tax is expected to be applicable to Fortis, the Corporation does not currently expect it to have a material impact on its financial results, Operating Cash Flow or credit ratings.

In November 2022, the Department of Finance Canada released revised draft legislation which included a proposal on interest deductibility. It is unknown when the legislation may be enacted. In addition, the 2021 Canadian federal budget included proposed changes in relation to international taxation. There has been no significant update on this proposal, and it is unknown when draft legislation may be available. Changes in tax legislation could affect the results of operations, financial condition and cash flows of the Corporation as discussed under “Business Risks - Taxation” on page 31. Fortis will continue to assess the impacts as more details on the tax proposals become available.

Derivatives

The fair values of derivatives are based on estimates that cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting future earnings or cash flows.

Contingencies

The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Legal, Administrative and Other Proceedings" on page 32, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 26 in the 2022 Annual Financial Statements.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2022, the carrying value of long-term debt, including the current portion, was $28.6 billion (2021 - $25.5 billion) compared to an estimated fair value of $25.8 billion (2021 - $28.8 billion). Since Fortis does not intend to settle long-term debt prior to maturity, the excess of fair value over carrying value does not represent an actual liability.

The consolidated carrying value of the remaining financial instruments, other than derivatives, approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception.

Energy contracts subject to regulatory deferral

UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2022, unrealized losses of $84 million (2021 - $20 million) were recognized as regulatory assets and unrealized gains of $224 million (2021 - $52 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2022, unrealized gains of $34 million (2021 - $21 million) were recognized in revenue.

Total return swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $114 million and terms of one to three years expiring at varying dates through January 2025. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2022, unrealized losses of $22 million (2021 - unrealized gains of $17 million) were recognized in other income, net.

Foreign exchange contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through May 2024 and have a combined notional amount of $352 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2022, unrealized losses of $9 million (2021 - $11 million) were recognized in other income, net.

Interest rate swaps

ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of US$450 million, were terminated in September 2022 with the issuance of US$600 million senior notes and realized gains of $52 million (US$39 million) were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

Cross-Currency interest rate swaps

In May 2022, the Corporation entered into cross-currency interest rate swaps with a 7-year term to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR rates. In 2022, unrealized losses of $17 million were recorded in other comprehensive income.

Other investments

UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. These investments are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2022, unrealized losses of $11 million (2021 - unrealized gains of $5 million) were recognized in other income, net.

Derivative Fair Values

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1** (1)	**Level 2** (1)	**Level 3** (1)	**Total**
As at December 31, 2022				
Assets (2)				
Energy contracts subject to regulatory deferral	**—**	**304**	**—**	**304**
Energy contracts not subject to regulatory deferral	**—**	**49**	**—**	**49**
Other investments	**150**	**—**	**—**	**150**
	150	**353**	**—**	**503**
Liabilities (3)				
Energy contracts subject to regulatory deferral	**—**	**(164)**	**—**	**(164)**
Energy contracts not subject to regulatory deferral	**—**	**(8)**	**—**	**(8)**
Foreign exchange contracts, total return and cross-currency interest rate swaps	**—**	**(26)**	**—**	**(26)**
	—	**(198)**	**—**	**(198)**
As at December 31, 2021				
Assets (2)				
Energy contracts subject to regulatory deferral	—	78	—	78
Energy contracts not subject to regulatory deferral	—	16	—	16
Foreign exchange contracts, total return and interest rate swaps	23	2	—	25
Other investments	137	—	—	137
	160	96	—	256
Liabilities (3)				
Energy contracts subject to regulatory deferral	—	(46)	—	(46)
Energy contracts not subject to regulatory deferral	—	(3)	—	(3)
	—	(49)	—	(49)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1 - unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*

(2) *Included in cash and cash equivalents, accounts receivable and other current assets or other assets*

(3) *Included in accounts payable and other current liabilities or other liabilities*

Derivative Volumes

As at December 31	2022	2021
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**586**	509
Electricity power purchase contracts *(GWh)*	**224**	731
Gas swap contracts *(PJ)*	**185**	151
Gas supply contract premiums *(PJ)*	**148**	144
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,886**	1,886
Gas swap contracts *(PJ)*	**34**	29

[1] *Energy contracts settle on various dates through 2029*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2022	2021	2020
Revenue	**11,043**	9,448	8,935
Net earnings	**1,514**	1,405	1,389
Common Equity Earnings	**1,330**	1,231	1,209
EPS: *($)*			
Basic	**2.78**	2.61	2.60
Diluted	**2.78**	2.61	2.60
Total assets	**64,252**	57,659	55,481
Long-term debt (excluding current portion)	**25,931**	23,707	23,113
Dividends declared: *($)*			
Per common share	**2.200**	2.080	1.965
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G	**1.0983**	1.0983	1.0983
Series H [1]	**0.4588**	0.4588	0.5003
Series I [2]	**0.9157**	0.3926	0.4987
Series J	**1.1875**	1.1875	1.1875
Series K	**0.9823**	0.9823	0.9823
Series M	**0.9783**	0.9783	0.9783

[1] *The annual dividend per share was reset to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025*

[2] *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield*

2022/2021

For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 3, "Operating Results" on page 9, and "Financial Position" on page 16.

2021/2020

The increase in revenue was due primarily to: (i) higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) new customer rates, effective January 1, 2021 and higher wholesale sales at TEP; and (iv) higher retail electricity sales, primarily in Western Canada and the Caribbean, partially offset by lower sales in Arizona due to unfavourable weather. The increase in revenue was partially offset by an unfavourable foreign exchange impact of $345 million and a $40 million favourable base ROE adjustment recognized at ITC in 2020 as a result of the May 2020 FERC decision.

Common Equity Earnings increased by $22 million compared to 2020. Growth in Common Equity Earnings was tempered by the unfavourable impact of foreign exchange of $48 million, and significant one-time items recognized in 2020 of $14 million. The significant items in 2020 included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform. These impacts were partially offset by unrealized mark-to-market gains of $12 million in 2021 on natural gas derivatives at Aitken Creek.

Excluding the impact of the above noted items, the Corporation delivered higher earnings of $72 million reflecting: (i) Rate Base growth; (ii) higher earnings in Arizona primarily due to new customer rates at TEP effective January 1, 2021, partially offset by lower sales due to unfavourable weather and higher operating costs; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) higher sales at FortisAlberta associated with favourable weather, partially offset by a higher effective income tax rate. This growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Aitken Creek due to realized losses on natural gas contracts.

In addition to the above-noted items impacting earnings, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

The increase in total assets was due to capital expenditures in 2021 as well as an increase in employee future benefit balances, driven by higher discount rates, partially offset by unfavourable foreign exchange on the translation of U.S. dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales

(GWh, except as indicated)	**2022**	2021	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,264**	2,206	58
Wholesale Electricity	**1,247**	1,749	(502)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity	**1,158**	1,203	(45)
Gas *(PJ)*	**8**	6	2
FortisBC Energy *(PJ)*	**75**	74	1
FortisAlberta	**4,200**	4,147	53
FortisBC Electric	**967**	927	40
Other Electric	**2,443**	2,449	(6)
Non-Regulated			
Energy Infrastructure	**83**	13	70

The decrease in electricity sales was driven by UNS Energy due to lower wholesale electricity sales, partially offset by higher retail electricity sales due to favourable weather and customer growth. The decrease was partially offset by higher electricity sales in: (i) Fortis Belize, due to higher hydroelectric production associated with rainfall levels; and (ii) FortisAlberta, due to higher load from industrial customers and higher average consumption by residential customers.

The increase in gas sales was driven by Central Hudson due to higher average consumption by commercial and industrial customers.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2022**	2021	Variance	**2022**	2021	Variance
Regulated Utilities						
ITC	**500**	418	82	**126**	103	23
UNS Energy	**716**	540	176	**45**	33	12
Central Hudson	**396**	283	113	**37**	39	(2)
FortisBC Energy	**725**	592	133	**84**	78	6
FortisAlberta	**169**	156	13	**34**	23	11
FortisBC Electric	**136**	133	3	**14**	14	—
Other Electric	**448**	401	47	**40**	29	11
Non-regulated						
Energy Infrastructure	**78**	60	18	**49**	40	9
Corporate and Other	**—**	—	—	**(59)**	(31)	(28)
Total	**3,168**	2,583	585	**370**	328	42
Weighted average number of common shares outstanding *(# millions)*				**481.1**	473.7	7.4
Basic EPS *($)*				**0.77**	0.69	0.08

The increase in revenue was due primarily to: (i) higher flow-through costs in customer rates, driven by higher commodity prices; (ii) Rate Base growth; (iii) higher wholesale and transmission revenue, as well as retail electricity sales at UNS Energy; and (iv) favourable foreign exchange of $106 million.

The increase in Common Equity Earnings was driven by: (i) Rate Base growth; (ii) higher retail electricity sales and transmission revenue at UNS Energy; (iii) higher earnings from the energy infrastructure segment driven by hydroelectric production in Belize, as well as the favourable impact of market conditions at Aitken Creek; and (iv) the timing of expenses at FortisAlberta. The translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results with these impacts exceeding the related losses associated with hedging activities. The increase in earnings was partially offset by higher corporate costs, reflecting higher finance costs and a lower income tax recovery, as well as lower earnings at Central Hudson, reflecting the finalization of the company's rate application in late 2021 with retroactive application to July 1, 2021.

The increase in basic EPS reflects higher Common Equity Earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	**2022**	2021	Variance
Cash and cash equivalents, beginning of period	**395**	225	170
Cash from (used in):			
Operating activities	**869**	717	152
Investing activities	**(1,152)**	(985)	(167)
Financing activities	**103**	174	(71)
Effect of exchange rate changes on cash and cash equivalents	**(6)**	—	(6)
Cash and cash equivalents, end of period	**209**	131	78

Operating Activities

Operating Cash Flow increased due to: (i) higher cash earnings, reflecting Rate Base growth, as well as higher retail electricity sales and transmission revenue in Arizona; (ii) favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates, and (iii) the higher U.S.-to-Canadian dollar exchange rate. The increase was partially offset by the timing of inventory purchases at UNS Energy.

Investing Activities

The variance reflects higher capital expenditures in accordance with the Corporation's 2022 Capital Plan.

Financing Activities

See "Cash Flow Summary" on page 18.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2022	**3,168**	**370**	**0.77**	**0.77**
September 30, 2022	**2,553**	**326**	**0.68**	**0.68**
June 30, 2022	**2,487**	**284**	**0.59**	**0.59**
March 31, 2022	**2,835**	**350**	**0.74**	**0.74**
December 31, 2021	2,583	328	0.69	0.69
September 30, 2021	2,196	295	0.63	0.62
June 30, 2021	2,130	253	0.54	0.54
March 31, 2021	2,539	355	0.76	0.76

Generally, within each calendar year, quarterly results fluctuate in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the U.S. are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

Generally, from one calendar year to the next, quarterly results reflect: (i) continued organic growth driven by the Corporation's Capital Plan; (ii) any significant temperature fluctuations from seasonal norms; (iii) the timing and significance of any regulatory decisions; (iv) changes in the U.S.-to-Canadian dollar exchange rate; (v) for revenue, the flow through in customer rates of commodity costs; and (vi) for EPS, increases in the weighted average number of common shares outstanding.

December 2022/December 2021

See "Fourth Quarter Results" on page 38.

September 2022/September 2021

Common Equity Earnings increased by $31 million and basic EPS increased by $0.05 in comparison to the third quarter of 2021 due to: (i) Rate Base growth, mainly at ITC; (ii) higher retail electricity sales, transmission revenue and earnings associated with the Oso Grande generating facility in Arizona; (iii) higher earnings from the energy infrastructure segment mainly due to mark-to-market accounting of natural gas derivatives and higher hydroelectric production in Belize; and (iv) the impact of new customer rates and the timing of operating costs at Central Hudson.

Growth was tempered by the timing of expenses in Alberta and a favourable adjustment recognized in 2021 related to interest rate swaps at ITC. Results for the third quarter of 2022 were also impacted by significant items at ITC, including costs associated with the suspension of the Lake Erie Connector project, and the revaluation of deferred income tax assets due to a reduction in the corporate income tax rate in the state of Iowa. The impact of mark-to-market losses associated with hedging activities was more than offset by lower stock-based compensation costs and the translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

June 2022/June 2021

Common Equity Earnings increased by $31 million and basic EPS increased by $0.05 in comparison to the second quarter of 2021 due to: (i) Rate Base growth; (ii) higher earnings from the energy infrastructure segment, largely reflecting favourable changes in the mark-to-market accounting of natural gas derivatives at Aitken Creek; and (iii) a higher U.S.-to-Canadian dollar foreign exchange rate. Growth was partially offset by losses on investments that support retirement benefits at UNS Energy and ITC, reflecting market conditions, and the timing of quarterly earnings from Arizona and Alberta. In comparison to the second quarter of 2021, results from UNS Energy were tempered, as expected, by the timing of earnings related to the Oso Grande generating facility, and earnings from FortisAlberta were lower due to the timing of operating expenses. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

March 2022/March 2021

Common Equity Earnings decreased by $5 million and basic EPS decreased by $0.02 in comparison to the first quarter of 2021 due to higher unrealized losses of $14 million on the mark-to-market accounting of natural gas derivatives at Aitken Creek. Excluding this impact, the Corporation delivered earnings growth driven by Rate Base growth at ITC and the western Canadian utilities, and higher sales in the Caribbean. Growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Central Hudson mainly due to the costs of implementing a new CIS.

Earnings in Arizona were broadly consistent with the first quarter of 2021. The impact of higher electricity sales and lower planned generation maintenance costs was offset by the timing of earnings related to the Oso Grande generating facility, as expected. Losses on retirement investments also unfavourably impacted earnings at UNS Energy in the quarter.

The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2022 or 2021.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $37 million in 2022 (2021 - $38 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2022, accounts receivable included $7 million due from Belize Electricity (2021 - $22 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2022, there were no inter-segment loans outstanding (2021 - $126 million). Interest charged on inter-segment loans was not material in 2022 and 2021.

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP 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 U.S. securities laws. As of December 31, 2022, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and U.S. securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2022.

Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. Because of its inherent limitations, ICFR 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.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2022, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2022, the Corporation's ICFR was effective.

During the year ended December 31, 2022, there have been no changes in the Corporation's ICFR that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

Fortis continues to enhance shareholder value through the execution of its Capital Plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. While energy price volatility, global supply chain constraints and persistent inflation are issues of potential concern that continue to evolve, the Corporation does not currently expect there to be a material impact on its operations or financial results in 2023.

Fortis is executing on the transition to a cleaner energy future and is on track to achieve its corporate-wide targets to reduce GHG emissions by 50% by 2030 and 75% by 2035. Upon achieving this target, 99% of the Corporation's assets will support energy delivery and renewable, carbon-free generation. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to decarbonize over the long-term, while preserving customer reliability and affordability.

The Corporation's $22.3 billion five-year Capital Plan is expected to increase midyear Rate Base from $34.1 billion in 2022 to $46.1 billion by 2027, translating into a five-year CAGR of 6.2%.

Beyond the five-year Capital Plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the IRA and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2027. This dividend growth guidance will also provide flexibility to fund more capital with internally-generated funds and is premised on the assumptions and material factors listed under "Forward-Looking Information".

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2023-2027, including cleaner energy investments; forecast Rate Base and Rate Base growth for 2023 and through 2027; targeted annual dividend growth through 2027; the expectation that Fortis is well-positioned to capitalize on evolving industry opportunities, including additional investment opportunities beyond the Capital Plan; the expectation that volatility in energy prices, global supply chain constraints and persistent inflation will not have a material impact on operations or financial results in 2023 or the 2023-2027 capital plan; the 2030 GHG emissions reduction target; the 2035 GHG emissions reduction target and projected asset mix; the expectation to achieve the 2030 and 2035 GHG emissions reduction targets without the use of carbon offsets; the 2050 net-zero direct GHG emissions target and how that target is expected to be achieved; TEP's IRP and the expectation to exit coal by 2032; the expected timing, outcome and impact of regulatory proceedings and decisions; the expected or potential funding sources for operating expenses, interest costs and capital expenditures; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on the Corporation's ability to pay dividends in the foreseeable future; the expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have access to long-term capital and will remain compliant with debt covenants in 2023; the expected uses of proceeds from debt financings; the targeted capital structure; the nature, timing, benefits and expected costs of certain capital projects, including ITC's transmission projects associated with the MISO LRTP, renewable generation projects at UNS Energy, the Vail-to-Tortolita Transmission Project, the Tilbury LNG Storage Expansion, the AMI Project; the Eagle Mountain Woodfibre Gas Line Project, the Tilbury 1B Project, the Okanagan Capacity Upgrade, the Wataynikaneyap Transmission Power Project, and additional opportunities beyond the capital plan, including investments associated with the IRA, the MISO LRTP, TEP's IRP, climate adaptation and grid resiliency, and renewable gas solutions and LNG infrastructure in British Columbia; the expectation that the introduction of a corporate alternative minimum income tax will not have a material impact on financial results, Operating Cash Flow or credit ratings; the expectation that long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2027; and the expectation that the dividend growth guidance will provide flexibility to fund more capital internally.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information including, without limitation: no material impact from volatility in energy prices, global supply chain constraints and persistent inflation; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project or financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant operational disruptions or environmental liability or upset; the continued ability to maintain the performance of the electricity and gas systems; no severe and prolonged economic downturn; sufficient liquidity and capital resources; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; the continued availability of natural gas, fuel, coal and electricity supply; continuation of power supply and capacity purchase contracts; no significant changes in government energy plans, environmental laws and regulations that could have a material negative impact; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no significant changes in tax laws and the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; and favourable labour relations.

Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from those discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risks" in this MD&A and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2023 include, but are not limited to: uncertainty regarding changes in utility regulation, including the outcome of regulatory proceedings at the Corporation's utilities; the physical risks associated with the provision of electric and gas service, which are exacerbated by the impacts of climate change; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with cybersecurity and information and operations technology; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with commodity price volatility and supply of purchased power; and risks related to general economic conditions, including inflation, interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 9, 2023. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

GLOSSARY

2022 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2022

Actual Payout Ratio: dividends per common share divided by basic EPS

Adjusted Basic EPS: Adjusted Common Equity Earnings divided by the basic weighted average number of common shares outstanding

Adjusted Common Equity Earnings: net earnings attributable to common equity shareholders adjusted as shown under "Non-U.S. GAAP Financial Measures" on page 14

Adjusted Payout Ratio: dividends per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 14

AFUDC: allowance for funds used during construction

Aitken Creek: Aitken Creek Gas Storage ULC, a direct 93.8%-owned subsidiary of FortisBC Holdings Inc.

AMI: Advanced Metering Infrastructure

ACC: Arizona Corporation Commission

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

BECOL: Belize Electric Company Limited, an indirect wholly owned subsidiary of Fortis (now known as Fortis Belize)

Belize Electricity: Belize Electricity Limited, in which Fortis indirectly holds a 33% equity interest

Board: Board of Directors of the Corporation

CAGR(s): compound average growth rate of a particular item. CAGR = $(EV/BV)^{1-N}$ -1, where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) N is the number of periods. Calculated on a constant U.S. dollar to Canadian dollar exchange rate

Capital Expenditures: cash outlay for additions to property, plant and equipment and intangible assets as shown in the Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. See "Non-US GAAP Financial Measures" on page 14

Capital Plan: forecast Capital Expenditures. Represents a non-U.S. GAAP financial measure calculated in the same manner as Capital Expenditures

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2022) subsidiary of Fortis, together with its subsidiary

Central Hudson: CH Energy Group, Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries, including Central Hudson Gas & Electric Corporation

CEO: Chief Executive Officer of Fortis

CFO: Chief Financial Officer of Fortis

CIS: customer information system

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS: cost of service

COVID-19 Pandemic: declared by the World Health Organization in March 2020 as a result of a novel coronavirus

CPCN: Certificate of Public Convenience and Necessity

CRMP: Cybersecurity Risk Management Program

DBRS Morningstar: DBRS Limited

D.C. Circuit Court: U.S. Court of Appeals for the District of Columbia Circuit

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPRI: Electric Power Research Institute

EPS: earnings per common share

ERM: enterprise risk management

FERC: Federal Energy Regulatory Commission

Fortis: Fortis Inc.

FortisAlberta: FortisAlberta Inc., an indirect wholly owned subsidiary of Fortis

FortisBC Electric: FortisBC Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries

FortisBC Energy: FortisBC Energy Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries

FortisOntario: FortisOntario Inc., a direct wholly owned subsidiary of Fortis, together with its subsidiaries

FortisTCI: FortisTCI Limited, an indirect wholly owned subsidiary of Fortis, together with its subsidiary

Fortis Belize: Fortis Belize Limited, an indirect wholly owned subsidiary of Fortis (formerly known as BECOL)

Four Corners: Four Corners Generating Station, Units 4 and 5

FX: foreign exchange associated with the translation of U.S. dollar-denominated amounts. Foreign exchange is calculated by applying the change in the U.S.-to-Canadian dollar FX rates to the prior period U.S. dollar balance.

GCOC: generic cost of capital

GHG: greenhouse gas

GWh: gigawatt hour(s)

ICFR: internal control over financial reporting

ICAT: Iowa Coalition for Affordable Transmission

IRA: Inflation Reduction Act of 2022

IRP: Integrated Resource Plan

ITC: ITC Investment Holdings Inc., an indirect 80.1%-owned subsidiary of Fortis, together with its subsidiaries, including International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC

LNG: liquefied natural gas

LRTP: Long Range Transmission Plan

Luna: Luna Energy Facility

kV: kilovolt

Major Capital Projects: projects, other than ongoing maintenance projects, individually costing $200 million or more

Maritime Electric: Maritime Electric Company, Limited, an indirect wholly owned subsidiary of Fortis

Material Adverse Effect: a material adverse effect on the Corporation's business, results of operations, financial position or liquidity, on a consolidated basis

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2022

MISO: Midcontinent Independent System Operator, Inc.

Moody's: Moody's Investor Services, Inc.

MW: megawatt(s)

Navajo: Navajo Generating Station

Newfoundland Power: Newfoundland Power Inc., a direct wholly owned subsidiary of Fortis

Non-U.S. GAAP Financial Measures: financial measures that do not have a standardized meaning prescribed by U.S. GAAP

NOPR: notice of proposed rulemaking

NYSE: New York Stock Exchange

OEB: Ontario Energy Board

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

PSC: New York State Public Service Commission

Rate Base: the stated value of property on which a regulated utility is permitted to earn a specified return in accordance with its regulatory construct

REA: Rural Electrification Association

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

RTO: regional transmission organization

S&P: Standard & Poor's Financial Services LLC

San Juan: San Juan Generating Station Unit 1

SEDAR: Canadian System for Electronic Document Analysis and Retrieval

SOFR: Secured Overnight Financing Rate

TCFD: Task Force for Climate-Related Financial Disclosures

TEP: Tucson Electric Power Company, a direct wholly owned subsidiary of UNS Energy

TSR: total shareholder return, which is a measure of the return to common equity shareholders in the form of share price appreciation and dividends (assuming reinvestment) over a specified time period in relation to the share price at the beginning of the period.

TSX: Toronto Stock Exchange

UNS Energy: UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis, together with its subsidiaries, including TEP, UNS Electric, Inc. and UNS Gas, Inc.

U.S.: United States of America

U.S. GAAP: accounting principles generally accepted in the U.S.

Waneta Expansion: Waneta Expansion hydroelectric generation facility

Wataynikaneyap Partnership: Wataynikaneyap Power Limited Partnership

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2022 and 2021

Consolidated Financial Statements

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2022, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2022, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2022 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2022. Deloitte LLP issued an unqualified opinion for both audits.

February 9, 2023

/s/ David G. Hutchens

David G. Hutchens

President and Chief Executive Officer, Fortis Inc.
St. John's, Canada

/s/ Jocelyn H. Perry

Jocelyn H. Perry

Executive Vice President, Chief Financial Officer, Fortis Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2022 and 2021, the related consolidated statements of earnings, comprehensive income, cash flows, and changes in equity, for each of the two years in the period ended December 31, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2022, 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), the Corporation's internal control over financial reporting as of December 31, 2022, 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 9, 2023, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Corporation'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 the Corporation 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 audit 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 opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment for Impairment of Goodwill - Refer to Notes 3 and 12 to the financial statements

Critical Audit Matter Description

The Corporation assesses goodwill for impairment annually as well as whenever any event or other change indicates that the fair value of a reporting unit may be below its carrying value. Management has determined that there is no impairment based on its current annual assessment.

Management's assessment primarily utilizes the income approach which is based on underlying estimates and assumptions with varying degrees of uncertainty. Those with the highest degree of subjectivity and impact are the assumed terminal growth rates and discount rates. Auditing these estimates and assumptions required a high degree of audit judgment and effort, including the need to involve a fair value specialist.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the terminal growth rate and discount rate used by management to estimate the fair value of more recently acquired reporting units included the following:

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the terminal growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the terminal growth rate by:
  - Assessing the methodology used in management's determination of the terminal growth rate; and
  - Comparing management's assumptions to historical data and available market trends.
- With the assistance of a fair value specialist, evaluating the reasonableness of the discount rate by:
  - Testing the source information underlying the determination of the discount rate; and
  - Developing a range of independent estimates and comparing those to the discount rate selected by management.

Impact of Rate Regulation on the financial statements - Refer to Notes 2, 3 and 8 to the financial statements

Critical Audit Matter Description

The Corporation's regulated utilities are subject to rate regulation and annual earnings oversight by various federal, state and provincial regulatory authorities who have jurisdiction in the United States and Canada. Rates and resultant earnings of the Corporation's regulated utilities are determined under cost of service regulation, with some using performance-based rate-setting mechanisms. The regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on asset value ("ROA") or common shareholders' equity ("ROE"). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE and/or ROA. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation's regulated utilities have indicated they expect to recover costs from customers through regulated rates, there is a risk that the respective regulatory authority will not approve full recovery of the costs incurred and a reasonable ROE and/or ROA. Auditing these matters required especially subjective judgment and specialized knowledge of accounting for rate regulation due to its inherent complexities across different jurisdictions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information to evaluate the likelihood of recovery in future rates or of a future reduction in rates and the ability to earn a reasonable ROA or ROE.
- For regulatory matters in progress, inspecting the regulated utilities' filings for any evidence that might contradict management's assertions. We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 9, 2023

We have served as the Corporation's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2022, 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 Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, 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, 2022, of the Corporation and our report dated February 9, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment 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 an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit provides a reasonable basis for our opinion.

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.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 9, 2023

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2022**	2021
ASSETS		
Current assets		
Cash and cash equivalents	**$ 209**	$ 131
Accounts receivable and other current assets (Note 6)	**2,339**	1,511
Prepaid expenses	**146**	116
Inventories (Note 7)	**661**	478
Regulatory assets (Note 8)	**914**	492
Total current assets	**4,269**	2,728
Other assets (Note 9)	**1,213**	955
Regulatory assets (Note 8)	**3,095**	3,097
Property, plant and equipment, net (Note 10)	**41,663**	37,816
Intangible assets, net (Note 11)	**1,548**	1,343
Goodwill (Note 12)	**12,464**	11,720
Total assets	**$ 64,252**	$ 57,659
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 253**	$ 247
Accounts payable and other current liabilities (Note 13)	**3,288**	2,570
Regulatory liabilities (Note 8)	**595**	357
Current installments of long-term debt (Note 14)	**2,481**	1,628
Total current liabilities	**6,617**	4,802
Regulatory liabilities (Note 8)	**3,320**	2,865
Deferred income taxes (Note 22)	**4,060**	3,627
Long-term debt (Note 14)	**25,931**	23,707
Finance leases (Note 15)	**336**	333
Other liabilities (Note 16)	**1,146**	1,409
Total liabilities	**41,410**	36,743
Commitments and contingencies (Note 26)		
Equity		
Common shares (1)	**14,656**	14,237
Preference shares (Note 18)	**1,623**	1,623
Additional paid-in capital	**10**	10
Accumulated other comprehensive income (loss) (Note 19)	**1,008**	(40)
Retained earnings	**3,733**	3,458
Shareholders' equity	**21,030**	19,288
Non-controlling interests	**1,812**	1,628
Total equity	**22,842**	20,916
Total liabilities and equity	**$ 64,252**	$ 57,659

(1) No par value. Unlimited authorized shares. 482.2 million and 474.8 million issued and outstanding as at December 31, 2022 and 2021, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel
Jo Mark Zurel,
Director

/s/ Maura J. Clark
Maura J. Clark,
Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)		**2022**		2021
Revenue (Note 5)	**$**	**11,043**	$	9,448
Expenses				
Energy supply costs		**3,952**		2,951
Operating expenses		**2,683**		2,523
Depreciation and amortization		**1,668**		1,505
Total expenses		**8,303**		6,979
Operating income		**2,740**		2,469
Other income, net (Note 21)		**165**		173
Finance charges		**1,102**		1,003
Earnings before income tax expense		**1,803**		1,639
Income tax expense (Note 22)		**289**		234
Net earnings	**$**	**1,514**	$	1,405
Net earnings attributable to:				
Non-controlling interests	**$**	**120**	$	111
Preference equity shareholders		**64**		63
Common equity shareholders		**1,330**		1,231
	$	**1,514**	$	1,405
Earnings per common share (Note 17)				
Basic	**$**	**2.78**	$	2.61
Diluted	**$**	**2.78**	$	2.61

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)		**2022**		2021
Net earnings	**$**	**1,514**	$	1,405
Other comprehensive income (loss)				
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $15 million and $(2) million, respectively		**1,100**		(93)
Other, net of income tax expense of $21 million and $3 million, respectively		**73**		8
		1,173		(85)
Comprehensive income	**$**	**2,687**	$	1,320
Comprehensive income attributable to:				
Non-controlling interests	**$**	**245**	$	100
Preference equity shareholders		**64**		63
Common equity shareholders		**2,378**		1,157
	$	**2,687**	$	1,320

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the year ended December 31 (in millions of Canadian dollars)	**2022**	2021
Operating activities		
Net earnings	**$ 1,514**	$ 1,405
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,460**	1,313
Amortization - intangible assets	**145**	136
Amortization - other	**63**	56
Deferred income tax expense (Note 22)	**182**	147
Equity component, allowance for funds used during construction (Note 21)	**(78)**	(77)
Other	**105**	75
Change in long-term regulatory assets and liabilities	**162**	(4)
Change in working capital (Note 24)	**(479)**	(144)
Cash from operating activities	**3,074**	2,907
Investing activities		
Additions to property, plant and equipment	**(3,587)**	(3,189)
Additions to intangible assets	**(278)**	(197)
Contributions in aid of construction	**111**	93
Contributions to equity-accounted investees	**(100)**	—
Other	**(205)**	(195)
Cash used in investing activities	**(4,059)**	(3,488)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,067**	1,324
Repayments of long-term debt and finance leases	**(1,526)**	(634)
Borrowings under committed credit facilities	**6,651**	5,082
Repayments under committed credit facilities	**(6,381)**	(4,749)
Net change in short-term borrowings	**(21)**	115
Issue of common shares, net of costs, and dividends reinvested	**53**	60
Dividends		
Common shares, net of dividends reinvested	**(673)**	(608)
Preference shares	**(64)**	(63)
Subsidiary dividends paid to non-controlling interests	**(66)**	(58)
Other	**(5)**	(18)
Cash from financing activities	**1,035**	451
Effect of exchange rate changes on cash and cash equivalents	**28**	12
Change in cash and cash equivalents	**78**	(118)
Cash and cash equivalents, beginning of year	**131**	249
Cash and cash equivalents, end of year	**$ 209**	$ 131

Supplementary Cash Flow Information (Note 24)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(# millions)*	**Common Shares**	**Preference Shares** (Note 18)	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** (Note 19)	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2021	**474.8**	**$ 14,237**	**$ 1,623**	**$ 10**	**$ (40)**	**$ 3,458**	**$ 1,628**	**$ 20,916**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,394**	**120**	**1,514**
Other comprehensive income	**—**	**—**	**—**	**—**	**1,048**	**—**	**125**	**1,173**
Common shares issued	**7.4**	**419**	**—**	**(2)**	**—**	**—**	**—**	**417**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(66)**	**(66)**
Dividends declared on common shares ($2.20 per share)	**—**	**—**	**—**	**—**	**—**	**(1,055)**	**—**	**(1,055)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(64)**	**—**	**(64)**
Other	**—**	**—**	**—**	**2**	**—**	**—**	**5**	**7**
As at December 31, 2022	**482.2**	**$ 14,656**	**$ 1,623**	**$ 10**	**$ 1,008**	**$ 3,733**	**$ 1,812**	**$ 22,842**
As at December 31, 2020	466.8	$ 13,819	$ 1,623	$ 11	$ 34	$ 3,210	$ 1,587	$ 20,284
Net earnings	—	—	—	—	—	1,294	111	1,405
Other comprehensive loss	—	—	—	—	(74)	—	(11)	(85)
Common shares issued	8.0	418	—	(2)	—	—	—	416
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(58)	(58)
Dividends declared on common shares ($2.08 per share)	—	—	—	—	—	(983)	—	(983)
Dividends on preference shares	—	—	—	—	—	(63)	—	(63)
Other	—	—	—	1	—	—	(1)	—
As at December 31, 2021	474.8	$ 14,237	$ 1,623	$ 10	$ (40)	$ 3,458	$ 1,628	$ 20,916

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is a well-diversified North American regulated electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: ITC Investment Holdings Inc., ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma. ITC also has electric transmission system assets under construction in Wisconsin.

UNS Energy: UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,328 megawatts ("MW"), including 68 MW of solar capacity and 250 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson: CH Energy Group, Inc., which primarily includes Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 65 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, provides transmission and distribution services in over 135 communities. FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. It is not involved in the direct sale of electricity.

FortisBC Electric: FortisBC Inc. is an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia that are owned by third parties.

Other Electric: Eastern Canadian and Caribbean utilities, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("Belize Electricity").

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 143 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 90 MW. FortisOntario consists of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 5 MW. Wataynikaneyap Partnership is a partnership between 24 First Nations communities, Fortis and Algonquin Power & Utilities Corp. with a mandate to connect remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 166 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a generating capacity of 86 MW, including 84 MW of diesel-powered generating capacity and 2 MW of solar capacity. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

1. DESCRIPTION OF BUSINESS (cont'd)

Non-Regulated

Energy Infrastructure: Long-term contracted generation assets in Belize and the Aitken Creek natural gas storage facility ("Aitken Creek") in British Columbia. Generation assets in Belize consist of three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Fortis Belize Limited (formerly known as Belize Electric Company Limited). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

Corporate and Other: Captures expenses and revenues not specifically related to any reportable segment and those business operations that are below the required threshold for segmented reporting, including net corporate expenses of Fortis and non-regulated holding company expenses.

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

2. REGULATION (cont'd)

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE (1) (%)		Significant Features
			2022	2021	
ITC (2)	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.77	Cost-based formula rates, with annual true-up mechanism (3) Incentive adders
TEP	Arizona Corporation Commission ("ACC") (4)	53.0	**9.15**	9.15	COS regulation Historical test year
	FERC	(5)	**9.79**	9.79	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson (6)	New York State Public Service Commission ("PSC")	49.0	**9.00**	9.00	COS regulation Future test year
FortisBC Energy (7)	British Columbia Utilities Commission ("BCUC")	38.5	**8.75**	8.75	COS regulation with formula components and incentives (8)
FortisBC Electric (7)	BCUC	40.0	**9.15**	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**8.50**	8.50	PBR (9)
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.50**	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	**9.35**	9.35	COS regulation Future test year
FortisOntario (10)	Ontario Energy Board	40.0	**8.52-9.30**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities (11)	Utility Regulation and Competition Office	N/A	**6.25-8.25**	6.00-8.00	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI (12)	Government of the Turks and Caicos Islands	N/A	**15.00-17.50**	15.00-17.50	COS regulation Historical test year

(1) *ROA for Caribbean Utilities and FortisTCI*

(2) *Includes the allowed common equity and base ROE plus incentive adders for ITCTransmission, METC, and ITC Midwest. See "Significant Regulatory Developments" below*

(3) *Annual true-up collected or refunded in rates within a two-year period*

(4) *Approved ROE of 9.15% with a 0.20% return on the fair value increment. A general rate application requesting new rates effective September 1, 2023 is ongoing. See "Significant Regulatory Developments" below*

(5) *The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio*

(6) *Effective July 1, 2021 Central Hudson's approved common equity component of capital structure was 50%, declining by 1% annually to 48% in the third rate year*

(7) *A generic cost of capital ("GCOC") proceeding is ongoing. See "Significant Developments" below*

(8) *Formula and incentives have been set through 2024*

(9) *FortisAlberta is subject to PBR including mechanisms for flow-through costs and capital expenditures not otherwise recovered through customer rates. FortisAlberta's current PBR term expired as of December 31, 2022. See "Significant Regulatory Developments" below*

(10) *Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033*

(11) *Operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039*

(12) *Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037*

Significant Regulatory Developments

ITC

ITC Midwest Capital Structure Complaint: In May 2022, the Iowa Coalition for Affordable Transmission ("ICAT") filed a complaint with FERC under Section 206 of the Federal Power Act requesting that ITC Midwest's common equity component of capital structure be reduced from 60% to 53%. ICAT alleged that ITC Midwest does not meet FERC's three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In November 2022, FERC issued an order denying the complaint, and in December 2022, ICAT filed a request for rehearing with FERC. As at December 31, 2022, ITC Midwest has not recorded a regulatory liability related to the complaint.

2. REGULATION (cont'd)

MISO Base ROE: In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the Midcontinent Independent System Operator, Inc. ("MISO") region, including ITC. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect. The court has remanded the matter to FERC for further process, the timing and outcome of which is unknown.

Transmission Incentives: In 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding is unknown.

UNS Energy

TEP General Rate Application: In June 2022, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2023 using a December 31, 2021 test year. The application reflects a US$136 million net increase in non-fuel and fuel-related revenue, as well as proposals to eliminate certain adjustor mechanisms, and modify an existing adjustor to provide more timely recovery of clean energy investments. The timing and outcome of this proceeding is unknown.

Central Hudson

Customer Information System ("CIS") Implementation: In December 2022, the PSC released a report into the deployment by Central Hudson of its new CIS. The PSC also issued an Order to Commence Proceeding and Show Cause, which directed Central Hudson to explain why the PSC should not pursue civil or administrative penalties or initiate a proceeding to review the prudence of the CIS implementation costs. Central Hudson was also required to submit a plan to eliminate bi-monthly bill estimates and to evaluate the customer impacts of such a change. Central Hudson's response was filed in January 2023. The timing and outcome of this proceeding is unknown.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In 2021, the BCUC initiated a proceeding including a review of the common equity component of capital structure and the allowed ROE. FortisBC filed a final argument with the BCUC in December 2022 and the proceeding remains ongoing, with a decision expected in the second quarter of 2023.

FortisAlberta

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for Alberta regulated utilities for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. In March 2022, the AUC issued a decision extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. The GCOC proceeding for 2024 and beyond remains ongoing, and a decision is expected in the third quarter of 2023.

2023 COS Application: In July 2022, the AUC issued a decision largely accepting the forecast requested in FortisAlberta's COS application. The associated compliance filing, including the updated 2023 revenue requirement, was approved by the AUC in December 2022.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta is participating in this proceeding and a decision from the AUC is expected in 2023.

Rural Electrification Association ("REA") Cost Recovery: In 2021, the AUC determined that costs attributable to REAs, approximating $10 million annually, can no longer be recovered from FortisAlberta's rate payers, effective January 1, 2023. FortisAlberta filed an appeal with the Alberta Court of Appeal, asserting that the AUC erred in preventing the company from recovering these costs from its own rate payers to the extent that such costs cannot be recovered directly from REAs. The appeal was heard in December 2022, and a decision from the Court is expected in first quarter of 2023.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with U.S. GAAP for rate-regulated entities.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts, and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Credit Losses

Fortis and its subsidiaries recognize an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and net realizable value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the utility rate-setting process and are subject to regulatory approval. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments are reviewed annually for potential impairment in value. Impairments are recognized when identified.

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual removal costs are netted when incurred.

The Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized.

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2022 totalled $45 million (2021 - $39 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 21). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

Excluding UNS Energy and Central Hudson, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulators, UNS Energy and Central Hudson recognize such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators and ranged from 0.5% to 39.8% for 2022 (2021 - 0.9% to 39.8%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2022 (2021 – 2.6%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

The service life ranges and weighted average remaining service life of PPE as at December 31 were as follows.

	2022		2021	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**31**	5-80	32
Gas	**18-95**	**39**	18-95	38
Transmission				
Electric	**20-90**	**41**	20-90	42
Gas	**10-85**	**35**	10-85	35
Generation	**5-95**	**22**	5-95	23
Other	**3-80**	**11**	3-70	13

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 33.0% for 2022 (2021 – 1.0% to 33.0%).

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2022		2021	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**5**	3-15	4
Land, transmission and water rights	**34-90**	**54**	34-90	55
Other	**10-100**	**11**	10-100	11

The Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the total undiscounted cash flows expected to be generated by the asset may be below carrying value. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Goodwill at each of the Corporation's 11 reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit, and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Deferred Financing Costs

Issue costs, discounts and premiums are recognized against, and amortized over the life of, the related long-term debt.

Employee Future Benefits

Fortis and each subsidiary maintain one or a combination of defined benefit pension plans and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The costs of defined contribution pension plans are expensed as incurred.

For defined benefit pension and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

Defined benefit pension and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of: (i) the projected or accumulated benefit obligation; and (ii) the fair value or market-related value, as applicable, of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension and OPEB plans, measured as the difference between the fair value of the plan assets and the projected or accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheets.

For most of the Corporation's regulated utilities, any difference between defined benefit pension or OPEB plan costs ordinarily recognized under U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates. In addition, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8).

Leases

A right-of-use asset and lease liability is recognized for leases with a lease term greater than 12 months. The right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

Finance leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

Revenue Recognition

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Energy sales are generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the Alberta Electric System Operator. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is probable.

Revenue excludes sales and municipal taxes collected from customers.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Revenue Recognition (cont'd)

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment is less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Stock-Based Compensation

Effective January 1, 2022, stock options have been excluded from the Corporation's long-term incentive mix. Compensation expense related to stock options granted in 2021 or prior were measured at the grant date using the Black-Scholes fair value option-pricing model with each grant amortized to compensation expense evenly over the four-year vesting period, with the offsetting entry to additional paid-in capital. Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

Fortis recognizes liabilities associated with its directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans. DSUs and PSUs, represent cash-settled awards whereas RSU's represent cash or share-settled awards, depending on settlement elections and the share ownership requirements of the executive. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2022 was $54.65 (2021 - $61.08). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a U.S. dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2022 was US$1.00=CA$1.36 (2021 – US$1.00=CA$1.26).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CA$1.30 for 2022 (2021 - US$1.00=CA$1.25).

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Translation gains and losses are recognized in earnings.

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

Derivatives Designated as Hedges

Fortis, ITC and UNS Energy use cash flow hedges, from time to time, to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and certain equity-accounted investments are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through U.S. dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Derivatives and Hedging (cont'd)

Presentation of Derivatives

The fair value of derivatives is recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

Deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are "more likely than not" to be realized. They are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change occurs. Valuation allowances are recognized when it is "more likely than not" that all of, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and Fortis Belize are not subject to income tax.

Differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 8).

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $5.3 billion as at December 31, 2022 (2021 - $4.1 billion). If such earnings are repatriated, the Corporation 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 impractical.

Tax benefits associated with actual or expected income tax positions are recognized when the "more likely than not" recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, rights-of-way and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 16) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Accretion and depreciation expense are deferred as a regulatory asset or liability based on regulatory recovery of these costs. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are subject to various legal proceedings and claims that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long periods of time. Actual outcomes may differ materially from the amounts recognized.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

Future Accounting Pronouncements

The Corporation considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board. Any ASUs not included in these consolidated financial statements were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

4. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by its CEO in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders.

Related-Party and Inter-Company Transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2022 or 2021.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $37 million in 2022 (2021 - $38 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2022, accounts receivable included $7 million due from Belize Electricity (2021 - $22 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2022, there were no inter-segment loans outstanding (2021 - $126 million). Interest charged on inter-segment loans was not material in 2022 and 2021.

4. SEGMENTED INFORMATION (cont'd)

	Regulated								Non-Regulated			
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub-total**	**Energy Infra-structure**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Year ended December 31, 2022												
Revenue	1,906	2,758	1,325	2,084	680	487	1,652	**10,892**	**151**	**—**	**—**	**11,043**
Energy supply costs	—	1,213	525	1,055	—	141	1,013	**3,947**	**5**	**—**	**—**	**3,952**
Operating expenses	481	691	571	364	166	133	217	**2,623**	**40**	**20**	**—**	**2,683**
Depreciation and amortization	385	365	104	298	243	67	187	**1,649**	**17**	**2**	**—**	**1,668**
Operating income	1,040	489	125	367	271	146	235	**2,673**	**89**	**(22)**	**—**	**2,740**
Other income, net	48	22	59	22	5	6	14	**176**	**1**	**(12)**	**—**	**165**
Finance charges	349	127	53	146	110	76	75	**936**	**—**	**166**	**—**	**1,102**
Income tax expense	184	56	28	39	15	12	22	**356**	**18**	**(85)**	**—**	**289**
Net earnings	555	328	103	204	151	64	152	**1,557**	**72**	**(115)**	**—**	**1,514**
Non-controlling interests	101	—	—	1	—	—	18	**120**	**—**	**—**	**—**	**120**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**64**	**—**	**64**
Net earnings attributable to common equity shareholders	454	328	103	203	151	64	134	**1,437**	**72**	**(179)**	**—**	**1,330**
Additions to property, plant and equipment and intangible assets	1,212	709	293	589	510	130	393	**3,836**	**29**	**—**	**—**	**3,865**
As at December 31, 2022												
Goodwill	8,318	1,873	612	913	228	235	258	**12,437**	**27**	**—**	**—**	**12,464**
Total assets	23,478	12,678	5,131	8,875	5,547	2,596	4,916	**63,221**	**884**	**159**	**(12)**	**64,252**
Year ended December 31, 2021												
Revenue	1,691	2,334	1,000	1,715	644	468	1,498	9,350	98	—	—	9,448
Energy supply costs	—	919	285	713	—	136	895	2,948	3	—	—	2,951
Operating expenses	466	648	498	355	157	128	201	2,453	33	37	—	2,523
Depreciation and amortization	291	345	91	281	231	65	181	1,485	17	3	—	1,505
Operating income	934	422	126	366	256	139	221	2,464	45	(40)	—	2,469
Other income, net	42	41	34	12	2	5	5	141	1	31	—	173
Finance charges	300	120	46	144	106	73	71	860	—	143	—	1,003
Income tax expense	156	51	21	48	11	12	21	320	8	(94)	—	234
Net earnings	520	292	93	186	141	59	134	1,425	38	(58)	—	1,405
Non-controlling interests	94	—	—	1	—	—	16	111	—	—	—	111
Preference share dividends	—	—	—	—	—	—	—	—	—	63	—	63
Net earnings attributable to common equity shareholders	426	292	93	185	141	59	118	1,314	38	(121)	—	1,231
Additions to property, plant and equipment and intangible assets	1,046	710	291	475	389	134	321	3,366	20	—	—	3,386
As at December 31, 2021												
Goodwill	7,755	1,746	570	913	228	235	246	11,693	27	—	—	11,720
Total assets	21,020	11,126	4,356	8,135	5,201	2,540	4,357	56,735	777	295	(148)	57,659

5. REVENUE

($ millions)	**2022**	2021
Electric and gas revenue		
United States		
ITC	**1,911**	1,694
UNS Energy	**2,498**	2,071
Central Hudson	**1,307**	962
Canada		
FortisBC Energy	**2,080**	1,645
FortisAlberta	**655**	622
FortisBC Electric	**429**	404
Newfoundland Power	**722**	701
Maritime Electric	**234**	223
FortisOntario	**220**	211
Caribbean		
Caribbean Utilities	**349**	248
FortisTCI	**98**	89
Total electric and gas revenue	**10,503**	8,870
Other services revenue [1]	**409**	382
Revenue from contracts with customers	**10,912**	9,252
Alternative revenue	**(28)**	(18)
Other revenue	**159**	214
Total revenue	**11,043**	9,448

[1] *Includes $266 million and $260 million from regulated operations for 2022 and 2021, respectively*

Revenue from Contracts with Customers

Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates including the flow through of commodity costs.

Other services revenue includes: (i) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (ii) revenue from storage optimization activities at Aitken Creek; and (iii) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability. The significant alternative revenue programs of Fortis' utilities are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period (Note 8). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of total retail revenue. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE. This mechanism is in place until the expiry of the current multi-year rate plan in 2024. Additionally, variances between forecast and actual customer-use rates and industrial and other customer revenue are captured in a revenue stabilization account and a flow-through deferral account, respectively, to be refunded to, or received from, customers in rates within two years.

Other Revenue

Other revenue primarily includes gains or losses on energy contract derivatives, as well as regulatory deferrals at FortisBC Energy and FortisBC Electric reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2022**	2021
Trade accounts receivable	**930**	621
Unbilled accounts receivable	**887**	701
Allowance for credit losses	**(58)**	(53)
	1,759	1,269
Other [1]	**580**	242
	2,339	1,511

[1] *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 25)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2022**	2021
Balance, beginning of year	**(53)**	(64)
Credit loss expensed	**(27)**	(7)
Credit loss deferral	**(6)**	—
Write-offs, net of recoveries	**30**	18
Foreign exchange	**(2)**	—
Balance, end of year	**(58)**	(53)

See Note 25 for disclosure on the Corporation's credit risk.

7. INVENTORIES

($ millions)	**2022**	2021
Materials and supplies	**394**	318
Gas and fuel in storage	**235**	131
Coal inventory	**32**	29
	661	478

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2022**	2021
Regulatory assets		
Deferred income taxes (Note 3)	**1,874**	1,806
Rate stabilization and related accounts [1]	**557**	339
Deferred energy management costs [2]	**445**	384
Employee future benefits (Notes 3 and 23)	**207**	388
Deferred lease costs [3]	**132**	127
Manufactured gas plant site remediation deferral (Note 16)	**97**	96
Deferred restoration costs [4]	**91**	17
Derivatives (Notes 3 and 25)	**84**	20
Generation early retirement costs [5]	**78**	48
Other regulatory assets [6]	**444**	364
Total regulatory assets	**4,009**	3,589
Less: Current portion	**(914)**	(492)
Long-term regulatory assets	**3,095**	3,097

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

($ millions)	**2022**	2021
Regulatory liabilities		
Deferred income taxes (Note 3)	**1,364**	1,289
Future cost of removal (Note 3)	**1,306**	1,217
Employee future benefits (Notes 3 and 23)	**306**	196
Rate stabilization and related accounts (1)	**297**	116
Derivatives (Notes 3 and 25)	**224**	52
Renewable energy surcharge (7)	**126**	107
Energy efficiency liability (8)	**89**	83
Other regulatory liabilities (6)	**203**	162
Total regulatory liabilities	**3,915**	3,222
Less: Current portion	**(595)**	(357)
Long-term regulatory liabilities	**3,320**	2,865

(1) ***Rate Stabilization and Related Accounts:*** Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact of reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 5).

(2) ***Deferred Energy Management Costs:*** Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from one to 10 years.

(3) ***Deferred Lease Costs:*** Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 15). The depreciation of the asset under finance lease and interest expense on the finance lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under the BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(4) ***Deferred Restoration Costs:*** Incremental costs incurred at Central Hudson and Maritime Electric associated with restoration activities due to significant weather events. Incremental costs incurred in excess of that collected in customer rates at Central Hudson are recovered through rate stabilization accounts. The form and recovery period for Maritime Electric will be determined by the regulator.

(5) ***Generation Early Retirement Costs:*** Includes costs at TEP associated with the retirement of the Navajo Generating Station ("Navajo") and Sundt Generating Facility Units 1 and 2 in 2019 and the San Juan Generating Station ("San Juan") in 2022, as approved for recovery by its regulator.

(6) ***Other Regulatory Assets and Liabilities:*** Comprised of regulatory assets and liabilities individually less than $40 million.

(7) ***Renewable Energy Surcharge:*** Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through a RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("RECs"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 9) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are utilized for RES compliance, energy supply costs and revenue are recognized in an equal amount.

(8) ***Energy Efficiency Liability:*** The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

Regulatory assets not earning a return: (i) totalled $1,980 million and $1,727 million as at December 31, 2022 and 2021, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

($ millions)	**2022**	2021
Employee future benefits (Note 23)	**274**	259
Equity investments [(1)]	**201**	92
Supplemental Executive Retirement Plan ("SERP")	**155**	165
RECs (Note 8)	**142**	112
Derivatives	**118**	40
Other investments	**115**	86
Operating leases (Note 15)	**43**	40
Deferred compensation plan	**40**	42
Other	**125**	119
	1,213	955

[(1)] *Includes investments in Belize Electricity and Wataynikaneyap Partnership*

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 25).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2022			
Distribution			
Electric	**13,650**	**(3,715)**	**9,935**
Gas	**6,396**	**(1,626)**	**4,770**
Transmission			
Electric	**19,056**	**(4,074)**	**14,982**
Gas	**2,600**	**(800)**	**1,800**
Generation	**7,173**	**(2,679)**	**4,494**
Other	**4,803**	**(1,610)**	**3,193**
Assets under construction	**2,094**	**—**	**2,094**
Land	**395**	**—**	**395**
	56,167	**(14,504)**	**41,663**
2021			
Distribution			
Electric	12,321	(3,359)	8,962
Gas	5,838	(1,504)	4,334
Transmission			
Electric	17,104	(3,610)	13,494
Gas	2,453	(756)	1,697
Generation	7,014	(2,691)	4,323
Other	4,362	(1,454)	2,908
Assets under construction	1,759	—	1,759
Land	339	—	339
	51,190	(13,374)	37,816

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems, wind resources and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, information technology assets and assets associated with natural gas storage at Aitken Creek.

As at December 31, 2022, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy.

The cost of PPE under finance lease as at December 31, 2022 was $323 million (2021 - $323 million) and related accumulated depreciation was $117 million (2021 - $113 million) (Note 15).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2022, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	Various	**1,333**	**(428)**	**905**
Springerville Common Facilities	86.0	**544**	**(294)**	**250**
Springerville Coal Handling Facilities	83.0	**281**	**(133)**	**148**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**264**	**(119)**	**145**
Gila River Common Facilities	50.0	**118**	**(43)**	**75**
Luna Energy Facility ("Luna")	33.3	**77**	**—**	**77**
		2,617	**(1,017)**	**1,600**

11. INTANGIBLE ASSETS

($ millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
2022			
Computer software	**985**	**(497)**	**488**
Land, transmission and water rights	**1,064**	**(171)**	**893**
Other	**135**	**(78)**	**57**
Assets under construction	**110**	**—**	**110**
	2,294	**(746)**	**1,548**
2021			
Computer software	952	(518)	434
Land, transmission and water rights	941	(154)	787
Other	113	(69)	44
Assets under construction	78	—	78
	2,084	(741)	1,343

Included in the cost of land, transmission and water rights as at December 31, 2022 was $117 million (2021 - $137 million) not subject to amortization. Amortization expense was $145 million for 2022 (2021 - $136 million). Amortization is estimated to average approximately $90 million for each of the next five years.

12. GOODWILL

($ millions)	**2022**	2021
Balance, beginning of year	**11,720**	11,792
Foreign currency translation impacts [1]	**744**	(72)
Balance, end of year	**12,464**	11,720

[1] *Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the U.S. dollar*

No goodwill impairment was recognized by the Corporation in 2022 or 2021.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2022**	2021
Trade accounts payable	**886**	774
Gas and fuel cost payable	**512**	269
Customer and other deposits	**401**	288
Accrued taxes other than income taxes	**282**	238
Dividends payable	**278**	259
Employee compensation and benefits payable	**270**	283
Interest payable	**254**	218
Derivatives (Note 25)	**127**	43
Income taxes payable	**88**	31
Employee future benefits (Note 23)	**28**	26
Manufactured gas plant site remediation (Note 16)	**17**	13
Other	**145**	128
	3,288	2,570

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2022**	2021
ITC			
Secured U.S. First Mortgage Bonds - 4.22% weighted average fixed rate (2021 - 4.31%)	2024-2055	**3,344**	2,736
Secured U.S. Senior Notes - 3.83% weighted average fixed rate (2021 - 3.90%)	2040-2055	**1,186**	1,011
Unsecured U.S. Senior Notes - 3.98% weighted average fixed rate (2021 - 3.61%)	2023-2043	**4,541**	4,108
Unsecured U.S. Shareholder Note - 6.00% fixed rate (2021 - 6.00%)	2028	**270**	252
UNS Energy			
Unsecured U.S. Tax-Exempt Bond - 4.00% weighted average fixed rate (2021 - 4.34%)	2029	**123**	359
Unsecured U.S. Fixed Rate Notes - 3.58% weighted average fixed rate (2021 - 3.62%)	2023-2052	**3,450**	2,780
Central Hudson			
Unsecured U.S. Promissory Notes - 4.14% weighted average fixed and variable rate (2021 - 3.83%)	2024-2060	**1,526**	1,177
FortisBC Energy			
Unsecured Debentures - 4.61% weighted average fixed rate (2021 - 4.61%)	2026-2052	**3,295**	3,145
FortisAlberta			
Unsecured Debentures - 4.49% weighted average fixed rate (2021 - 4.49%)	2024-2052	**2,485**	2,360
FortisBC Electric			
Secured Debentures - 8.80% fixed rate (2021 - 8.80%)	2023	**25**	25
Unsecured Debentures - 4.70% weighted average fixed rate (2021 - 4.77%)	2035-2052	**860**	760
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.26% weighted average fixed rate (2021 - 5.61%)	2026-2060	**666**	627
Secured First Mortgage Bonds - 5.31% weighted average fixed rate (2021 - 5.31%)	2025-2061	**260**	260
Unsecured Senior Notes - 4.45% weighted average fixed rate (2021 - 4.45%)	2041-2048	**152**	152
Unsecured U.S. Senior Loan Notes and Bonds - 4.71% weighted average fixed and variable rate (2021 - 4.36%)	2023-2052	**745**	609
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes - 3.82% weighted average fixed rate (2021 - 3.82%)	2023-2044	**2,691**	2,509
Unsecured Debentures - 6.51% fixed rate (2021 - 6.51%)	2039	**200**	200
Unsecured Senior Notes - 3.31% weighted average fixed rate (2021 - 2.52%)	2028-2029	**1,000**	1,000
Long-term classification of credit facility borrowings		**1,657**	1,305
Fair value adjustment - ITC acquisition		**102**	107
Total long-term debt (Note 25)		**28,578**	25,482
Less: Deferred financing costs and debt discounts		**(166)**	(147)
Less: Current installments of long-term debt		**(2,481)**	(1,628)
		25,931	23,707

14. LONG-TERM DEBT (cont'd)

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt agreements have covenants that provide that the Corporation shall not declare, pay or make any restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances in 2022	**Month Issued**	**Interest Rate** *(%)*	**Maturity**	**Amount** *($ millions)*	**Use of Proceeds**
ITC					
Secured first mortgage bonds	January	2.93	2052	**US 150**	(1) (2) (3) (4)
Secured senior notes	May	3.05	2052	**US 75**	(1) (3) (4)
Unsecured senior notes	September	4.95 (5)	2027	**US 600**	(1) (4) (6)
Secured first mortgage bonds	October	3.87	2027	**US 75**	(2)
Secured first mortgage bonds	October	4.53	2052	**US 75**	(2)
UNS Energy					
Unsecured senior notes	February	3.25	2032	**US 325**	(4) (6)
Central Hudson					
Unsecured senior notes	January	2.37	2027	**US 50**	(4) (6)
Unsecured senior notes	January	2.59	2029	**US 60**	(4) (6)
Unsecured senior notes	September	5.07	2032	**US 100**	(1) (4)
Unsecured senior notes	September	5.42	2052	**US 10**	(1) (4)
FortisBC Energy					
Unsecured debentures	November	4.67	2052	**150**	(2)
FortisAlberta					
Senior unsecured debentures	May	4.62	2052	**125**	(1)
FortisBC Electric					
Unsecured debentures	March	4.16	2052	**100**	(1)
Newfoundland Power					
First mortgage sinking fund bonds	April	4.20	2052	**75**	(1) (4) (6)
Caribbean Utilities					
Unsecured senior notes	November	5.88	2052	**US 80**	(1) (3)
Fortis					
Unsecured senior notes	May	4.43 (7)	2029	**500**	(4) (8)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund or refinance, in part or in full, a portfolio of new and/or existing eligible green projects*
(3) *Fund capital expenditures*
(4) *General corporate purposes*
(5) *ITC entered into interest rate swaps which reduced the effective interest rate to 3.54%. See Note 25 to the 2022 Annual Financial Statements*
(6) *Repay maturing long-term debt*
(7) *The Corporation entered into cross-currency interest rate swaps to effectively convert the debt into US$391 million with an interest rate of 4.34% (Note 25)*
(8) *Fund the June 2022 redemption of the Corporation's $500 million, 2.85% senior unsecured notes due December 2023*

Long-Term Debt Repayments

The consolidated requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

($ millions)	**Total**
2023	2,481
2024	1,434
2025	518
2026	2,434
2027	1,977
Thereafter	19,734
	28,578

14. LONG-TERM DEBT (cont'd)

In November 2022, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. As at December 31, 2022, $2.0 billion remained available under the short-form base shelf prospectus.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**2022**	2021
Total credit facilities	3,795	2,055	**5,850**	4,846
Credit facilities utilized:				
Short-term borrowings [1]	(253)	—	**(253)**	(247)
Long-term debt (including current portion) [2]	(922)	(735)	**(1,657)**	(1,305)
Letters of credit outstanding	(76)	(52)	**(128)**	(115)
Credit facilities unutilized	2,544	1,268	**3,812**	3,179

[1] *The weighted average interest rate was approximately 4.9% (2021 - 0.6%).*

[2] *The weighted average interest rate was approximately 5.1% (2021 - 0.9%). The current portion was $1,376 million (2021 - $888 million).*

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.6 billion of the total credit facilities are committed facilities with maturities ranging from 2023 through 2027.

In 2022, Central Hudson increased its available credit facilities from US$230 million to US$320 million.

In May 2022, the Corporation amended its unsecured $1.3 billion revolving term committed credit facility agreement to extend the maturity to July 2027, and to establish a sustainability-linked loan structure based on the Corporation's achievement of targets for diversity on the Board of Directors and Scope 1 greenhouse gas emissions for 2022 through 2025. Maximum potential annual margin pricing adjustments are +/- 5 basis points and +/- 1 basis point for drawn and undrawn funds, respectively.

Also in May 2022, the Corporation entered into an unsecured US$500 million non-revolving term credit facility. The facility has an initial one-year term and is repayable at any time without penalty.

Consolidated credit facilities of approximately $5.9 billion as at December 31, 2022 are itemized below.

($ millions)		**Amount**	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [1]	**US**	**900**	2024
UNS Energy	**US**	**375**	2026
Central Hudson	**US**	**250**	2025
FortisBC Energy		**700**	2027
FortisAlberta		**250**	2027
FortisBC Electric		**150**	2027
Other Electric		**255**	[2]
Other Electric	**US**	**83**	2025
Corporate and Other		**1,350**	[3]
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**70**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2024
FortisBC Electric - unsecured demand overdraft facility		**10**	n/a
Other Electric - unsecured demand facilities		**20**	n/a
Other Electric - unsecured demand facility and emergency standby loan	**US**	**60**	2023
Corporate and Other			
Unsecured non-revolving facility	**US**	**500**	2023
Unsecured non-revolving facility		**27**	n/a

[1] *ITC also has a US$400 million commercial paper program, under which US$134 million was outstanding as at December 31, 2022 (2021 - US$155 million), as reported in short-term borrowings.*

[2] *$65 million in 2025, $90 million in 2025 and $100 million in 2027*

[3] *$50 million in 2024 and $1.3 billion in 2027*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 25 years, with optional renewal terms. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the leased premises.

The Corporation's subsidiaries also have finance leases related to generating facilities with remaining terms of up to 33 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2022**	2021
Operating leases		
Other assets	**43**	40
Accounts payable and other current liabilities	**(9)**	(8)
Other liabilities	**(34)**	(32)
Finance leases [1]		
Regulatory assets	**132**	127
PPE, net	**206**	210
Accounts payable and other current liabilities	**(2)**	(4)
Finance leases	**(336)**	(333)

[1] *FortisBC Electric has a finance lease for the BPPA (Note 8), which relates to the sale of the output of the Brilliant hydroelectric plant, and for the Brilliant Terminal Station ("BTS"), which relates to the use of the station. Both agreements expire in 2056. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which includes the original and ongoing capital cost, and related variable power purchase costs. The BTS requires semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs.*

The components of lease expense were as follows.

($ millions)	**2022**	2021
Operating lease cost	**9**	8
Finance lease cost:		
Amortization	**1**	2
Interest	**33**	32
Variable lease cost	**21**	19
Total lease cost	**64**	61

As at December 31, 2022, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2023	10	35	**45**
2024	9	35	**44**
2025	6	35	**41**
2026	5	35	**40**
2027	3	36	**39**
Thereafter	19	1,001	**1,020**
	52	1,177	**1,229**
Less: Imputed interest	(9)	(839)	**(848)**
Total lease obligations	43	338	**381**
Less: Current installments	(9)	(2)	**(11)**
	34	336	**370**

15. LEASES (cont'd)

Supplemental lease information follows.

($ millions, except as indicated)	**2022**	2021
Weighted average remaining lease term *(years)*		
Operating leases	**9**	10
Finance leases	**33**	34
Weighted average discount rate *(%)*		
Operating leases	**4.1**	3.8
Finance leases	**5.0**	5.1
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**(8)**	(8)
Financing cash flows used for finance leases	**(1)**	(2)

16. OTHER LIABILITIES

($ millions)	**2022**	2021
Employee future benefits (Note 23)	**423**	740
AROs (Note 3)	**174**	184
Customer and other deposits	**107**	99
Manufactured gas plant site remediation (1)	**95**	83
Stock-based compensation plans (Note 20)	**79**	96
Derivatives (Note 25)	**72**	7
Deferred compensation plan (Note 9)	**48**	50
Mine reclamation obligations (2)	**39**	44
Operating leases (Note 15)	**34**	32
Retail energy contract (3)	**33**	40
Other	**42**	34
	1,146	1,409

(1) Environmental regulations require Central Hudson to investigate sites at which it or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. As at December 31, 2022, an obligation of $100 million was recognized, including a current portion of $5 million recognized in accounts payable and other current liabilities (Note 13). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 8).

(2) TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $54 million. The present value of the estimated future liability is shown in the table above.

(3) In 2020, FortisAlberta entered into an eight-year agreement with an existing retail energy provider to continue to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment which is being amortized to revenue over the life of the agreement.

17. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for stock options.

	2022			2021		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,330**	**478.6**	**2.78**	1,231	470.9	2.61
Potential dilutive effect of stock options	**—**	**0.4**	**—**	—	0.5	—
Diluted EPS	**1,330**	**479.0**	**2.78**	1,231	471.4	2.61

18. PREFERENCE SHARES

Authorized

An unlimited number of first preference shares and second preference shares, without nominal or par value.

Issued and Outstanding First Preference Shares	**2022**		2021	
	Number of Shares *(thousands)*	**Amount** *($ millions)*	Number of Shares *(thousands)*	Amount *($ millions)*
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,665	188
Series I	**2,335**	**57**	2,335	57
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**1,623**	66,200	1,623

Characteristics of the first preference shares are as follows.

First Preference Shares (1) (2)	**Initial Yield** *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One-For-One Basis**
Perpetual fixed rate						
Series F	4.90	1.2250	—	Currently Redeemable	25.00	—
Series J	4.75	1.1875	—	Currently Redeemable	25.00	—
Fixed rate reset (3) (4)						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating rate reset (4) (5)						
Series I	2.10	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	Series M

(1) *Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.*

(2) *On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.*

(3) *On the redemption and/or conversion option date, and on each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.*

(4) *On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Redeemable first preference shares of a specified series.*

(5) *The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.*

18. PREFERENCE SHARES *(cont'd)*

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of first and second preference shares, and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution, in priority to or ratably with the holders of the common shares.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	**Opening Balance**	**Net Change**	**Ending Balance**
2022			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**273**	**1,222**	**1,495**
Hedges of net investments in foreign operations	**(276)**	**(254)**	**(530)**
Income tax (expense) recovery	**(8)**	**15**	**7**
	(11)	**983**	**972**
Other			
Interest rate hedges (Note 25)	**(5)**	**54**	**49**
Unrealized employee future benefits (losses) gains (Note 23)	**(36)**	**30**	**(6)**
Income tax recovery (expense)	**12**	**(19)**	**(7)**
	(29)	**65**	**36**
Accumulated other comprehensive income	**(40)**	**1,048**	**1,008**
2021			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	377	(104)	273
Hedges of net investments in foreign operations	(299)	23	(276)
Income tax expense	(6)	(2)	(8)
	72	(83)	(11)
Other			
Interest rate hedges (Note 25)	(4)	(1)	(5)
Unrealized employee future benefits (losses) gains (Note 23)	(49)	13	(36)
Income tax recovery (expense)	15	(3)	12
	(38)	9	(29)
Accumulated other comprehensive income	34	(74)	(40)

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Effective 2022, the Corporation no longer grants stock options. Existing options to purchase common shares of the Corporation are exercisable for a period of 10 years from the grant date, expire no later than three years after the death or retirement of the optionee, and vest evenly over a four-year period on each anniversary of the grant date.

As at December 31, 2022, the Corporation had 2.3 million (2021 - 2.9 million) stock options outstanding with a weighted average exercise price of $47.72 (2021 - $47.20). The options vested as of December 31, 2022, were 1.5 million (2021 – 1.4 million) with a weighted average exercise price of $44.86 (2021 - $42.76).

In 2022, 1 million stock options were exercised (2021 - 1 million) for cash proceeds of $26 million (2021 - $32 million) and an intrinsic value realized by employees of $9 million (2021 - $11 million).

20. STOCK-BASED COMPENSATION PLANS (cont'd)

DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to DSUs.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**183**	147
Granted	**33**	30
Notional dividends reinvested	**8**	6
End of year	**224**	183

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2022 or 2021.

PSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three-year period, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the vesting date; and (iii) a payout percentage that may range from 0% to 200%.

The payout percentage is based on the Corporation's performance over the three-year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; and (ii) the Corporation's cumulative EPS, or for subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant. Beginning with the 2022 PSU grant, the Corporation's Scope 1 carbon reduction performance as compared to the target established at the time of the grant has been included in the payout percentage.

The following table summarizes information related to PSUs.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**1,898**	1,976
Granted	**580**	587
Notional dividends reinvested	**58**	60
Paid out	**(712)**	(697)
Cancelled/forfeited	**(34)**	(28)
End of year	**1,790**	1,898
Additional information *($ millions)*		
Compensation expense recognized	**25**	74
Compensation expense unrecognized (1)	**24**	33
Cash payout	**66**	50
Accrued liability as at December 31 (2)	**90**	132
Aggregate intrinsic value as at December 31 (3)	**114**	165

(1) *Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years*

(2) *Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in other liabilities (Notes 13 and 16)*

(3) *Relates to outstanding PSUs and reflects a weighted average contractual life of one year*

20. STOCK-BASED COMPENSATION PLANS (cont'd)

RSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash or, beginning with the 2020 grant, common shares of the Corporation. Effective January 1, 2020, new RSU issuances may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executives' settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**1,060**	1,048
Granted	**331**	378
Notional dividends reinvested	**29**	32
Paid out	**(410)**	(371)
Cancelled/forfeited	**(33)**	(27)
End of year	**977**	1,060
Additional information *($ millions)*		
Compensation expense recognized	**16**	26
Compensation expense unrecognized (1)	**16**	17
Cash payout	**25**	21
Accrued liability as at December 31 (2)	**40**	46
Aggregate intrinsic value as at December 31 (3)	**56**	63

(1) *Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years*

(2) *Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)*

(3) *Relates to outstanding RSUs and reflects a weighted average contractual life of one year*

21. OTHER INCOME, NET

($ millions)	**2022**	2021
Non-service component of net periodic benefit cost	**92**	45
Equity component of AFUDC	**78**	77
Interest income	**11**	5
(Loss) gain on derivatives, net	**(17)**	30
(Loss) gain on retirement investments, net	**(18)**	4
Other	**19**	12
	165	173

22. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consisted of the following.

($ millions)	**2022**	2021
Gross deferred income tax assets		
Regulatory liabilities	**674**	560
Tax loss and credit carryforwards	**658**	556
Employee future benefits	**161**	169
Other	**160**	91
	1,653	1,376
Valuation allowance	**(32)**	(23)
Net deferred income tax asset	**1,621**	1,353
Gross deferred income tax liabilities		
PPE	**(5,146)**	(4,571)
Regulatory assets	**(388)**	(283)
Intangible assets	**(147)**	(126)
	(5,681)	(4,980)
Net deferred income tax liability	**(4,060)**	(3,627)

Income Tax Expense

($ millions)	**2022**	2021
Canadian		
Earnings before income tax expense	**447**	427
Current income tax	**93**	84
Deferred income tax	**(41)**	(35)
Total Canadian	**52**	49
Foreign		
Earnings before income tax expense	**1,356**	1,212
Current income tax	**14**	3
Deferred income tax	**223**	182
Total Foreign	**237**	185
Income tax expense	**289**	234

Income tax expense differs from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income tax expense.

22. INCOME TAXES (cont'd)

The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

($ millions, except as indicated)	**2022**	2021
Earnings before income tax expense	**1,803**	1,639
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**541**	492
Decrease resulting from:		
Foreign and other statutory rate differentials	**(162)**	(155)
AFUDC	**(18)**	(16)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(74)**	(74)
Items capitalized for accounting purposes but expensed for income tax purposes	**(7)**	(8)
Other	**9**	(5)
Income tax expense	**289**	234
Effective tax rate *(%)*	**16.0**	14.3

Income Tax Carryforwards

($ millions)	Expiring Year	**2022**
Canadian		
Non-capital loss	2028-2042	**393**
Foreign		
Federal and state net operating loss[1]	2023-2042	**3,093**
Other tax credits	2023-2042	**131**
		3,224
Total income tax carryforwards recognized		**3,617**

[1] *Indefinite carryforward for Federal net operating losses, and for states that have adopted the Federal provisions, effective for tax years beginning after December 31, 2017*

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2018 to 2022 taxation years are still open for audit in Canadian jurisdictions, and its 2018 to 2022 taxation years are still open for audit in United States jurisdictions.

23. EMPLOYEE FUTURE BENEFITS

For defined benefit pension and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2019 for FortisBC Electric plans (non-unionized employees), Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2020 for the Corporation; December 31, 2021 for FortisBC Energy and the remaining FortisBC Electric plans and December 31, 2022 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans. The investment objective is to maximize returns in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and recognized expense.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets

(weighted average %)	**2022 Target Allocation**	**2022**	2021
Equities	**47**	**48**	48
Fixed income	**46**	**43**	45
Real estate	**6**	**8**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
2022				
Equities	**666**	**1,005**	**—**	**1,671**
Fixed income	**199**	**1,289**	**—**	**1,488**
Real estate	**—**	**—**	**264**	**264**
Private equities	**—**	**—**	**18**	**18**
Cash and other	**5**	**22**	**—**	**27**
	870	**2,316**	**282**	**3,468**
2021				
Equities	749	1,271	—	2,020
Fixed income	219	1,642	—	1,861
Real estate	—	—	235	235
Private equities	—	—	21	21
Cash and other	10	15	—	25
	978	2,928	256	4,162

(1) *See Note 25 for a description of the fair value hierarchy.*

The following table reconciles the changes in the fair value of plan assets that have been measured using Level 3 inputs.

($ millions)	**2022**	2021
Balance, beginning of year	**256**	224
Return on plan assets	**28**	32
Foreign currency translation	**3**	—
Purchases, sales and settlements	**(5)**	—
Balance, end of year	**282**	256

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Change in benefit obligation [1]				
Balance, beginning of year	**3,922**	3,995	**747**	789
Service costs	**106**	109	**35**	35
Employee contributions	**18**	18	**3**	2
Interest costs	**114**	98	**21**	19
Benefits paid	**(195)**	(170)	**(29)**	(25)
Actuarial gains	**(1,026)**	(111)	**(225)**	(70)
Past service costs (credits)/plan amendments	**—**	(2)	**1**	—
Foreign currency translation	**124**	(15)	**29**	(3)
Balance, end of year [2]	**3,063**	3,922	**582**	747
Change in value of plan assets				
Balance, beginning of year	**3,722**	3,528	**440**	391
Actual return on plan assets	**(651)**	291	**(77)**	48
Benefits paid	**(187)**	(158)	**(24)**	(21)
Employee contributions	**18**	18	**3**	2
Employer contributions	**54**	55	**19**	22
Foreign currency translation	**123**	(12)	**28**	(2)
Balance, end of year	**3,079**	3,722	**389**	440
Funded status	**16**	(200)	**(193)**	(307)
Balance sheet presentation				
Other assets (Note 9)	**188**	204	**86**	55
Other current liabilities (Note 13)	**(15)**	(13)	**(13)**	(13)
Other liabilities (Note 16)	**(157)**	(391)	**(266)**	(349)
	16	(200)	**(193)**	(307)

[1] *Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.*

[2] *The accumulated benefit obligation, which excludes assumptions about future salary levels, for defined benefit pension plans was $2,818 million as at December 31, 2022 (2021 - $3,586 million).*

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2022, the obligation was $978 million compared to plan assets of $790 million (2021 - $2,188 million and $1,799 million, respectively).

For those defined benefit pension plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2022, the obligation was $833 million compared to plan assets of $790 million (2021 - $1,243 million and $1,063 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2022, the obligation was $310 million compared to plan assets of $31 million (2021 - $398 million and $36 million, respectively).

Net Benefit Cost [1]

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Service costs	**106**	109	**35**	35
Interest costs	**114**	98	**21**	19
Expected return on plan assets	**(194)**	(177)	**(23)**	(19)
Amortization of actuarial losses (gains)	**4**	36	**(10)**	(2)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(1)
Regulatory adjustments	**(10)**	(1)	**4**	3
	19	64	**26**	35

[1] *The non-service benefit cost components of net periodic benefit cost are included in other income, net in the consolidated statements of earnings.*

23. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Unamortized net actuarial losses (gains)	**9**	33	**(11)**	(5)
Unamortized past service costs	**1**	1	**7**	7
Income tax (recovery) expense	**(2)**	(8)	**1**	—
Accumulated other comprehensive income	**8**	26	**(3)**	2
Net actuarial losses (gains)	**103**	260	**(195)**	(81)
Past service credits	**(4)**	(5)	**(4)**	(6)
Other regulatory deferrals	**(6)**	10	**7**	14
	93	265	**(192)**	(73)
Regulatory assets (Note 8)	**207**	376	**—**	12
Regulatory liabilities (Note 8)	**(114)**	(111)	**(192)**	(85)
Net regulatory assets (liabilities)	**93**	265	**(192)**	(73)

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory liabilities.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Current year net actuarial gains	**(23)**	(10)	**(6)**	(4)
Amortization of actuarial losses	**1**	1	**—**	—
Foreign currency translation	**(2)**	—	**—**	—
Income tax expense	**6**	2	**1**	1
Total recognized in comprehensive income	**(18)**	(7)	**(5)**	(3)
Current year net actuarial gains	**(155)**	(220)	**(118)**	(95)
Past service cost/plan amendments	**—**	—	**1**	—
Amortization of actuarial (losses) gains	**(6)**	(35)	**10**	2
Amortization of past service credits	**1**	2	**1**	2
Foreign currency translation	**4**	(2)	**(6)**	—
Regulatory adjustments	**(16)**	(3)	**(7)**	(4)
Total recognized in regulatory liabilities	**(172)**	(258)	**(119)**	(95)

Significant Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2022**	2021	**2022**	2021
Discount rate during the year (1)	**2.97**	2.60	**2.97**	2.60
Discount rate as at December 31	**5.27**	3.00	**5.36**	2.97
Expected long-term rate of return on plan assets (2)	**5.87**	5.40	**5.00**	4.88
Rate of compensation increase	**3.33**	3.30	**—**	—
Health care cost trend increase as at December 31 (3)	**—**	—	**4.48**	4.49

(1) *ITC and UNS Energy use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.*

(2) *Developed by management using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

(3) *The projected 2023 weighted average health care cost trend rate is 6.17% and is assumed to decrease over the next 12 years to the weighted average ultimate health care cost trend rate of 4.48% in 2034 and thereafter.*

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments *($ millions)*	**Defined Benefit Pension Payments**	**OPEB Payments**
2023	$ 177	$ 30
2024	183	32
2025	190	33
2026	197	35
2027	203	35
2028-2032	1,094	191

During 2023, the Corporation expects to contribute $35 million for defined benefit pension plans and $20 million for OPEB plans.

In 2022, the Corporation expensed $47 million (2021 - $44 million) related to defined contribution pension plans.

24. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	**2022**	2021
Cash paid (received) for		
Interest	**1,057**	986
Income taxes	**79**	(13)
Change in working capital		
Accounts receivable and other current assets	**(479)**	(88)
Prepaid expenses	**(22)**	(15)
Inventories	**(153)**	(56)
Regulatory assets - current portion	**(307)**	(99)
Accounts payable and other current liabilities	**449**	164
Regulatory liabilities - current portion	**33**	(50)
	(479)	(144)
Non-cash investing and financing activities		
Accrued capital expenditures	**411**	432
Common share dividends reinvested	**364**	356
Contributions in aid of construction	**13**	13

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flow.

Cash flow associated with the settlement of all derivatives is included in operating activities on the consolidated statements of cash flows.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2022, unrealized losses of $84 million (2021 - $20 million) were recognized as regulatory assets and unrealized gains of $224 million (2021 - $52 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2022, unrealized gains of $34 million (2021 - $21 million) were recognized in revenue.

Total Return Swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $114 million and terms of one to three years expiring at varying dates through January 2025. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2022, unrealized losses of $22 million (2021 - unrealized gains of $17 million) were recognized in other income, net.

Foreign Exchange Contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through May 2024 and have a combined notional amount of $352 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2022, unrealized losses of $9 million (2021 - $11 million) were recognized in other income, net.

Interest Rate Swaps

ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of US$450 million, were terminated in September 2022 with the issuance of US$600 million senior notes and realized gains of $52 million (US$39 million) were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

Cross-Currency Interest Rate Swaps

In May 2022, the Corporation entered into cross-currency interest rate swaps with a 7-year term to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt (Note 14). The Corporation designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on secured overnight financing rates. In 2022, unrealized losses of $17 million were recorded in other comprehensive income.

Other Investments

UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. These investments are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2022, unrealized losses of $11 million (2021 - unrealized gains of $5 million) were recognized in other income, net.

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Recurring Fair Value Measures

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1** (1)	**Level 2** (1)	**Level 3** (1)	**Total**
As at December 31, 2022				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	**—**	**304**	**—**	**304**
Energy contracts not subject to regulatory deferral (2)	**—**	**49**	**—**	**49**
Other investments (4)	**150**	**—**	**—**	**150**
	150	**353**	**—**	**503**
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	**—**	**(164)**	**—**	**(164)**
Energy contracts not subject to regulatory deferral (5)	**—**	**(8)**	**—**	**(8)**
Foreign exchange contracts, total return and cross-currency interest rate swaps (5)	**—**	**(26)**	**—**	**(26)**
	—	**(198)**	**—**	**(198)**
As at December 31, 2021				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	—	78	—	78
Energy contracts not subject to regulatory deferral (2)	—	16	—	16
Foreign exchange contracts, total return and interest rate swaps (2)	23	2	—	25
Other investments (4)	137	—	—	137
	160	96	—	256
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	—	(46)	—	(46)
Energy contracts not subject to regulatory deferral (5)	—	(3)	—	(3)
	—	(49)	—	(49)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1 - unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*

(2) *Included in accounts receivable and other current assets or other assets*

(3) *Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.*

(4) *Included in cash and cash equivalents and other assets*

(5) *Included in accounts payable and other current liabilities or other liabilities*

Energy Contracts

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

($ millions)	**Gross Amount Recognized In Balance Sheet**	**Counterparty Netting of Energy Contracts**	**Cash Collateral Received/Posted**	**Net Amount**
As at December 31, 2022				
Derivative assets	**353**	**54**	**63**	**236**
Derivative liabilities	**(172)**	**(54)**	**—**	**(118)**
As at December 31, 2021				
Derivative assets	94	25	7	62
Derivative liabilities	(49)	(25)	—	(24)

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Volume of Derivative Activity

As at December 31, 2022, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

	2022	2021
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**586**	509
Electricity power purchase contracts *(GWh)*	**224**	731
Gas swap contracts *(PJ)*	**185**	151
Gas supply contract premiums *(PJ)*	**148**	144
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,886**	1,886
Gas swap contracts *(PJ)*	**34**	29

[(1)] *GWh means gigawatt hours and PJ means petajoules*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. The customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable due to the suspension of collection efforts in response to the COVID-19 pandemic, as well as higher commodity prices. Central Hudson continues to proactively contact customers regarding past-due balances to advise them of financial assistance available through federal and state programs, and collection efforts are expected to expand in 2023. Under its regulatory framework, Central Hudson can defer uncollectible write-offs that exceed 10 basis points above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy, Central Hudson and FortisBC Energy, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $178 million as at December 31, 2022 (2021 - $59 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize Limited and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has limited this exposure through hedging.

As at December 31, 2022, US$2.9 billion (2021 - US$2.2 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.6 billion (2021 - US$10.8 billion) unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's remaining financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2022, the carrying value of long-term debt, including current portion, was $28.6 billion (2021 - $25.5 billion) compared to an estimated fair value of $25.8 billion (2021 - $28.8 billion).

26. COMMITMENTS AND CONTINGENCIES

As at December 31, 2022, unconditional minimum purchase obligations were as follows.

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Gas and fuel purchase obligations [(1)]	**5,720**	1,024	516	461	374	328	3,017
Waneta Expansion capacity agreement [(2)]	**2,472**	54	55	56	58	59	2,190
Renewable PPAs [(3)]	**1,926**	131	131	131	131	130	1,272
Power purchase obligations [(4)]	**1,691**	334	253	191	192	113	608
ITC easement agreement [(5)]	**380**	14	14	14	14	14	310
Debt collection agreement [(6)]	**106**	3	3	3	3	3	91
Renewable energy credit purchase agreements [(7)]	**77**	18	14	7	7	6	25
Other [(8)]	**132**	21	9	20	3	3	76
	12,504	**1,599**	**995**	**883**	**782**	**656**	**7,589**

[(1)] *FortisBC Energy ($4,804 million):* includes contracts of $2,720 million for the purchase of renewable natural gas expiring in 2044 and contracts of $2,084 million for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2022. The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

UNS Energy ($801 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2022. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates through 2040.

[(2)] *FortisBC Electric* is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

[(3)] *TEP and UNS Electric* are party to renewable PPAs, with expiry dates from 2027 through 2051, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. Amounts are the estimated future payments.

[(4)] *Maritime Electric ($746 million):* includes an energy purchase agreement and transmission capacity contract for 30 MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario ($489 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually through December 2030.

FortisBC Electric ($258 million): includes an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

UNS Energy ($153 million): an agreement with Salt River Project Agricultural Improvement and Power District to purchase up to 300 MW of capacity, power and ancillary services through 2023. TEP will pay monthly capacity charges and variable power charges.

[(5)] ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

[(6)] Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, are collected in customer rates.

[(7)] UNS Energy and Central Hudson are party to REC purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

[(8)] Includes AROs and joint-use asset and shared service agreements.

26. COMMITMENTS AND CONTINGENCIES (cont'd)

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. The Wataynikaneyap Partnership has loan agreements in place to finance the project during construction. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $339 million for Four Corners. As at December 31, 2022, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $74 million, for which it has issued a parental guarantee. As at December 31, 2022, there was no obligation under this guarantee.

As at December 31, 2022, FortisBC Holdings Inc. ("FHI") had $142 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013, FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right-of-way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In 2016, the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In 2017, the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

Exhibit B, Tab 1, Schedule 1

Transmission System Project Plan

TRANSMISSION SYSTEM PROJECT PLAN

A. Introduction

WPLP's Transmission Project is a major capital investment that includes the initial development, construction and in-servicing of its entire Transmission System. WPLP has carried out a comprehensive Transmission Project planning and development process, engaged and continues to engage extensively with potentially impacted Indigenous and Métis communities, land users and other relevant stakeholders, undertaken commercially prudent processes for construction contracting and contract management, secured necessary financing, and implemented appropriate organizational structures and processes to monitor and oversee execution of the Transmission Project.

The present Application seeks approval of WPLP's transmission revenue requirement on a cost of service basis for a single test year (2024), with capital expenditure forecasts covering the 2023-2024 period during which the Transmission System will continue to be constructed and placed into service (in stages). The proposed revenue requirement is therefore largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that were put into service in 2022 and are expected to go in-service in 2023, as well as the additional elements that are expected to go into service during 2024. Furthermore, the proposed revenue requirement includes operating expenses, including in relation to the assets that are in service or are expected to be going into service in 2023 and 2024.

In granting leave to construct in EB-2018-0190, the OEB approved construction of the Transmission Project and found that its impacts with respect to price, reliability and quality of service are reasonable. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a Transmission System Plan ("TSP") or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses this Exhibit 'B' to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from the construction phase to ongoing operation of the Transmission System. WPLP has updated this Exhibit 'B' since its last transmission rate application (EB-2022-0149) and intends to further update it in its next single-year revenue requirement application. WPLP anticipates that it will file an initial TSP in conjunction with its first multi-year revenue requirement application following completion of the Transmission Project.

The majority of WPLP's forecasted investments during the 2024 test year are related to the initial construction of the Transmission System and General Plant investments for facilities, equipment and systems that are required to enable and support the ongoing operation of the Transmission System. Due to WPLP's focus on monitoring and overseeing the construction of the Transmission System and supporting facilities, connecting HORCI's distribution systems in each of the 16 connecting Indigenous communities[1] and ramping up operation of the Transmission System assets, WPLP does not anticipate having significant capital investment needs, incremental to its initial construction costs, during the 2024 test year.[2] System Renewal and System Service needs are expected to be *de minimus* due to the Transmission System being newly built and designed to meet anticipated operational needs and customer service requirements.

The General Plant investments referred to above include fleet, facilities and business systems. Most of these investments are planned for post-2024, with in-service dates that coincide with WPLP's transition from construction oversight and project management to system operation as more assets are placed in service, as discussed in Exhibit B-1-4.

Regarding the in-service schedule for the Transmission Project, on August 12, 2022, WPLP placed into service the Line to Pickle Lake, including its 2 associated substations. In September 2022, WPLP placed into service the Red Lake Substation, and in October and November 2022, WPLP placed into service the segments of the Remote Connection Lines necessary for connection of

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[1] While a 17th community, McDowell Lake First Nation, is not forecasted to be connected during this initial construction period, WPLP's Transmission System is designed to permit the future connection of this community.

[2] As noted in Exhibit H-2-2, WPLP anticipates that it may incur incremental costs arising from COVID-19 impacts and related matters in relation to the initial construction of the Transmission Project, but those amounts are the subject of ongoing commercial discussions with its EPC contractor.

North Caribou Lake First Nation and Kingfisher Lake First Nation, respectively, including 3 associated substations. In 2023, WPLP has converted the Pikangikum Distribution System to form part of the Transmission System as of May 12, 2023. Also in 2023, WPLP plans to put into service portions of the Remote Connection Lines, including associated stations, that are needed to connect six additional communities.[3] WPLP completed and energized the transmission system (line and Substation) required to energize Wunnumin Lake First Nation on May 25, 2023. Together, these in-service assets include 14 line segments and 8 substations[4], and reflect approximately 25.4% of the total forecast Transmission Project cost. In 2024, WPLP plans to put into service the portions of the Remote Connection Lines and associated stations needed to connect the remaining seven communities[5], which consists of 15 line segments and 9 substations, and which reflect approximately 33.7% of the total forecast Transmission Project cost.

Following completion of the Transmission Project in 2024, WPLP anticipates receiving a significant capital contribution from the Federal Government, as discussed in Exhibit I-4-1. WPLP also expects to transition from project financing to long-term debt financing in late 2024 or early 2025. Accordingly, WPLP anticipates filing its first multi-year incentive-based rate application in 2025 (for a 2026 Test Year), once the amount of the federal capital contribution and interest rate(s) applicable to WPLP's long-term debt are more certain.

B. Roadmap

WPLP's Transmission System Project Plan, which comprises Exhibit 'B', is organized as follows:

- The balance of this Exhibit B-1-1 describes the scope of the Transmission Project, including the physical components of the Transmission System as approved in the Leave

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[3] Wunnumin Lake First Nation (May 2023), Muskrat Dam First Nation (July 2023), Wawakapewin First Nation (July 2023), Bearskin Lake First Nation (July 2023), Kasabonika Lake First Nation (August 2023) and Sachigo Lake First Nation (November 2023).

[4] These counts include line segments and substations associated with the Pikangikum Distribution System that are already in service and transitioned to a transmission supply on May 12, 2023.

[5] Poplar Hill First Nation (April 2024), Kitchnuhmaykoosib Inninuwug (April 2024), Wapekeka First Nation (April 2024), Deer Lake First Nation (May 2024), Sandy Lake First Nation (June 2024), North Spirit Lake First Nation (July 2024), Keewaywin First Nation (August 2024).

to Construct Proceeding, as well as changes made subsequent to that proceeding and further changes that are being contemplated.

- Exhibit B-1-2 describes the key elements of WPLP's project planning and development process and provides an overview of the key development activities that have been carried out by WPLP, both following the granting of Leave to Construct and since the 2023 revenue requirement application.

- Exhibit B-1-3 describes the current construction schedule, including the sequencing of in-service dates for project components and segments. In addition, WPLP identifies and explains any changes in the construction schedule relative to that which was presented in the 2023 revenue requirement proceeding, and associated schedule risks and mitigation.

- Exhibit B-1-4 sets out WPLP's approach to organizing and executing the Transmission Project, including its structure during the construction period, the manner in which it is coordinating and providing oversight of key contractors, change management processes, cost and performance management, project tracking and reporting, as well as the company's efforts and plans for evolving its organization to support operations as additional segments come into service and to ensure it is prepared for ongoing utility operations following project completion.

- Exhibit B-1-5 provides detailed Transmission Project cost information, as well as information on other infrastructure capital costs and operating costs, and explanations for variances between estimated project costs presented in the 2023 revenue requirement application and current forecasts. In addition, this schedule describes how overhead costs are assigned to or allocated between capital and OM&A for each of the Line to Pickle Lake and Remote Connection Line portions of the Transmission System over the construction period.

C. Transmission Project Scope

1. Transmission System Components

Upon completion of construction, WPLP's Transmission System will operate as a single transmission system in northwestern Ontario, one part of which will reinforce transmission to Pickle Lake (the "Line to Pickle Lake") and the balance of which will connect to the provincial power system 16 remote Indigenous communities that are currently served by diesel generation (the "Remote Connection Lines").[6] These two components of WPLP's Transmission System are depicted in the Transmission System Map provided in **Appendix 'A'** and are described as follows.

(a) Line to Pickle Lake

The Line to Pickle Lake is an approximately 303 km transmission line from a point between Dryden and Ignace to Pickle Lake, including associated stations and ancillary facilities. The Line to Pickle Lake reinforces the transmission supply to Pickle Lake and includes the following elements:

- a 230 kV switching station located adjacent to the existing Hydro One circuit D26A approximately 8 km southeast of Dinorwic ("Wataynikaneyap SS");
- an approximately 303 km single circuit, overhead, 230 kV transmission line running from the Wataynikaneyap SS generally in a northeasterly direction to the Wataynikaneyap TS (described below); and
- a 230/115 kV transformer station located near the intersection of Hwy 599 and Cohen Avenue in Central Patricia, which is approximately 3 km northeast from the Town of Pickle Lake ("Wataynikaneyap TS").

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[6] One of the 16 communities, Pikangikum First Nation became grid-connected in 2018 through an interim 44 kV connection. On May 12, 2023, the Pikangikum Distribution System was converted to 115 kV supply and now forms part of WPLP's Transmission System. The future connection of a 17th community, McDowell Lake First Nation, would also be supported through the Remote Connection Lines.

In addition, immediately next to WPLP's Wataynikaneyap SS there is a small, separate fenced area called Dinorwic Junction ("Dinorwic JCT") which supports the connection of WPLP's 230 kV tap from Wataynikaneyap SS to Hydro One's 230 kV transmission line D26A. Dinorwic JCT is owned and operated by Hydro One and houses two new 230 kV motor-operated switches on transmission line D26A on either side of WPLP's 230 kV tap. Similarly, immediately next to WPLP's Wataynikaneyap TS is a separately fenced 115 kV switching station called Pickle Lake SS, which supports the connection of WPLP's Wataynikaneyap TS to Hydro One's 115 kV transmission line E1C. Pickle Lake SS is owned and operated by Hydro One and houses two 115 kV circuit breakers, as well as associated switches and protection and control facilities. Hydro One's customers at Crow River DS and Musselwhite CSS, near the end of transmission line E1C, remain connected to Hydro One's transmission system via Pickle Lake SS, but benefit from the increased available capacity and the improved system reliability provided by WPLP's Line to Pickle Lake.

(b) Remote Connection Lines

The connection of remote Indigenous communities will be achieved by means of approximately 903 km of new 115 kV, 44 kV and 25 kV transmission lines north of Pickle Lake (the "Pickle Lake Remote Connection Lines"), and approximately 535 km[7] of new 115 kV and 25 kV transmission lines north of Red Lake (the "Red Lake Remote Connection Lines"), including associated stations and ancillary facilities (together, the "Remote Connection Lines"). By the time the construction period concludes in 2024, a total of 16 remote Indigenous communities, all of which are Participating First Nations, will connect to the Transmission System, and thereby to the provincial electricity system.[8] In EB-2018-0190, the OEB approved WPLP's request under subsection 84(b) of the OEB Act for the 44 kV and 25 kV segments of the Remote Connection Lines to be deemed

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[7] The total length indicated here has been adjusted by 3 km as compared to the previous application in EB-2022-0149. The revised total length reflects the as-built and/or ground surveyed values and subtraction of the lengths related to assets that will be transferred to HORCI (approximately 50-300 meters for each 25 kV segment).

[8] The Transmission System is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

to be transmission facilities that are part of WPLP's Transmission System notwithstanding that these segments will have voltages less than 50 kV.[9]

The Pickle Lake Remote Connection Lines include the following elements:

- approximately 903 km of single circuit, overhead, 115 kV, 44 kV and 25 kV transmission lines running from the Wataynikaneyap TS generally in a northerly direction to one switching station and subsequently to a series of nine transformer stations from which transmission service will be provided by WPLP to Hydro One Remote Communities Inc., and from which Hydro One Remote Communities Inc. will provide distribution service to customers in ten remote Indigenous communities.[10]

The Red Lake Remote Connection Lines include the following elements:

- a 115 kV switching station located approximately 4 km southeast of Hydro One's Red Lake TS adjacent to Hydro One's existing circuit E2R (the "Red Lake SS"); and
- approximately 535 km of single circuit, overhead, 115 kV and 25 kV transmission lines running from the Red Lake SS generally in a northerly direction to a series of three switching stations and six transformer stations from which transmission service will be provided by WPLP to Hydro One Remote Communities Inc., and from which Hydro One Remote Communities Inc. will provide distribution service to customers in six remote Indigenous communities.[11,12]

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[9] OEB, Decision and Order in EB-2018-0190, April 1, 2019, p. 30.

[10] (1) Wunnumin Lake First Nation, (2) Kingfisher Lake First Nation, (3) Wawakapewin First Nation, (4) Kasabonika Lake First Nation, (5) Wapekeka First Nation, (6) Kitchenuhmaykoosib Inninuwug, (7) North Caribou Lake First Nation, (8) Muskrat Dam First Nation, (9) Bearskin Lake First Nation, and (10) Sachigo Lake First Nation.

[11] (1) Pikangikum First Nation, (2) Poplar Hill First Nation, (3) Deer Lake First Nation, (4) Sandy Lake First Nation, (5) North Spirit Lake First Nation, and (6) Keewaywin First Nation.

[12] The Red Lake Remote Connection Lines include approximately 113 km of what was an approximately 117 km line that the Applicant originally constructed, and until May 12, 2023 operated on an interim basis, as a distribution line running from a connection point on Hydro One's distribution system in Red Lake to a switching station serving the Pikangikum First Nation. Approximately 95 km of the 113 km portion of the line was

The Remote Connection Lines will help address the significant limitations associated with the current electricity supply in the remote Indigenous communities, which severely impacts community infrastructure, economic development and quality of life, and leads to significant environmental and health risks.

2. Project Design Changes

As a condition of approval, the LTC Decision required WPLP to advise the OEB of any proposed material changes in the Transmission Project. WPLP has previously advised the OEB of two changes, first relating to the relocation of a substation, and second to a change in the type of structure to be used for the 230 kV and 115 kV line segments. As noted below, the OEB confirmed that neither of these changes was material.

(i) Relocation of Wataynikaneyap SS

On July 22, 2019, WPLP advised the OEB that following additional engineering and coordination with HONI, it had decided to shift the location of the Wataynikaneyap SS (which is located at the south end of the Line to Pickle Lake near Dinorwic) by approximately 620 meters to the northwest. This relocation required a corresponding extension of the 230 kV Line to Pickle Lake by the same distance, running parallel to HONI's existing D26A 230 kV circuit. This change in scope was made in consideration of constructability, soil conditions and site access and did not affect any new landowners or additional land parcels. On August 8, 2019, the OEB confirmed that the change was not material.[13]

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constructed to a 115 kV standard but, during the interim period, was supplied by Hydro One's 44 kV system and was therefore only capable of operating at 44 kV. Approximately 18 km of the 113 km portion of the line was constructed to a 25 kV standard. As contemplated by the OEB's Decision and Order in EB-2018-0190, the 18 km segment is now deemed to be part of the Transmission System, and the 95 km portion of the line was converted to a transmission voltage as of May 12, 2023 by changing its connection point from Hydro One's 44 kV distribution system to WPLP's Red Lake Switching Station. Approximately 5 km of the distribution line does not form part of the WPLP Transmission System.

[13] Letter from OEB to WPLP re Post-Approval Modifications (EB-2018-0190), August 8, 2019 (https://www.rds.oeb.ca/CMWebDrawer/Record/649128/File/document).

(ii) Use of Lattice Steel Structures

The physical design of the transmission lines, as set out in the LTC Application, contemplated the use of H-frame wood pole structures for the 230 kV Line to Pickle Lake, as well as for most 115 kV segments of the Remote Connection Lines, with single-pole wood structures for the 44 kV and 25 kV segments. Through the competitive EPC contracting process (see Exhibit B-1-2), it became evident to WPLP that the use of lattice steel structures for the 230 kV and 115 kV components of the project would be comparable in cost to the use of H-frame wood pole structures, which was not previously expected. In addition to a small initial cost savings as compared to the wood structures, the use of lattice steel structures offered WPLP important advantages in terms of reduced construction schedule risk (due to the ability to assemble the structures at centralized locations), reliability benefits and reduced land disturbance. On August 16, 2019, WPLP advised the OEB of its proposed use of lattice steel structures and on August 23, 2019, the OEB confirmed that this proposed change was not material.[14] This change occurred during the course of negotiating the EPC contract with the preferred proponent and enabled the contract to ultimately be executed based on the planned use of the lattice structures.

3. Additional Project Changes

In the LTC Decision, the Board recognized that WPLP would complete final engineering, procurement, construction and commissioning of the Transmission Project through a competitively tendered EPC contract. While the overall scope of work and the design basis for the Transmission Project are set out in the EPC contract, the EPC contractor has been required to complete final engineering and design activities as part of its scope of work. As discussed in the 2023 revenue requirement application, throughout this process, and in consideration of ongoing engagement efforts, a number of additional project changes have been identified, as discussed below. While there have been no further changes since the 2023 revenue requirement application, as final engineering and design activities continue to progress in parallel with ongoing engagement

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[14] Letter from OEB to WPLP re Post OEB Approval Design Modifications (EB-2018-0190), August 23, 2019 (https://www.rds.oeb.ca/CMWebDrawer/Record/650616/File/document).

efforts for segments of the transmission system with later in-service dates, the need for further changes may still arise.

(a) Changes to Design

As a result of the EPC contractor's detailed design and engineering efforts progressing through typical stages of design and review to date, a small number of design changes have occurred. These changes have included additional grounding switches, changes to reactor sizing and placement within substations, which will improve the future operability and maintainability of the Transmission System, including operation during contingencies. Minor changes to specific steel lattice tower types and anchoring components have also been made as line design engineering has progressed from initial design to "Issued for Construction" status. Given that OEB staff did not consider WPLP's earlier design change from wood pole to steel lattice towers to be material, WPLP does not consider any of these further design changes to date to be material.

(b) Changes to Routing

In the Leave to Construct proceeding, WPLP presented its comprehensive process to initially select and subsequently refine the routing for the Transmission Project.[15] This routing process integrated technical and constructability considerations with a comprehensive EA process, informed by continued engagement with potentially impacted Indigenous communities, land users, government agencies and other relevant stakeholders. WPLP maintains a comprehensive engagement program, as described in Exhibit B-1-2, to support Indigenous knowledge and land use protocols being appropriately accounted for during the detailed design and construction phases of the project. WPLP also continues to communicate with a number of government agencies, including the MNRF, MECP and MTO. WPLP has processes in place to verify that appropriate approvals are received from Indigenous communities and appropriate government agencies, prior to committing to any routing refinements.

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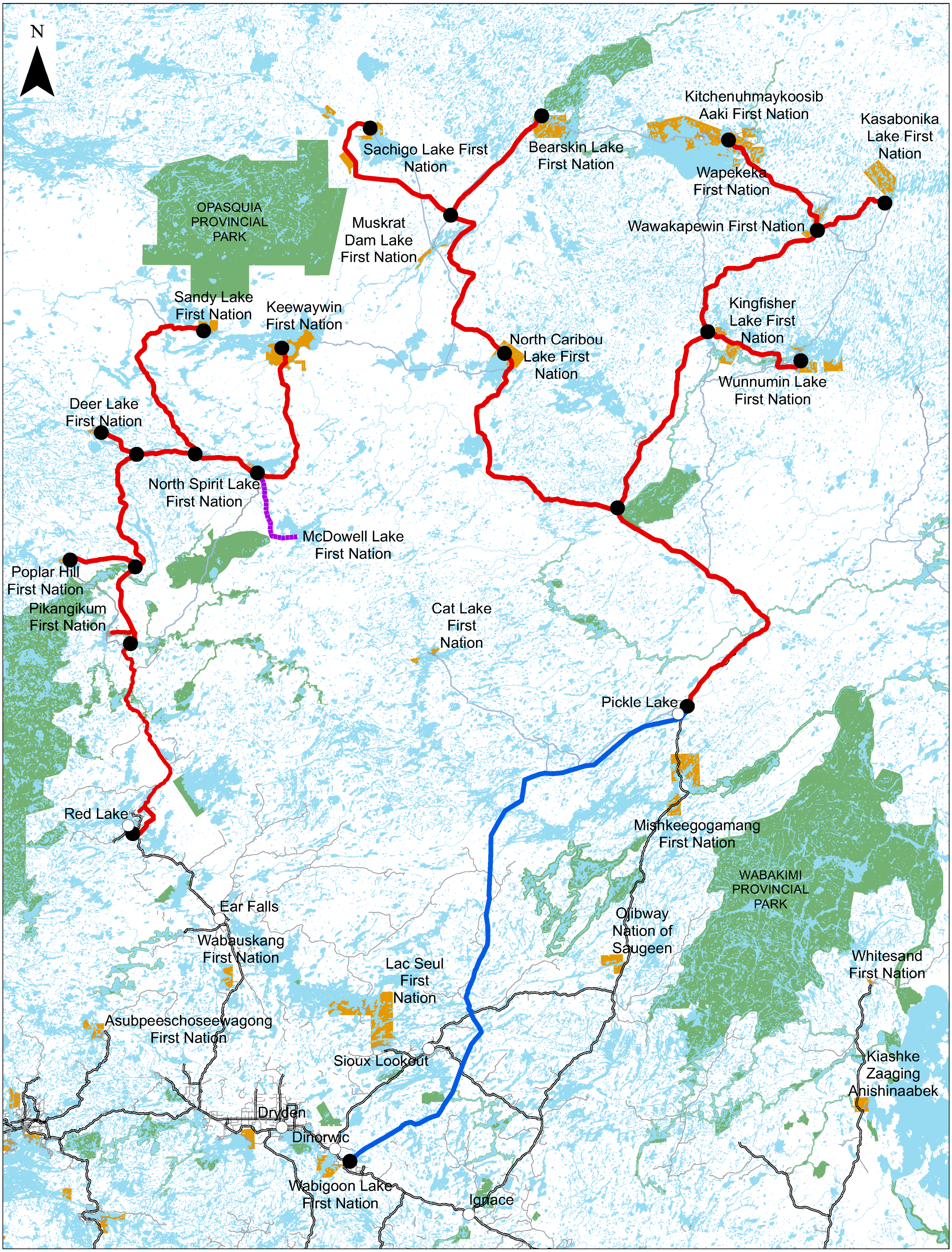
[15] See for example: (a) EB-2018-0190, Exhibit D-3-1, as amended October 5, 2018; (b) WPLP's January 28, 2019 letter advising the OEB of minor routing amendments; and (c) the OEB's January 31, 2019 reply to WPLP, agreeing that the realignments were minor in nature.

As a result of continuous efforts to engage with the affected Indigenous communities, certain routing refinements were made in 2021 and 2022, primarily in five locations: (i) near McInnes Lake (between Poplar Hill SS – Substation R and Deer Lake SS – Substation T); (ii) near Critchell Lake (between Poplar Hill SS – Substation R and Deer Lake SS – Substation T), (iii) between Muskrat Dam TS - Substation E and Sachigo Lake TS - Substation G, (iv) near the Muskrat Dam peninsula, and (v) near the Fawn River in the vicinity of Kitchenuhmaykoosib Inninuwug (KI) to avoid culturally sensitive areas, which were not previously identified. These changes represented a total net increase of approximately 8 km (or less than 1%) relative to the total project length. The revised transmission line rights-of-way were permitted through a multi-site land use permit issued by the MNRF and through section 28(2) permit amendments where First Nation reserve lands were impacted. Moreover, given that these routing refinements remained within the limits of work identified in the EA process, and did not impact any new land rights holders or landowners, WPLP did not consider the refinements to be material in the context of the obligation to notify OEB staff as set out in the LTC Decision. Since then, there have been no material routing changes.

Please see Exhibit B-1-4 for a description of WPLP’s change management and control process.

Appendix ‘A’ – Transmission System Map



Legend

▬ Line to Pickle Lake	🟦 Waterbody
▬ Remote Connection Lines	═ Arterial Road or Highway
▬ Future Line to McDowell Lake First Nation	─ Local Road
● Substation	─ Winter Road
🟧 First Nation Reserve	
🟩 Provincial Park	

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PROJECT OVERVIEW

REFERENCE

Base Data - MNR LIO, obtained 2020, NTDB
Transmission Routes - Provided by Wataynikaneyap Power PM
First Nation Communities from Indigenous and Northern Affairs Canada (www.ainc-inac.gc.ca)
Produced by Wataynikaneyap Power PM
Projection: Transverse Mercator Datum: NAD 83
Coordinate System: UTM Zone 15

0 12.5 25 50 km

1:750,000

Exhibit B, Tab 1, Schedule 2

Project Planning and Development

PROJECT PLANNING AND DEVELOPMENT

This schedule describes the key elements of WPLP's project planning and development process and provides an overview of the development activities that have been carried out by WPLP since the decision approving WPLP's 2023 revenue requirement was issued on November 29, 2022.

A. Leave to Construct Proceeding

WPLP's Transmission Project planning and development activities were described and considered in detail during the Leave to Construct proceeding. WPLP demonstrated that it had undertaken a comprehensive and rigorous planning and development process to define and execute the Transmission Project, the key elements of which included:

- Comprehensive environmental assessment processes for all aspects of the Transmission Project to identify, minimize and mitigate potential environmental impacts;
- Extensive Indigenous and Métis engagement and stakeholder consultation processes, which provided multiple opportunities for meaningful review and input from affected persons over an extended period;
- Thorough review and in-depth analysis of transmission line routing and facility location options to determine optimal routing and facility locations using best available information, taking into account input received through engagement and consultations, as well as environmental, constructability and cost considerations;
- Rigorous engineering analysis, including from internal resources and with support from a third-party Owner's Engineer, as well as in consultation with the IESO and Hydro One Networks Inc. (HONI), to arrive at a detailed and considered system design that is consistent with the IESO's recommended and supported scope, compatible with the neighboring systems to which it will be connected, and that appropriately balances the needs for safety, reliability, efficiency, operational flexibility and cost minimization;

- System Impact Assessment Reports from the IESO and Customer Impact Assessment Reports from HONI, which have been obtained for all project components to ensure that connection of the Transmission System facilities to the provincial electricity grid will result in no material adverse impacts on the reliability of the integrated power system, or on existing customers connected to HONI' s transmission system; and

- Efforts to minimize the number of directly affected landowners and the impacts of the Transmission Project on those landowners through considerations of routing and design, and providing fair offers to such landowners where needed to enable WPLP to secure in a timely manner all of the land rights required to construct, own and operate the Transmission Project facilities.

The OEB, in the LTC Decision, found that:

- WPLP demonstrated that its cost estimates were developed through an appropriate process according to a well-defined scope, and that it took appropriate steps to find cost efficiency measures and ensure that the costs of the Project would be well managed;[1]

- WPLP's approach to the Transmission Project, including its competitive tendering of the EPC contract and the retention of a third-party Owner's Engineer to assist with procurement and project management processes, was a reasonable way to manage the risks associated with the Transmission Project costs;[2]

- there will be no adverse impacts on the integrated power system and consumers with respect to the reliability and the quality of electricity service from the Transmission Project, provided that the requirements specified in the Final System Impact Assessments and Customer Impact Assessments are implemented;[3] and

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[1] OEB, LTC Decision and Order, EB-2018-0190, April 1, 2019 (Revised April 29, 2019), p. 12.

[2] LTC Decision, p. 12.

[3] LTC Decision, p. 14.

- there were no concerns with respect to WPLP's land requirements or land rights acquisition process.[4]

B. Post-Leave to Construct Planning and Development Activities

WPLP has continued to progress in all areas of project planning, development and construction since completion of the Leave to Construct proceeding in April 2019, and since completion of the 2023 revenue requirement proceeding in November 2022. The following describes WPLP's key activities and achievements during each of these periods, including with respect to EPC contracting, financing, federal funding arrangements, permits and approvals, land rights acquisition, coordination with HONI and HORCI, engagement with Indigenous and Métis communities, the facilitation of back-up generation, and coordination with the IESO.

1. EPC Contracting

In the LTC Decision, the Board recognized that: (i) WPLP would complete final engineering, procurement, construction and commissioning of the Transmission Project through a competitively tendered Engineering, Procurement and Construction ("EPC") contract, (ii) WPLP had retained an Owner's Engineer to provide increased granularity and accuracy of the cost estimate in preparation for the EPC tendering, evaluation and selection process, and (iii) the Owner's Engineer's mandate would include a requirement to refine the contingency. On that basis, the OEB found that competitive tendering of the EPC contract and the retention of a third-party Owner's Engineer to assist with procurement and project management processes was a reasonable way to manage the risks associated with the Project costs.[5]

More particularly, WPLP's Owner's Engineer, Hatch Ltd. ("Hatch"), was engaged through a competitive process in Spring 2018. With assistance from Hatch, WPLP ran a pre-qualification process to identify qualified and interested firms to participate in its EPC contracting process. The pre-qualification process included the issuance of a Request for Expressions of Interest and

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[4] LTC Decision, p. 19.

[5] LTC Decision, pp. 6 and 12.

Qualifications, which identified eight potential proponents. This was followed by safety, performance and bench strength reviews, which narrowed the group down to four pre-qualified proponents.[6] The pre-qualification process was completed in September 2018. The four pre-qualified proponents were then permitted to participate in WPLP's Request for Proposals ("RFP") process for EPC services.

In parallel with running the pre-qualification process, with Hatch's assistance, WPLP developed its RFP, which was issued to the four pre-qualified proponents on November 2, 2018. Through Wataynikaneyap Power PM Inc. (the "Project Manager"), WPLP was also assisted in developing and administering the RFP by Fortis subsidiary ITC Holdings Corp. ("ITC"), which is the largest independent electricity transmission company in the United States, as well as by Opiikapawiin Services ("OSLP") and the technical departments of the Tribal Councils representing member Indigenous communities within the Participating First Nations. Following a number of RFP addendums to enable proponents to develop higher quality and more competitive proposals, WPLP granted a two-month extension that allowed proponents to submit their responses in mid-April 2019.

The review process included a comprehensive set of evaluation criteria for all components of the RFP and an executive review team, along with sub-teams of experts that included representatives from Hatch, the Project Manager (including ITC) and OSLP. The RFP was structured to enable proponents to bid separately for each of (a) the Line to Pickle Lake (Group 1), (b) the Pickle Lake Remote Connection Lines (Group 2), and (c) the Red Lake Remote Connection Lines (Group 3), and to propose pricing for developing one group, two groups or all three groups. All of the pre-qualified proponents bid for all three portions of the Transmission Project. Valard LP was

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[6] As described in a September 18, 2018 news release, the pre-qualified proponents were Forbes Bros. Ltd. (Pennecon), Power North Contractors JV (PowerTel, Kiewit and SNC-L), Valard Construction LP, and Voltage Power Ltd. (Sigfusson, Anishnawabe Construction Corporation). See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-announces-pre-qualified-proponents-to-receive-engineering-procurement-construction-request-for-proposal-packages-epc-rfp-for-phase-1-2-of-the-project

identified as the preferred proponent for all three groups in early July 2019, at which point the other proponents were notified and contract negotiations with Valard LP commenced.

Valard LP made the lowest cost proposal for all three groups. In part, this contributed to the selection of Valard LP as the preferred proponent for all three portions of the Transmission Project. Upon receiving confirmation from OEB staff on August 23, 2019, that changing to a lattice tower design was not a material change under the LTC Decision[7], the final EPC contract was executed with Valard LP and was announced on September 10, 2019.[8]

On October 25, 2019, coinciding with its achievement of financial close (see below), WPLP issued a formal Notice to Proceed to Valard LP under the EPC contract. Between the execution of the EPC contract and the filing of the 2023 revenue requirement application on July 6, 2022, WPLP approved 49 change orders related to design changes and routing refinements. These change orders are described in WPLP's prior two rate applications.[9] Since July 6, 2022, WPLP has approved 13 change orders related to design changes, contract terms and routing changes that are further described in Sections C.2 of Exhibit B-1-5. The construction schedule and cost changes resulting from completion of the EPC procurement process, as well as change orders and other factors, are discussed in Exhibits B-1-3 and B-1-5, respectively. COVID costs are discussed separately in Exhibit H-2-2.

2. Financing

As noted above, coinciding with its issuance of Notice to Proceed to Valard LP under the EPC contract on October 25, 2019, WPLP achieved another significant development milestone when it closed on its project financing. Financial close reflected the completion of a negotiated Common Terms and Inter-Creditor Agreement ("CTIA") with the Province of Ontario and a group of Senior Bank Lenders to provide total project financing of up to $2.02 billion, consisting of up to $1.34

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[7] OEB Letter, August 23, 2019 (EB-2018-0190) http://www.rds.oeb.ca/HPECMWebDrawer/Record/650616/File/document.

[8] See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-awards-engineering-procurement-construction-contract-to-valard-lp.

[9] See: EB-2021-0134, Exhibit B-1-2 and Exhibit B-1-5, and EB-2022-0149, Exhibit B-1-2 and Exhibit B-1-5.

billion from Ontario (the "Ontario Facility") and up to $680 million from the Senior Bank Lenders (the "Senior Bank Facility"). For clarity, WPLP is not currently forecasting to require the entire amount of available financing. However, it secured financing that would cover a combination of scenarios in consideration of pre-COVID-19 cost increases, interest rate increases and construction delays.[10] WPLP's financing process and arrangements are described in greater detail as part of the evidence on WPLP's cost of capital in Exhibit G, Tab 2, Schedule 1.

3. Federal Funding Arrangements

In EB-2018-0190, WPLP described the federal funding contemplated for the Transmission Project, which resulted from a March 12, 2018 Memorandum of Understanding between WPLP, Canada, and Ontario.[11] Subsequent to the LTC Decision, on July 3, 2019, WPLP, Canada and Ontario signed definitive documents regarding the funding framework for the Transmission Project and a formal announcement was made on July 22, 2019.[12] While the provision of funding remains conditional on appropriation by Parliament, the definitive documents solidify the mechanics by which the funding would be provided upon appropriation. WPLP assumes for the purpose of this Application, and based on the construction schedule, that the distribution of funds will occur on December 31, 2024, following the later of: (a) the OEB's Decision and Order in respect of the current application; or (b) completion of construction and receipt of funds by the Trustee.

Since the actual date that WPLP will receive the contribution in aid of construction ("CIAC") may be earlier or later than December 31, 2024, WPLP is requesting approval to establish a symmetrical new variance account to record the revenue requirement impact of that timing difference. Under the proposed Federal CIAC Variance Account (FCVA), if the CIAC is received earlier than December 31, 2024, WPLP would seek to refund the revenue requirement impact to HORCI as

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[10] As discussed in Exhibit H-2-2, WPLP continues to be engaged in commercial discussions with its EPC contractor, Valard, regarding costs under the EPC contract in relation to COVID impacts and related matters. The outcome of the discussions could impact the amount of financing required. Moreover, as discussed in Exhibit H-1-1, WPLP is seeking to establish a new deferral account to record costs incurred and to be incurred in respect of the amounts that are the subject of the commercial discussions that are ongoing with Valard.

[11] EB-2018-0190, Exhibit J-1-2.

[12] See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-and-government-of-canada-formalize-support-for-provinces-largest-first-nations-led-transmission-project.

the sole customer on its Remote Connection Lines, and if the CIAC is received later than December 31, 2024, WPLP would seek to recover the revenue requirement impact from HORCI in a future rate application. Further details about how the federal funding will be applied and the proposed FCVA are set out in Exhibits I-4-1 and H-1-1, respectively.

4. Permits and Approvals

WPLP's progress with respect to permits and approvals since the LTC and since completing the prior two revenue requirement proceedings has been focused on the environmental assessments for the Line to Pickle Lake and Remote Connection Lines, species protection and the *Far North Act*, as follows.

In EB-2018-0190, WPLP described the two distinct environmental assessment ("EA") processes for the Transmission Project: (i) an Individual EA process under the provincial *Environmental Assessment Act* ("EA Act") for the Line to Pickle Lake, and (ii) a comprehensive engagement plan and effects assessment for the Remote Connection Lines to address, in an integrated manner, all provincial class EA requirements under the EA Act and certain additional federal environmental requirements from Indigenous Services Canada (formerly Indian and Northern Affairs Canada) ("ISC") based on its consideration of environmental effects.[13]

On June 21, 2019, following multiple rounds of community engagement and comments from various government ministries and Indigenous and Métis communities, the Minister of the Environment, Conservation and Parks ("MECP"), with support from the Lieutenant Governor in Council ("LGIC"), approved the Individual EA for the Line to Pickle Lake with conditions. Following the MECP's decision, WPLP identified changes to optimize the design and reduce the overall footprint of the Line to Pickle Lake. Generally, these changes had the effect of reducing potentially adverse environmental effects. To give effect to the changes, WPLP amended the final EA Report for the Line to Pickle Lake and, on September 12, 2019, the MECP accepted the

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[13] EB-2018-0190, Exhibit I-1-1

changes. With the acceptance of the changes, the EA for the Line to Pickle Lake was deemed complete.

Following multiple rounds of community engagement and comments from various government ministries and Indigenous and Métis communities, WPLP satisfied all provincial class EA requirements for the Remote Connection Lines and, in July 2019, the Minister of Natural Resources and Forestry ("MNRF") and the MECP issued their respective Statements of Completion, thereby approving the EA for the Remote Connection Lines. Following this provincial approval, but before obtaining federal approval from ISC, WPLP identified certain refinements to the Remote Connection Line's 115 kV corridors that had the effect of reducing the overall footprint of the project and optimizing the design to align with future community infrastructure projects. To implement these changes, WPLP issued an Addendum to the Final Environmental Study Report ("ESR") for public comment and for MNRF, MECP and ISC approval. On August 2, 2019, WPLP received provincial approval for the Addendum. Following this provincial approval, in September 2019, ISC completed its environmental review of the Remote Connection Lines, inclusive of the changes set out in the Addendum, and concluded that, taking into account the proposed mitigation measures, the Remote Connection Lines portion of the Transmission Project is not likely to cause significant adverse environment effects. With this approval, the EA for the Remote Connection Lines was deemed complete.

As described in the 2023 revenue requirement application, with the advancement of the Project through community engagement and detailed design, WPLP continues to engage with Indigenous communities, land users, other relevant stakeholders and agencies. As a result of these engagements, WPLP may receive input that may require amendments to its EA permits. In 2021, as a result of input received from Indigenous communities in connection with the Remote Connection Lines, WPLP made three amendments to its ESR. First, in April 2021, WPLP amended its ESR to reflect minor routing changes in the vicinity of McInnes Lake and Critchell Lake within the Whitefeather Forest area northeast of Pikangikum First Nation and Poplar Hill First Nation, and changes to the line leading towards Sachigo Lake First Nation. Second, in June 2021, WPLP amended its ESR to reflect minor routing changes at two locations along the connections approaching Muskrat Dam First Nation and Bearskin Lake First Nation. Third, in July 2021, WPLP amended its ESR to reflect minor routing changes along the connection approaching Kasabonika Lake First Nation and a minor relocation of the substation at Kasabonika Lake First Nation. For each of these changes, WPLP sought and received MECP's approval to amend its ESR permit. While these changes necessitated the ESR permit amendments, they are not considered material in the context of the LTC decision as these changes did not affect any new landowners or materially impact the overall cost of the Project. There have been no further changes since the 2023 revenue requirement application requiring amendments to EA permits.

(a) Species Protection

During the EA processes, WPLP determined that construction, operation and maintenance activities associated with the Transmission Project might affect certain species at risk or their habitats. This triggered application of the Ontario *Endangered Species Act* ("ESA") and the federal *Species at Risk Act* ("SARA") as each Act is applicable within the Transmission Project footprint. WPLP was required to apply for authorization in order to proceed with construction activities that might otherwise be prohibited under the ESA and/or SARA. In October 2019, WPLP received the ESA and SARA permits, with conditions aimed at protecting and mitigating the effects of the Transmission Project on certain species at risk. As the Transmission Project progresses, WPLP continues to update its ESA permit by way of minor amendments, where required, to reflect the most up to date information available in relation to its activities aimed at protecting and mitigating the effects of the Transmission Project on certain species at risk and habitats.

(b) Far North Act

As discussed in EB-2018-0190, WPLP and the MNRF established a technical working group to consider how WPLP could meet the requirements of the *Far North Act* ("FNA") and to determine an appropriate approach for meeting those requirements.[14] Given the scale and scope of the Transmission Project, and the number and geographic range of areas that had and had not started their FNA planning processes, the technical working group determined that an appropriate

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[14] EB-2018-0190, Exhibit F-2-1.

approach to meeting the requirements of the FNA was for WPLP to request an Order from the LGIC, pursuant to subsection 12(4) of the FNA, declaring the Transmission Project to be in the social and economic interests of Ontario. WPLP followed this approach and submitted its request, along with supporting information. On August 16, 2019, the LGIC determined that the Transmission Project is in the social and economic interests of Ontario. In doing so, the LGIC exempted WPLP from the further application of the FNA.

5. Land Rights Acquisition

WPLP has acquired all of the land rights required for purposes of the Transmission Project. As discussed in EB-2018-0190, these include various land rights required from private landowners, as well as rights in respect of public lands over which various federal, provincial and municipal authorities assert jurisdiction.[15]

In particular, WPLP has acquired: (i) all required easements on private lands; (ii) all required permits under section 28(2) of the *Indian Act*, which have been signed off by the affected First Nations and the federal government; (iii) all required Land Use Permits for transmission line right-of-way and substations located on lands over which the Province of Ontario, through the MNRF and the Ministry of Transportation ("MTO"), asserts authority;[16] and (iv) a required easement on land owned by the Corporation of the Municipality of Red Lake. In addition, upon further investigation, WPLP and its EPC contractor, Valard LP, have verified that no other municipally owned lands or roads under the control of local roads boards are affected by the Transmission Project.

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[15] EB-2018-0190, Exhibit F-2-1.

[16] Although all required Land Use Permits have been secured, due to the fact that Land Use Permits are not assignable to WPLP's lenders, WPLP was required to convert its Land Use Permits into a License of Occupation to finalize its financing arrangements. Upon completion of construction, the License of Occupation will be converted into an easement. WPLP has secured a Multisite Land Use Permit to capture minor routing refinements as they are finalized for different segments of the Transmission Project. License of Occupation mapping for these minor routing refinements will be produced to add these locations to WPLP's License of Occupation. To the extent that any of the changes being contemplated may be material, WPLP will notify the OEB in accordance with the conditions of its LTC.

Independent of the conventional land rights discussed above, WPLP has followed the Anishinabe and Anishinninuwug land sharing and traditional protocols, in respect of WPLP's use of land covered by Treaties 3, 5 and 9.[17]

WPLP has also worked with Valard, the MECP and the MNRF to secure all Water Crossing Permits and Work Permits that are required for access roads based on the EPC contractor's work schedule. In addition, Valard has prepared all detailed engineering design drawings required to secure the necessary MTO Encroachment Permits and crossing agreements in respect of Canadian National Railway and Canadian Pacific Railway crossings. The MTO has determined that license agreements will not be required for WPLP's planned crossings of MTO controlled roads and, instead, Encroachment Permits have been issued.

As discussed in the 2023 revenue requirement application and further in Exhibit B-1-1, in 2021, WPLP made certain routing refinements to incorporate input received from the affected Indigenous communities and avoid culturally sensitive areas, which may not have been previously identified. The revised transmission line rights-of-way were permitted through a multi-site land use permit issued by the MNRF and through section 28(2) permit amendments where First Nation reserve lands were impacted. There have not been any material routing refinements since the 2023 revenue requirement application.

6. Coordination with HONI and HORCI

In parallel with the EPC contracting process described above, WPLP worked with Hatch (its Owner's Engineer) and various representatives of HONI to advance a number of project development milestones including: (a) completing preliminary engineering of substation layouts and interconnections between the HONI and WPLP transmission systems at each of Dinorwic, Pickle Lake, and Red Lake; (b) coordinating land rights, access requirements and EA approvals in relation to these stations; and (c) refining station locations and footprints in consideration of permitting and approval requirements.

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[17] Please refer to Exhibit F-1-1 of EB-2018-0190 for additional discussion of land sharing and traditional protocols.

Following WPLP's selection of Valard as the preferred proponent in the EPC RFP, WPLP and Hatch continued to coordinate engineering efforts with HONI, further advancing station engineering efforts in consideration of enhanced and updated information available from the EPC proposal, as well as consideration of preliminary construction schedules provided in the proposal. After issuing the Notice to Proceed to Valard, formal project teams were established to finalize engineering and design with respect to interconnections with HONI.

Coordination with HORCI following the LTC Decision has primarily focused on facilitating backup supply arrangements (see Section 8 below) and advancing agreements and arrangements for the transfer of distribution system assets to HORCI for communities currently served by Independent Power Authorities (IPAs). IPA transfer work has focused on advancing contractual agreements and permitting, as well as preparing and issuing design and construction tender packages for the necessary distribution system and facilities upgrades in each community. OSLP, in collaboration with ISC and HORCI, completed the development of template Asset Transfer Agreements and template permits under Section 28(2) of the *Indian Act* in January 2020.[18] Those templates were reviewed with all IPA communities and their respective Tribal Councils. Design and construction tendering processes have been completed for all six communities that are currently served by IPAs. Target completion dates for all construction activities and other transfer requirements and conditions are aligned at or before the target in-service dates for each community, and the Asset Transfer Agreements and Section 28(2) permits will be finalized on a rolling basis in parallel with the completion of those activities for each community.

Since the 2023 revenue requirement application, WPLP has continued to coordinate with HONI on matters relating to each of the three locations where WPLP's transmission system connects with HONI's transmission system. Similarly, WPLP has worked with HORCI to coordinate procurement, construction, commissioning and energization activities for distribution delivery points, with a focus on the communities that connected in 2022 and will be connecting in 2023.

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[18] HORCI continues to work with the IPA communities on their respective Understanding and Conveyance Agreements. A copy of the most recent Indigenous Services Canada report on IPA and Backup Power was filed by WPLP as part of its Semi-Annual Report dated April 17, 2023, pursuant to EB-2018-0190.

WPLP's engagement and coordination activities with HONI and HORCI have also included the execution of transmission connection agreements, confirmation of settlement processes, and completion of relevant IESO registration processes.

Pursuant to the approved Settlement Agreement in EB-2022-0149, WPLP has worked with HORCI to enhance coordination of community connection processes for communities connecting in 2023 and 2024. In particular, with respect to IPA communities connecting in 2023, WPLP has coordinated with HORCI to ensure that WPLP's assets are energized in a manner that facilitates IPA asset transfer and connection activities. WPLP has also communicated with IPA communities to ensure consistent messaging on IPA transfer requirements and associated timelines for grid connection following the completion of those requirements.

7. Indigenous and Métis Engagement

An overview of WPLP's Indigenous and Métis engagement is provided in Exhibit A-6-1. The following summarizes key developments relating to Indigenous and Métis engagement since the 2023 transmission rate application. Since the 2023 revenue requirement application, WPLP with the assistance of OSLP has continued to engage and communicate with potentially impacted Indigenous and Métis communities on a variety of issues, including but not limited to routing changes, permanent land access plans, permitting work, back-up power, employment and training opportunities, and IPA transfers. In particular, between June 30, 2022 and February 28, 2023, WPLP with support from OSLP held:

- Eight (8) in-person meetings with communities, during which the discussions related to topics that included permanent access for operational purposes for the project, updates on project status, health and safety, permitting, land access, IPA transfer, backup power, and Indigenous participation, along with community-specific questions and feedback;

- One (1) community-specific radio show to provide updates on the Transmission Project, Health and Safety, Permitting, Operations and Maintenance, and Indigenous participation, as well as to provide Participating First Nation members with an opportunity to call in to ask questions;

- One (1) community-specific teleconference to provide a general overview of the Wataynikaneyap Transmission Project, where members had the opportunity to call in to ask questions;
- One (1) meeting with Community leadership specifically dedicated to discussing COVID-19 and the removal of vaccine requirements on the Project;
- One (1) meeting with Community leadership specifically dedicated to discussing other specific matters on the Project; and
- Sixteen (16) teleconferences and in-person meetings to address community-specific project related issues, including with respect to access roads and winter roads.

In addition, WPLP and OSLP continue to produce a monthly update newsletter and provide information, updates and opportunities via their respective websites and social media pages. WPLP continues to engage with Indigenous communities and the Métis Nation on regulatory requirements as required, including the circulation of documents for review and input (archaeology, environmental assessment, permitting), circulation of quarterly environmental updates, and notification of sightings of species at risk.

8. Facilitation of Back-up Supply

Further to the OEB's decision in EB-2018-0190, WPLP is required to provide regular updates to the Board, through its semi-annual reports, on its efforts to facilitate the development of back-up electricity supplies to the connecting communities. Please refer to WPLP's most recent semi-annual report (dated April 17, 2023) for a description of the status of those efforts and the activities most recently undertaken by WPLP (through OSLP) to facilitate back-up supplies.

WPLP also notes that, in response to its semi-annual report filed on April 15, 2021, the OEB requested that WPLP file a copy of its finalized backup power plan (the “Backup Power Plan”) and that WPLP provide opinions on the sufficiency of the backup power plan from HORCI and the IESO. The OEB’s letter further requested explanations as to (a) why the Backup Power Plan provides for backup supply coverage only of critical assets in three communities, and (b) the plans for funding the long-term costs associated with the supply of back-up power to the connecting communities. On July 15, 2021, WPLP responded to the OEB’s request and provided the requested information. The OEB subsequently requested, by way of a letter dated July 23, 2021, that WPLP facilitate a request to the Backup Power Working Group (“BPWG”) for confirmations in respect of certain aspects of the Backup Power Plan. WPLP has requested that the BPWG provide confirmation of those aspects, which relate to reliability levels and the ability to supply load identified in each community’s Emergency Response Plan. WPLP continues to work with BPWG to address the OEB’s request for additional information. The BPWG has provided information to assist in responding to the OEB’s request. An update is provided as part of the semi-annual report dated October 15, 2022.

9. Coordination with the IESO

Prior to energizing the Line to Pickle Lake in August 2022, WPLP executed a Transmission Operating Agreement with the IESO, which is substantially similar to the terms of the operating agreements the IESO has entered into with all other Ontario transmitters. This agreement defines those of WPLP’s transmission facilities that are part of the IESO-Controlled Grid and sets forth the various responsibilities of the IESO and WPLP with respect to the secure and reliable use and operation of WPLP’s transmission facilities. Pursuant to this agreement, WPLP regularly interacts with IESO on matters related to equipment outage approvals, real-time operation and control, as well as system operating procedures and constraints. WPLP also interacts with IESO as required on matters relating to customer inquiries and requests for connection. Since early 2020, WPLP has also coordinated with the IESO to complete various requirements of the IESO’s transmission connection process, including authorizations for market and program participation, facility and equipment registrations, and equipment commissioning. WPLP has submitted facility registrations for all substations coming into service in 2023 and is in the process of completing equipment registration requirements for major equipment within those stations, as well as completing all other IESO registration requirements prior to energizing each station. Due to the nature of the IESO's facility and equipment registration processes, WPLP expects to continue to work through these requirements until Summer 2024, one station at a time, in the months leading up to the energization of each station that is not yet energized.

Exhibit B, Tab 1, Schedule 3

Project Schedule

PROJECT SCHEDULE

This section describes the current construction schedule, including the sequencing of in-service dates for all project components and segments. In addition, WPLP identifies and explains the causes of changes in the schedule relative to the schedule that was presented in the 2023 revenue requirement proceeding, and discusses schedule risks, contingency and risk mitigation.

A. Prior Transmission Project Schedules

WPLP provided regular updates to its forecasted project schedule through semi-annual reports filed pursuant to the OEB's Decision and Order in EB-2016-0262 until July 15, 2019.[1] Commencing October 15, 2019, WPLP has instead provided semi-annual reports pursuant to the OEB's Decision and Order in EB-2018-0190, which did not require information updates regarding the Transmission Project schedule.[2]

In its 2022 revenue requirement application, WPLP presented the then current Transmission Project schedule along with the changes in the schedule relative to that which was presented in the Leave to Construct proceeding. In its 2023 revenue requirement application, WPLP presented the most recent estimates then available of the energization dates for each community with comparisons to the estimated energization dates that were presented in the April 18, 2022 Semi-Annual Report.

Pursuant to the Settlement Agreement in EB-2021-0134, WPLP agreed to include information relating to the expected connection dates for communities not yet connected to WPLP's transmission system in its semi-annual reports that it continues to be required to file pursuant to the OEB's directions in EB-2018-0190. Furthermore, pursuant to the Settlement Agreement in

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[1] The OEB's Decision and Order in EB-2016-0262 authorized WPLP to establish a deferral account to record project development costs, and required WPLP to file semi-annual reports addressing project progress, costs, schedule and risks.

[2] The OEB's Decision and Order in EB-2018-0190 granted Leave to Construct and required WPLP to file a semi-annual report regarding its CWIP account and three associated sub-accounts, as well as to report on the progress of backup supply arrangements for each community to be connected.

EB-2022-0149, WPLP agreed to provide certain additional information on target community connection dates and notices regarding any changes to the construction schedule.

WPLP's Semi-Annual Report, filed on April 17, 2023, provided the most recent estimates then available regarding the energization dates for each community not yet connected to WPLP's transmission system. WPLP's Semi-Annual Report reflected a November 2022 construction schedule, which had been provided by its EPC contractor. Subsequently, on May 30, 2023, WPLP received a further updated construction schedule from its EPC contractor reflecting all factors known as of that date. That schedule represents the most current available construction schedule and has therefore been used as the basis for this application.

B. Current Construction Schedule

Table 1, below, presents WPLP's current estimates of the energization dates for each of the remote communities, along with comparisons to the estimated energization dates that were presented in the April 15, 2023 Semi-Annual Report. Descriptions of the reasons for variances follow.

Table 1 – Expected Energization Dates by Community

Community	Estimated Date from April 17, 2023 Semi Annual Report	Current Estimated Date	Difference (Months)
Pikangikum	May-23	May-23	-
Wunnumin Lake	May-23	May-23	-
Muskrat Dam	Jul-23	Jul-23	-
Bearskin Lake	Jul-23	Jul-23	-
Wawakapewin	Jul-23	Jul-23	-
Kasabonika Lake	Aug-23	Aug-23	-
Sachigo Lake	May-24	Nov-23	(6)
KI + Wapekeka	Apr-24	Apr-24	-
Poplar Hill	Apr-24	Apr-24	-
Deer Lake	May-24	May-24	-
Sandy Lake	Jun-24	Jun-24	-
North Spirit Lake	Jul-24	Jul-24	-
Keewaywin	Aug-24	Aug-24	-

The work performed during the 2023 winter construction season in Group 2 was on schedule, meeting the project milestone for all of Group 2 (segments North of Pickle Lake) foundation installations to be complete. This milestone allowed construction to be accelerated on predecessor activities including erection and stringing of the transmission line segment for Sachigo Lake First Nation.

Table 2, below, presents WPLP’s current in-service schedule by line segment and station.

Table 2 – In-Service Schedule by Line Segment and Station

Asset Designation	Description	Current Forecast In-Service Date
Line to Pickle Lake		
Line W54W	230 kV - Dinorwic to Pickle Lake	12-Aug-22
Station A	Wataynikaneyap SS (Dinorwic)	12-Aug-22
Station B	Wataynikaneyap TS (Pickle Lake)	12-Aug-22
Pickle Lake Remote Connection Lines		
Line WBC	115 kV - Pickle Lake to Ebane/Pipestone SS	5-Oct-22
Line WCJ	115 kV - Ebane/Pipestone SS to Kingfisher Lake TS	8-Nov-22
Line WJI	44 kV - Kingfisher Lake TS to Wunnumin Lake TS	25-May-23
Line WJK	115 kV - Kingfisher Lake TS to Wawakapewin TS	19-Jul-23
Line WKL	44 kV – Wawakapewin TS to Kasabonika Lake TS	16-Aug-23
Line WKM	115 kV – Wawakapewin TS to KI-Wapekeka TS	26-Apr-24
Line WCD	115 kV - Ebane/Pipestone SS to North Caribou Lake TS	5-Oct-22
Line WDE	115 kV - North Caribou Lake TS to Muskrat Dam TS	7-Jul-23
Line WEF	115 kV - Muskrat Dam TS to Bearskin Lake TS	7-Jul-23
Line WEG	115 kV – Muskrat Dam TS to Sachigo Lake TS	29-Nov-23
Line D1	25 kV – North Caribou Lake TS to HORCI 25 kV	5-Oct-22
Line E1	25 kV – Muskrat Dam TS to HORCI 25 kV	7-Jul-23
Line F1	25 kV – Bearskin Lake TS to HORCI 25 kV	7-Jul-23
Line G1	25 kV – Sachigo Lake TS to HORCI 25 kV	29-Nov-23
Line I1	25 kV – Wunnumin Lake TS to HORCI 25 kV	25-May-23
Line J1	25 kV – Kingfisher Lake TS to HORCI 25 kV	8-Nov-22
Line K1	25 kV – Wawakapewin TS to HORCI 25 kV	19-Jul-23
Line L1	25 kV – Kasabonika Lake TS to HORCI 25 kV	16-Aug-23
Line M+/M-	25 kV – KI-Wapekeka TS to HORCI 25 kV	26-Apr-24
Substation C	Ebane/Pipestone SS	5-Oct-22
Substation D	North Caribou Lake TS	5-Oct-22
Substation E	Muskrat Dam TS	7-Jul-23
Substation F	Bearskin Lake TS	7-Jul-23

Substation G	Sachigo Lake TS	29-Nov-23
Substation I	Wunnumin Lake TS	25-May-23
Substation J	Kingfisher Lake TS	8-Nov-22
Substation K	Wawakapewin TS	19-Jul-23
Substation L	Kasabonika Lake TS	16-Aug-23
Substation M	KI-Wapekeka TS	26-Apr-24
Red Lake Remote Connection Lines		
Line P1P2	115 kV - Red Lake SS to Existing Pikangikum 44 kV Line	12-May-23
Line WQR	115 kV - Pikangikum TS to Poplar Hill SS	18-Apr-24
Line WRS	115 kV - Poplar Hill SS to Poplar Hill TS	18-Apr-24
Line WRT	115 kV - Poplar Hill SS to Deer Lake SS	16-May-24
Line WTU	115 kV - Deer Lake SS to Deer Lake TS	16-May-24
Line WTZ	115 kV - Deer Lake SS to Sandy Lake SS	16-Jun-24
Line WZW	115 kV - Sandy Lake SS to Sandy Lake TS	16-Jun-24
Line WZV	115 kV - Sandy Lake SS to North Spirit Lake TS	14-Jul-24
Line WVY	115 kV – North Spirit Lake TS to Keewaywin TS	11-Aug-24
Substation P	Red Lake SS	2-Sep-22
Substation Q	Pikangikum TS	12-May-23
Substation R	Poplar Hill SS	18-Apr-24
Substation S	Poplar Hill TS, S1 25kV to HORCI	18-Apr-24
Substation T	Deer Lake SS	16-May-24
Substation U	Deer Lake TS, U1 25kV to HORCI	16-May-24
Substation V	North Spirit Lake TS, V1 25kV to HORCI	14-Jul-24
Substation W	Sandy Lake TS, W1 25kV to HORCI	16-Jun-24
Substation Y	Keewaywin TS, Y1 25kV to HORCI	11-Aug-24
Substation Z	Sandy Lake SS	16-Jun-24

C. Schedule Risks, Contingency and Mitigation

WPLP’s construction schedule has been materially compressed from what was contemplated at the time of signing the EPC contract. As such, the schedule now has less inherent float to manage remaining contingency risks.

WPLP’s key schedule risks generally fall under the following five categories:

- **Material and Equipment Delivery:** Risks that delivery dates for material and equipment could be delayed arriving to Canada, or being shipped within Canada, due to any combination of further COVID-related closures of factories or shipping facilities, or work stoppages beyond the control of WPLP or its EPC contractor.[3]

- **Access Considerations:** Risks that access within the project footprint will be temporarily unavailable due to uncertainty in weather (which impacts winter road availability, the ability to safely use other roads and access trails, and the ability to safely fly materials to certain areas), forest fires or MNRF fire prevention orders, archaeological finds during construction, COVID outbreaks within the general project footprint or nearby communities, or other factors beyond WPLP's control of WPLP or its EPC contractor.

- **Third-Party Factors:** Risks that certain activities in respect of which WPLP and/or its EPC contractor are collaborating or interacting with or otherwise dependent upon third parties (e.g. Hydro One, HORCI, IESO, issuers of various permits, etc.) are delayed due to factors beyond the control of WPLP or its EPC contractor.

- **Routing Changes:** Risks that routing changes are required, based on cultural or environmental sensitivities or constraints that are identified during ongoing engagement activities, or through field observations leading up to construction in each area.[4]

- **Construction Execution:** Risks that COVID-19 impacts construction activity.

In consideration of the schedule risks described above, WPLP and its EPC contractor have a number of risk management processes and mechanisms in place, as further described in Section B of Exhibit B-1-4.

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[3] This risk has been significantly mitigated. As of the date of filing, the majority of equipment is on the Project Site or in Canada. As it relates to equipment not on site (primarily inventory), the war in Ukraine is having an impact on availability and price.

[4] This risk has been significantly mitigated as most of the final routing has been determined and agreed to by the relevant stakeholders and First Nations. There only remain a couple of outstanding routing refinements, primarily around the 25kV and 44kV lines.

Exhibit B, Tab 1, Schedule 4

Project Organization and Execution

PROJECT ORGANIZATION AND EXECUTION

This Schedule sets out WPLP's approach to executing the Transmission Project and the organizational structure it has put in place for this purpose. WPLP's project execution structure reflects its commitment to ongoing engagement and communication with potentially impacted communities, land users and other stakeholders, which is critical to the successful construction of the Transmission Project.[1] Also included in this Schedule are details on the company's role in coordinating and overseeing its contractors, change management processes, cost management, risk and performance management, and its project tracking and reporting practices. In addition, this schedule describes WPLP's plans for transitioning to a structure that will perform and support system operations and maintenance as project segments are placed into service.

A. Transmission Project Organization and Execution

As described in Exhibit B-1-2, WPLP undertook a comprehensive EPC RFP process, which resulted in the execution of an EPC contract with Valard LP ("Valard" or the "EPC contractor"). Valard is generally responsible for all engineering, construction management, procurement and construction activities related to the Transmission Project, including requirements related to Indigenous participation, health and safety, environmental compliance, and quality control, pursuant to the terms of the EPC contract.

To provide an appropriate level of project controls, contract administration, risk mitigation, and general oversight during the construction phase, WPLP has developed a project execution structure that continues to leverage the strengths and experience of its partners[2], supplemented by Hatch in its role as WPLP's Owner's Engineer ("OE"), and Mott MacDonald in its role as Independent Engineer ("IE"). The role of each party in the context of WPLP's project execution structure[3] is

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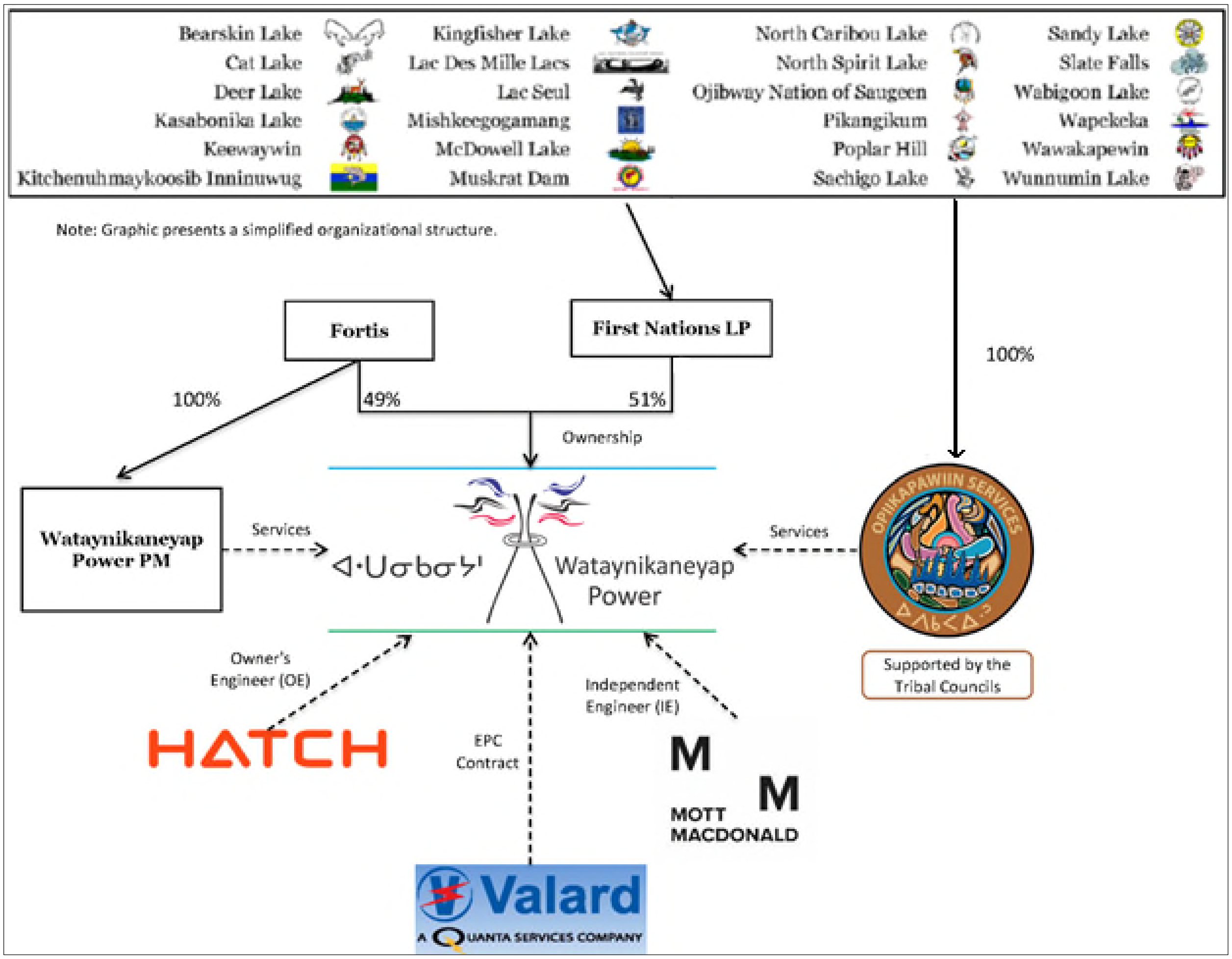
[1] See WPLP's Procurement Policy in Exhibit F-3-1, Appendix 'B' for a description of WPLP's commitment to Indigenous participation and its importance to the Transmission Project.

[2] Including through OSLP and WPPM as service providers, as further explained in Section A of Exhibit B-1-4.

[3] Additional information about WPLP's ownership structure is provided in Exhibit A-4-1.

summarized in Figure 1 below, which is followed by further description of each party's roles and responsibilities related to the Transmission Project.

Figure 1 –Project Execution Structure



1. Opiikapawiin Services LP ("OSLP")

Leveraging the local and traditional knowledge, experience and expertise of the Participating First Nations and Tribal Councils, OSLP is primarily responsible for administering projects and programs for WPLP relating to community engagement, community readiness, education & training, business readiness, communications, capacity building, and certain aspects of stakeholder engagement.

Through a Service Agreement with WPLP, OSLP works with WPLP and Valard to assist the Participating First Nations in building capacity[4] and obtaining meaningful participation in the Transmission Project for members of their communities. The mandate to coordinate and work with each Participating First Nation on their local knowledge related to project execution is intended to mitigate execution risk and benefit all parties, as well as develop potential future employees to operate and maintain the transmission system. Opportunities for Indigenous participation are facilitated through delivery of job-specific training related to various aspects of project construction and logistics, as well as skills-development programs and cultural awareness training. OSLP also maintains a labour pool database and a registry of Indigenous businesses to assist WPLP in filling employment and sub-contracting opportunities for the Transmission Project. OSLP also provides regular monitoring and reporting with respect to Valard's Indigenous Participation Plan commitments in the EPC contract.

With respect to ongoing community engagement and project communications, OSLP manages the community issue tracker, coordinates community engagement meetings and logistics, liaises with Valard in regard to Valard's obligations for community engagement under the EPC contract, creates monthly newsletters, provides technical support for the project website, and coordinates communications through Community Liaisons to support engagement and communication activities consistent with WPLP's Indigenous Engagement Plan and Indigenous Communications Management Plan.[5]

OSLP also continues to monitor, and to the extent required facilitates, the development and implementation of backup supply arrangements on behalf of WPLP for all communities that will become grid-connected through the Transmission Project, and facilitates agreements and arrangements for the transfer of distribution system assets to HORCI for communities currently

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[4] Including for example working with local Indigenous businesses to obtain the qualifications necessary to provide sub-contracting support to the EPC contractor, and working with individual members of the community to obtain the education, training and qualifications necessary for employment on the project.

[5] See Exhibit B-1-2, Section B.7 for further discussion of these plans.

served by Independent Power Authorities ("IPAs").[6] While the underlying activities relating to backup supply arrangements and transferring distribution system assets from IPAs to HORCI are beyond the scope of this Application, WPLP is required as part of the Transmission Project to facilitate and report semi-annually to the OEB on the status of backup supply arrangements pursuant to the OEB's LTC Decision in EB-2018-0190, as well as the Settlement Agreement from EB-2021-0184, and WPLP continues to monitor the status of IPA distribution system transfers through regular reporting completed by OSLP. WPLP has coordinated to allow energization of WPLP's assets up to the 25 kV demarcation points between WPLP and HORCI in a manner that avoids impacts to the EPC contractor's schedule, while allowing for grid connection in accordance with timelines defined in Understanding and Conveyance Agreements once all IPA transfer conditions have been satisfied.[7] For 13 of the 16 connecting Indigenous communities, the backup supply arrangements leverage the generation assets and associated infrastructure currently providing the primary electricity supply within the communities to instead function in an emergency backup capacity during outages on or upstream of WPLP's transmission system. For the other three[8] communities, emergency backup supply will be provided for critical infrastructure locations, as applicable, instead of on a community-wide basis.[9]

Section B of Exhibit F-3-1 provides further detail related to the Services Agreement between WPLP and OSLP, and the annual costs incurred/forecasted pursuant to that agreement.

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[6] A copy of the most recent Indigenous Services Canada report on IPA and Backup Power was filed by WPLP as part of its Semi-Annual Report dated April 17, 2023, pursuant to EB-2018-0190.

[7] The Understanding and Conveyance Agreements identify timelines by which various activities must be completed prior to grid connection. These timelines are meant to allow sufficient time for HORCI to complete a number of complex and resource-intensive tasks following receipt of certain critical information from each IPA community, such as replacement of revenue meters and creation of customer accounts

[8] One of these three communities, Wawakapewin First Nation, continues to hold discussions with the Backup Power Working Group to determine whether an alternative, to critical asset backup only, is available.

[9] Details and status of backup power solutions for the 16 connecting Indigenous communities are provided in WPLP's semi-annual reports, filed pursuant to OEB's Decision and Order in EB-2018-0190. The most recent semi-annual report is dated April 17, 2023.

2. Wataynikaneyap Power PM Inc. ("WPPM")

Leveraging the knowledge, experience and expertise of Fortis Inc. and its subsidiaries in respect of all aspects of transmission system development and operation, WPPM is responsible for providing services related to project management, engineering, operations, finance, regulatory and various corporate functions (including health and safety, environmental compliance, HR, IT and procurement). Organizationally, WPPM provides these services in three functional areas:

- WPPM's Chief Operating Officer (COO) oversees all aspects of project and construction management, health and safety, environmental compliance, as well as engineering and operations.
- WPPM's VP Finance & Chief Financial Officer (CFO) oversees all aspects of finance/accounting, procurement, risk management and regulatory affairs.
- WPPM's VP Corporate Services and Indigenous Relations oversees all aspects of legal services, HR and IT. This position is also responsible for overseeing WPPM's participation in the various recruitment, training, engagement and communication activities that are coordinated by OSLP, in consideration of WPLP's overall direction to provide meaningful Indigenous participation in the Transmission Project, and in consideration of WPLP's Indigenous Engagement Plan and Indigenous Communications Management Plan.

Section B of Exhibit F-3-1 provides further details related to the Management Agreement between WPLP and WPPM, and the annual costs incurred/forecasted pursuant to that agreement. Employee compensation details for direct employees of WPPM are provided in Section A of Exhibit F-3-1.

3. Valard (EPC Contractor)

The terms of the EPC contract between WPLP and Valard broadly require Valard to undertake all engineering, procurement and construction activities in order to construct the Transmission Project on a turn-key basis. The EPC contract assigns the majority of the project execution risk to

Valard,[10] with the exception of certain pre-determined owner risk events and force majeure events that are typical in consideration of the project and EPC contracting strategy.

The EPC contract incorporates Indigenous participation commitments, including requirements to report on Indigenous participation and employment results, and to develop remediation and transition plans where results fall short of contractual commitments. OSLP works with Valard, Hatch and WPLP to verify Valard's reporting of Indigenous participation and employment results to the Participating First Nations, and to provide communication, community engagement and liaison support in respect of these activities.

The EPC contract also places direct responsibility on Valard to prepare and implement project-specific work plans, quality management plans and procedures, including requirements for engaging with communities to confirm work plans, inspections and testing, environmental and permitting requirements, document control, resource competency, equipment certification and quality control, and change management. The responsibility for construction management and quality management of all EPC activities rests with Valard.

4. Hatch (Owner's Engineer)

As described in Exhibit B-1-2, WPLP engaged Hatch to provide services in an OE capacity through a competitive procurement process in 2018. As is typical in large infrastructure projects constructed through an EPC process, the OE supplemented WPLP's own engineering and project management resources during the EPC tendering process and continues to provide project management and EPC oversight services during the detailed engineering, procurement and construction phases of the project. Hatch provides a variety of project and process management resources, technical subject matter experts, qualified field inspectors, and document control services to support WPLP's oversight of the EPC contractor, as well as to support change

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[10] Valard is the Construction Authority on the Project site with responsibility for all aspects of Health and Safety including the Health and Safety COVID-19 protocols/procedures.

management, cost management, performance and risk management and reporting processes, as described in Section B below.

5. Mott MacDonald (Independent Engineer)

WPLP negotiated project-specific financing with a consortium of five bank lenders, as well as Ontario, (collectively the "Lenders"), resulting in a Common Terms and Intercreditor Agreement ("CTIA") as described in Exhibit G-2-1. To support the Lenders' due diligence process prior to financial close, Mott MacDonald, was engaged by WPLP as the IE to undertake a technical review of the Transmission Project. During the construction phase, WPLP has continued its engagement with the IE to support CTIA requirements related to independent review and certification of advances, progress invoices, project completion and milestones, as well as monthly reporting to the Lenders on project status. This independent, third-party review of construction activities, change management, and invoice approval assists WPLP, and ultimately ratepayers, by considering value for the services performed relative to the objectives of the Project.

B. Contractor Coordination and Oversight

The EPC contract assigns most responsibilities and risks to Valard as the EPC contractor. WPLP's role as the Project owner is to provide coordination and oversight. WPLP also coordinates with the EPC contractor to obtain and provide certain owner-supplied permits pursuant to the EPC contract, as well as to review and support any contractor-supplied permits.

1. Contractor Coordination

On behalf of WPLP, OSLP works with the 24 Participating First Nations, as well as any Tribal Councils representing their member communities, to provide ongoing services related to community engagement, project communications, employment and training, and business readiness. Specifically, OSLP delivers targeted training programs and maintains a labour pool database and a registry of Indigenous businesses in the Participating First Nations. These services allow OSLP to maximize Indigenous employment and subcontracting opportunities related to the Transmission Project. As noted above, the mandate to coordinate and work with each Participating

First Nation on their local knowledge related to project execution is intended to mitigate execution risk and benefit all parties, as well as develop potential future employees to operate and maintain the transmission system.

The EPC contract includes an explicit allocation of responsibility for permits as between WPLP and Valard. While Valard is ultimately responsible for managing the requirements of all permits, once obtained, coordination with WPLP is required for permit applications and amendments. WPPM's land and environmental leads, supported by the OE, regularly interact with Valard in overseeing whether permits are being monitored and amended as required, and to verify whether permit applications submitted by Valard are reviewed and approved prior to submission.

In addition to the specific Indigenous participation and permitting coordination efforts described above, WPLP, Hatch and Valard hold a variety of regular meetings to coordinate on a range of technical and logistical aspects of the project.

2. Contractor Oversight

Sections 3 through 5 below provide details on procedures related to EPC contract oversight with respect to change management, cost and performance management, as well as project tracking and reporting.

Direct oversight of construction activity in the field is also provided on behalf of WPLP through daily inspections and monitoring conducted by field inspectors employed by Hatch and periodic inspections completed by WPPM. Given the size of the Project footprint, such monitoring and oversight of construction activity does not cover the entire Project. These efforts are focused on documenting compliance or concerns with respect to health and safety requirements, environmental protection requirements, and QA/QC provisions of the EPC contract. Each inspector submits concise daily summary reports, which document compliance with various contractual requirements, identify any areas of concern, and provide summaries of construction progress, including photos of key work activities and constructed assets. In addition to the daily reports, the field inspectors initiate queries that are raised with Valard for any specific concerns that are noted vis-à-vis quality, environmental or safety. The field inspectors also identify any progress or field mobilization/crew movement concerns; and help in evaluation of construction impacts the cost of which is the subject of commercial discussions with the EPC contractor. The inspectors take part in regular meetings with WPPM management to provide first hand feedback; and the frequency of these meetings could be increased as per requirements (e.g., critical winter construction seasons).

3. Change Management

WPLP has implemented a comprehensive process for managing EPC contract changes, which is overseen by WPPM and administered by Hatch in its role as OE. The change management process is designed to ensure that any requested changes have contractual merit and are appropriately communicated, documented and reviewed prior to the execution of a formal change order.

An information request process is used to communicate requests for clarification or additional information related to interpretation of EPC contract provisions. This process facilitates the review of information by the appropriate personnel from each of the parties. This process also assists in documenting and facilitating notifications regarding emerging issues. The information request process may provide the required clarification and help avoid the need for a contract change order.

WPLP and Hatch have implemented additional change management processes related to routing, since routing changes have the potential to significantly impact community engagement, permitting, schedule and cost. Requests to consider routing changes can be initiated either by WPLP or the EPC contractor, for a variety of reasons as discussed in Exhibit B-1-1. WPLP's change management process related to routing involves reviews of any proposed routing changes to ensure that the proposed changes are based on viability from multiple perspectives, including community and land-user approval, technical and constructability, as well as impacts on permitting, cost and schedule.

WPLP's change management processes are integrated with the cost and performance management processes described in Section 4 below and the project tracking and reporting processes described in Section 5 below.

4. Performance and Cost Management

Conformance to technical specifications included in the EPC contract during the engineering and procurement stages is aided by detailed design reviews from Hatch subject matter experts and WPPM technical staff, each acting on behalf of WPLP, as well as reviews of test reports, factory acceptance testing, and other approval or certification documents.

WPLP monitors the performance of the EPC contractor through processes and procedures administered by Hatch in its role as the OE, with oversight from WPPM. Many of the related processes and procedures are described in Sections 1 through 3 above.

Hatch also administers a cost management process on behalf of WPLP, which includes reviewing and validating progress invoices and supporting documentation from the EPC contractor and approving payment certificates. Mott MacDonald, in its role as the IE, also independently reviews and certifies advances and progress invoices. Hatch's cost management procedure for WPLP ensures that payments to the EPC contractor are commensurate with work performed in accordance with the Rules of Credit developed and agreed to by the EPC contractor, WPLP, Hatch and the IE. The Rules of Credit ensure progress payments to the EPC contractor tie to the activities in the field and ensure appropriate supporting information is provided to validate work progress. This procedure is also integrated with the change management process to enable tracking and reporting of costs related to change orders.

5. Project Tracking and Reporting

Valard is required to provide certain daily, weekly, monthly and annual reports to WPLP under the terms of the EPC contract. These reports provide insight on project progress, emerging issues, and conformance with various provisions of the EPC contract, including requirements related to health and safety, environmental protection, Indigenous participation, engineering and procurement progress, permitting, employment, and quality control. These reports support WPLP's general oversight of the EPC contract, as well as a variety of ongoing project communication and engagement activities.

Hatch also provides certain daily, weekly, monthly and quarterly reports to WPLP. Hatch's weekly, monthly and quarterly reports summarize content from Valard's reporting requirements, emerging issues and outstanding RFIs, and incorporate additional analysis related to progress vs. plan and key project risks. Daily reports submitted by Hatch's field inspectors provide a snapshot of construction activities each day, document conformance with EPC contract requirements, and identify any critical health, safety, environmental or quality control issues.

Valard, WPLP and Hatch also provide reporting and information to Mott MacDonald as required to support its monthly IE report to the Lenders.

C. Operations and Maintenance

From the time that WPLP secured all necessary pre-construction approvals and project financing in 2019, it has been focused on implementing a robust structure for project execution to support the successful construction of the Transmission Project, as described throughout this Schedule. Almost immediately after working with the OE and EPC contractor to initiate right of way clearing and initial construction activities in late 2019 and early 2020, COVID-19 was declared a pandemic, and WPLP's efforts have since then included dealing with operational, financial and schedule impacts associated with the pandemic. In EB-2021-0134 and EB-2022-0149, WPLP described its interim O&M strategy for transitioning from a primary focus on construction of its transmission system to an increasing focus on operations and maintenance of that system as it comes into service. WPLP has implemented the strategy described in previous applications by successfully recruiting for a number of key internal positions, and competitively procuring third-party services in a manner that incorporates Indigenous Participation objectives. WPLP expects that its O&M strategy will meet immediate requirements, while continuing to evolve as additional assets are placed in service and as maintenance requirements associated with those assets increase over time. The primary components and objectives of WPLP's O&M Strategy are as follows:

1. Inspection, Maintenance and Emergency Response

WPLP's O&M strategy includes consideration for the scalability of resources from several perspectives. First, as assets come into service at various points during 2022, 2023 and 2024, the number of assets to be operated, inspected and maintained will increase on a monthly basis. Second, WPLP expects that inspection and maintenance cycles will be evaluated and adjusted in consideration of actual inspection results, system performance and costs, which may lead to changes in its inspection and maintenance programs.

Third, WPLP's transmission system, like any other transmission system, will be exposed to severe weather events and, due to its remote location and geography, forest fires are also a concern. The frequency, location and intensity of such events cannot be accurately predicted in advance, nor can the extent of any related damage that may occur to WPLP's transmission system. While WPLP's design parameters are intended to allow its system to withstand reasonably foreseeable severe weather events, and the use of lattice steel towers for most line segments will mitigate the risk of fire damage (as compared to wood poles), emergency response efforts will likely require mobilization of third-party resources, particularly as an increasing numbers of geographically dispersed line segments and substations are placed in service during 2022, 2023 and 2024.

WPLP's O&M strategy therefore includes an agreement with a primary third-party service provider for inspection, maintenance and emergency response ("IMER") activities, in order to be able to quickly and efficiently scale up third-party resources to address increasing requirements for regular O&M activities and uncertain requirements for emergency response.

The objectives of the IMER procurement process completed in 2022 were to meet immediate requirements for safety, reliability, technical expertise and regulatory compliance, as well as to maximize opportunities for Indigenous Participation and capacity building. In this regard, WPLP with the support of its OE, developed a two-stage competitive procurement process to select one or more service providers with inspection, maintenance and emergency response capabilities. A Request for Expressions of Interest was issued on March 25, 2022, followed by the Request for Proposals on May 20, 2022. Potential service providers filed their proposals with WPLP on June

17, 2022. Through this process, WPLP selected PowerTel Utilities Contractors Limited ("PowerTel") as the service provider that could offer the required resources and expertise, with demonstrated commitments to Indigenous Participation and health and safety to provide the IMER services needed for the Transmission Project. The IMER services include planned inspections of transmission line and substation assets, substation equipment testing and maintenance, and response to power outages and other emergencies. Under the general direction of WPLP, PowerTel will be expected to carry out the relevant IMER services in a manner that supports the Indigenous ownership and control of the transmission system. Specifically, the IMER service agreement provides for apprenticeship opportunities for members of Participating First Nations, who will work for PowerTel on the IMER activities as well as other projects unrelated to WPLP. This arrangement will allow apprentices to gain the broad experience required to complete their apprenticeships. Developing a talent pool of local Indigenous tradespeople will allow WPLP to consider self-performing certain IMER activities in the future, while continuing to rely on third-parties for other activities and to scale up resources as required for emergency response.

The IMER service agreement provides for a baseline of fixed price inspection and maintenance activity until December 31, 2026, including quarterly substation inspections, annual aerial inspections of all in-service transmission lines, annual ground inspections of a portion of in-service transmission lines and major equipment maintenance on a multi-year cycle. Emergency response activities and reactive work (e.g. non-emergency work required to identify concerns noted during scheduled inspections) are undertaken on a time and material basis as required.

WPLP will also consider the feasibility of mutual assistance agreements with nearby utilities and service agreements with other service providers to provide additional resources if required during emergencies.

Further to the IMER procurement process, to satisfy the immediate need for 24/7 control room operations, WPLP executed an agreement for Hydro One Networks Inc. ("Hydro One") to provide control room services until such time that WPLP develops its own control room. The parties have also finalized the required scope for the integration of WPLP's SCADA network to the Hydro

One's control room and have executed a related service agreement. This arrangement allows for the initial integration of WPLP's SCADA network to leverage existing communication channels and processes between Hydro One and IESO control rooms, reducing execution risk during commissioning and IESO registration prior to energization.

In addition, to support the reliable operation of transmission assets that will soon be put into service, WPLP has been focused on the procurement of spares and developing its facilities and fleet strategies. These aspects have been impacted by evolving supply chain challenges. Following the selection of PowerTel as WPLP's IMER service provider, WPLP is finalizing its initial facilities and fleet strategies to account for equipment those services that can be provided by PowerTel and additional investments that are required to support both planned O&M activity as well as emergency response scenarios.

2. Focus on Indigenous Participation

Identification of Indigenous businesses in the 24 Participating First Nations with capacity to support construction of the Transmission Project has led to a number of Indigenous subcontractors and joint ventures providing services to the project through subcontracts with Valard. OSLP and Valard on behalf of WPLP have also delivered a variety of training programs to members of the Participating First Nations during the development and construction phases of the Transmission Project, leading to direct and indirect employment opportunities during the construction phase.

WPLP's commitment to Indigenous participation extends beyond the construction phase of the Transmission Project to all aspects of WPLP's ownership and operation of the transmission system. WPLP's O&M strategy includes a focus on opportunities to extend training programs that have been delayed by COVID-19.[11] This approach is providing opportunities for members of the Participating First Nations to gain relevant experience in operations and maintenance activities to supplement experience gained during the construction phase of the project. Balancing internal and

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[11] Through OSLP, WPLP has been able to get specific funding extended, thereby allowing certain training to continue throughout 2022 and into 2023 to ensure training that was delayed as a result of COVID-19 can be implemented. As of March 20, 2023, 383 Indigenous individuals have been trained since 2017 in 50 training programs. An additional 9 training programs are planned for 2023.

contracted O&M resources will provide opportunities for job shadowing and longer-term employment for members of the Participating First Nations, as described in Sections 4 and 5 below.

3. Evaluating Emerging Technologies and Work Methods

WPLP is in a position where it will need to be scaling up operations and maintenance activities on its transmission system, but without having pre-existing programs, procedures or work methods related to these activities. While this presents a challenge in the context of developing a comprehensive O&M Strategy supported by appropriate processes and procedures, WPLP recognizes that it also presents a unique opportunity to consider emerging and innovative technologies and work methods, and to tailor the overall O&M strategy to WPLP's circumstances.

As an example, traditional inspection techniques (e.g. drive-by or ground patrols) or typical inspection frequencies may result in safety risks, environmental impacts, or cost impacts that vary significantly for WPLP relative to other Ontario transmitters when considering WPLP's remote location, geography, access logistics and seasonal constraints. This may lead WPLP to consider alternative technologies and work methods, in engagement with Indigenous Peoples and communities, such as integrating infrared scanning and high-resolution imagery capture into devices linked to asset management system during planned inspections, deployment of additional online and remote monitoring equipment, and/or adjustments to the frequency and intensity of inspections.

4. Efficient Transition from Construction Resources

As construction of the Transmission Project comes to an end in 2024, WPLP is pursuing opportunities where construction access, facilities and other resources can be leveraged to support the ramp up of O&M activities. Examples include delivery of spare material to Valard's primary laydown yard to take advantage of labour, equipment and physical space that could accommodate delivery, receipt and offloading of WPLP's spare materials in addition to managing materials staged for construction.

WPLP's O&M strategy also considers opportunities to leverage the ongoing use of construction access for permanent operational access, and use of labour and contractor resources that would otherwise be ramping down efforts on construction. Any agreements resulting from WPLP's continued use of these resources would be expected to include requirements for Indigenous participation, which would provide opportunities for ongoing training and skills development related to O&M requirements for members of the Participating First Nations and long-term opportunities for Indigenous businesses.

5. Recruiting Internal Resources

As assets come into service during the construction period, WPLP is balancing the use of local operational resources (including direct employment and contracts with local Indigenous businesses) and other third-party service providers to perform cyclical inspections, operating activities and maintenance tasks. In the longer term, WPLP will work towards scaling up local operational resources to perform additional O&M tasks, as well as to continue coordinating any other third-party service providers that may be contracted to support certain corrective maintenance activities, large-scale emergency response efforts, or other spikes in overall work activity. WPLP's O&M strategy contemplates recruitment of the local operational staff required to perform these functions over the longer term. The pace at which WPLP will increase its operational staff will depend on the pace at which local Indigenous candidates progress through apprenticeship programs with third-party service providers. Identification of local candidates will be supported by ensuring that a labour pool database remains available to maximize employment opportunities for members of the Participating First Nations.

WPPM has also been actively recruiting additional personnel in the areas of operations, engineering and asset management, who are focused on implementing, supporting and refining its O&M strategy. Specifically, in 2022, WPLP hired an Electrical EIT, a Manager of Operations and an Operations Coordinator (Stations) to support the ramp up of its O&M activities. In 2023, WPLP plans to hire three additional full-time engineering and operations positions with a focus on coordination and oversight of IMER activities, coordination of protection, control and communication system maintenance and troubleshooting, as well as preparing for the ramp up of a large-scale vegetation management program. These additional positions will also support a range of functions associated with the Interim O&M Strategy, including O&M procurement, commissioning, asset management and system/process development.

Exhibit B, Tab 1, Schedule 5

Project Costs

PROJECT COSTS

A. Overview

This schedule provides detailed Transmission Project cost information, as well as information on other infrastructure capital costs and operating costs, and explanations for variances relative to the costs previously approved by the OEB. The presentation of Transmission Project cost information includes both the costs WPLP has incurred or expects to incur under its EPC contract and those capital costs it has incurred or expects to incur outside of that contract in relation to the Transmission Project. In addition, this schedule describes how overhead costs are assigned to or allocated between capital and OM&A for each of the Line to Pickle Lake and Remote Connection Line portions of the Transmission System over the construction period.

WPLP notes that, as the current application is for a single test year, for the expected last year of Project construction, all of the costs set out in this schedule will be relevant for purposes of the proposed 2024 revenue requirement. Also relevant to WPLP's proposed revenue requirement in this Application are its 2024 OM&A costs (which are detailed in Exhibit F), and its overhead costs that are either recorded in CWIP and subsequently capitalized as assets are placed in service or allocated to OM&A as described in **Appendix 'A'**. The exhibits that present the capital and OM&A costs specifically underlying the proposed revenue requirement for 2024 are cross-referenced where appropriate.

WPLP further notes that, except where otherwise indicated, the impacts of the COVID-19 pandemic and amounts that continue to be the subject of commercial discussions between WPLP and the EPC contractor have not been included in these capital cost forecasts. Rather, pursuant to the Settlement Agreements in EB-2021-0134 and EB-2022-0149, WPLP:

- has recorded its audited 2020 COVID costs in the COVID Construction Costs Deferral Account (CCCDA), and is recovering those costs as an OM&A expense over the four-year disposition period (2022-2025) approved in EB-2021-0134; and

- has been recording, in the 2021-2023 COVID Construction Costs Deferral Account (2021-2023 CCCDA), the incremental year-end COVID costs from 2021 to 2023, with the prudence and approach to disposition of such amounts to be determined at the time of disposition in a future rate application once the COVID cost information for these years is known.

In the current Application, as described in greater detail in Exhibit H, WPLP is proposing:

- that WPLP be permitted to transfer the 2021-2023 CCCDA audited (to December 31, 2022) and unaudited (from January 1, 2023 to December 31, 2023) 2023 year-end forecast balance, together with applicable AFUDC, to CWIP Account 2055 on December 31, 2023;
    - in respect of assets that are in service as of the date of this application or that are expected to come into service during the remainder of 2023, that WPLP be permitted to add to its rate base, effective January 1, 2024, the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023;
    - in respect of assets that are expected to come into service during 2024, that WPLP be permitted to add to its rate base, effective from the dates such assets come into service during 2024, the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023;
- to continue the 2021-2023 CCCDA subject to modification by specifying that any amounts recorded therein will be treated as capital and by expanding the scope of the account by one year to allow for the tracking of any COVID-related capital costs that WPLP may recognize as relating to 2020 (as well as to 2021-2023) upon conclusion of the commercial discussions that are ongoing with its EPC contractor;

- to modify CWIP Account 2055 by adding a new sub-account to track certain COVID-related capital costs that relate to the period from 2020 onward, as more particularly set out in Exhibit H-1-1; and

- to establish a new EPC COVID-Related Costs Deferral Account to record costs incurred and to be incurred in respect of anticipated claims under its EPC Contract that relate to 2024 or later and which continue to be the subject of commercial discussions between WPLP and its contractor, together with AFUDC applicable to such amounts from the dates they are incurred.

These aspects are described in greater detail in Exhibit H.

B. Context for WPLP's Cost Forecasts

In Part C, below, WPLP provides detailed descriptions of its forecast capital costs, including capitalization of overheads. For details on WPLP's proposed rate base and in-service additions, please refer to Exhibit C. For details on WPLP's operating costs during the 2024 test year, please refer to Exhibit F. As context for each of these aspects of the application, particularly for Part C of this schedule, it is helpful to understand (i) the difference in how costs have been presented in the current application and its prior application as compared to the presentation of costs in WPLP's initial rate application, (ii) the various sources or categories of costs that feed into the cost forecasts, and (iii) the currency of the information upon which this application is based, as follows.

1. Difference in Presentation of Costs Relative to Initial Rate Application

There is an important difference in the presentation of cost information in the current application as compared to the presentation of cost information in WPLP's 2022 revenue requirement application (EB-2021-0134). As the 2022 revenue requirement application was WPLP's first such application, WPLP was required to provide details of its updated Transmission Project costs and comparisons of those updated Transmission Project costs relative to the cost estimates that had been presented in its Leave to Construct (LTC) application (EB-2018-0190).

WPLP explained in EB-2021-0134 that its forecast of Transmission Project capital costs was not only more current, but also more complete, more rigorous and more accurate than the estimate that it was able to provide during the LTC proceeding. WPLP noted that its ability to produce a better cost forecast for purposes of the initial rate application was a result of the normal project development process, during which further development activities, such as completion of geotechnical surveys and competitive procurement processes (including for the EPC contract), provided increased certainty regarding key project cost drivers, such as ground conditions, equipment costs and construction costs. Through that process, as the various cost components became more certain, the proportion of contingency costs included in the project cost forecast was reduced in the initial rate application as compared to the LTC cost estimate.

In addition, whereas the LTC application only considered Transmission Project costs, the initial revenue requirement application included forecasts of additional capital costs outside of the Transmission Project (i.e. general plant) and OM&A costs, including overheads which are allocated between capital and OM&A. Consequently, the presentation of cost information in EB-2021-0134 was complicated by the need to describe the fundamentally different bases upon which the LTC cost estimate and the 2022 cost forecast were determined, and to explain the resulting variances relative to the estimates that the OEB had previously seen in the LTC proceeding.

Starting in the 2023 revenue requirement application and continuing in the current application, the presentation of cost information is considerably more straightforward. While there are still some complexities as a result of the Transmission Project continuing to be under construction and WPLP continuing to transition from its organizational focus on development and construction to its longer-term focus on operations, the updated cost information in the 2023 and current applications have been developed on the same basis as, and are generally comparable to, the cost information underlying the 2022 revenue requirement, as presented in EB-2021-0134. It is for this reason that the OEB agreed with WPLP in EB-2018-0190 that any variance analysis provided as construction progresses beyond the initial rate application would consider actual or forecast costs compared to those presented in the initial rate application, rather than compared to the original cost estimates that had been presented in the LTC application.[1]

2. Cost Categories Underlying 2024 Forecast

WPLP's cost forecasts for 2024 are based on the following sources or cost categories:

a) **EPC Contract Costs:** expected engineering, procurement and construction costs based on the EPC contract;

b) **Non-EPC Capital Costs:** estimated capital costs of items that are accounted for outside of the EPC contract, but which are nevertheless planned and required by WPLP;

c) **Overhead Costs:** labour, consulting and administrative costs to December 31, 2024**,** determined by WPLP through a bottom-up forecast, which has been reviewed by Hatch in its capacity as Owner's Engineer (OE) and which identifies costs that are either capitalized or allocated to OM&A using the methodology described in **Appendix 'A'**;

d) **Direct O&M Costs:** operating and maintenance costs, determined by WPLP through a bottom-up forecast and informed by the executed IMER Agreement, further discussed in Exhibit B-1-4, directly related to the regular operation, inspection, maintenance and emergency response requirements associated with operating the transmission assets as they come into service; and

e) **Contingency Costs:** a quantitative risk-based contingency analysis performed by the OE.

The relationship between the cost categories listed above, the Capital cost forecasts presented in Section C of this schedule and the OM&A cost forecasts presented in Exhibit F, are summarized in Table 1, below.

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[1] OEB, Decision and Order, EB-2018-0190, April 1, 2019 (Revised April 29, 2019), pp. 12-13.

Table 1 – Sources of Cost Forecast Information

Cost Category	**Capital Cost Forecast (Section C Below)**	**OM&A Cost Forecast (Exhibit F)**
EPC Contract Costs	100%	-
Non-EPC Capital Costs	100%	-
Overhead Costs	Allocated per Appendix ‘A’	Allocated per Appendix ‘A’
Direct O&M Costs	-	100%
Contingency Costs	100%	-

3. Currency of Information

The updated capital cost forecast in the current Application includes audited actual costs to December 31, 2022 as well as WPLP’s updated forecasts for 2023-2024 capital costs, as at May 30, 2023.[2] This is aligned with the currency of the construction schedule underlying the current Application, which was issued by WPLP’s EPC contractor on May 30, 2023 and reflects the schedule as at that date.

C. Capital Costs

This section presents WPLP’s forecast capital expenditures by year, as well as by expenditure category, including analysis of variances from capital costs approved by the OEB in WPLP’s 2023 revenue requirement application to WPLP’s updated capital cost forecast as at May 30, 2023.

1. Capital Expenditure Forecast by Year

WPLP’s capital expenditures by year, excluding AFUDC, are summarized in Table 2, below.

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[2] WPLP recognizes that inflation rates have been elevated since early 2022. However, given that the EPC Contract was for a fixed price, the majority of its capital costs are not subject to the changes in inflation. To the extent inflation impacts the non-EPC costs, it has been reflected in the forecasted amounts.

Table 2 – Capital Expenditures by Year

Year	**Capital Expenditures ($000's)**		**% of Cumulative**
	Annual	**Cumulative**	
Pre-2019 Actual	[redacted]	[redacted]	[redacted]
2019 Actual	[redacted]	[redacted]	[redacted]
2020 Actual	[redacted]	[redacted]	[redacted]
2021 Actual	[redacted]	[redacted]	[redacted]
2022 Actual	[redacted]	[redacted]	[redacted]
2023 Forecast	[redacted]	[redacted]	[redacted]
2024 Forecast	[redacted]	[redacted]	[redacted]

The timing of capital expenditures forecasted in Table 2 above is largely based on construction activity by WPLP's EPC contractor, based on the May 30, 2023 updated construction schedule that is discussed in detail in Exhibit B-1-3. These expenditures are recorded as CWIP until the related assets become used or useful. WPLP's forecasted in-service additions are presented in Exhibit C-2-1.

2. Capital Expenditure Forecast by Category

WPLP's current forecast of its Transmission Project capital costs (excluding COVID costs) is approximately $1.82 billion inclusive of interest, or approximately $1.91[5] billion inclusive of other development, infrastructure costs (not forming part of the Transmission Project) and COVID costs. WPLP's equivalent forecast as presented in the 2023 rate application, was approximately $1.81 billion, or approximately $1.82 billion inclusive of other development and infrastructure costs. These amounts, both for the current forecast and the forecast presented in the 2023 application, are

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[3] See Appendix to Exhibit C-2-l, Table A-1 for calculation of $1,837 million of project costs. (Total Capital costs of $1,906 million less Capitalized Interest $69 million)

[4] This cost does not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account or in the 2021-2023 CCCDA (as proposed to be amended) upon the conclusion of the commercial discussions between WPLP and its EPC contractor.

[5] This cost does not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account or in the 2021-2023 CCCDA (as proposed to be amended) upon the conclusion of the commercial discussions between WPLP and its EPC contractor.

set out in Table 3, below, using cost categories consistent with those presented in EB-2021-0134. The table is followed by detailed descriptions for each individual cost category of the capital expenditure forecast.

Consistent with the structure of Table 3, the descriptions of the individual cost categories are grouped into (i) EPC-related capital costs for the Transmission Project, (ii) non-EPC capital costs for the Transmission Project, and (iii) capital costs for other infrastructure not forming part of the Transmission Project. As indicated in the table, WPLP's total capital cost forecast is approximately 5% ($84 million) higher than the Transmission Project cost estimate presented in the 2023 application. This difference is driven by inclusion of COVID costs of $74.6 million, a reduction in EPC and Non-EPC Capital costs of $11.6 million[6], and additional capitalized interest costs based on December 31, 2022 construction interest rates of $21.2 million.

Table 3 – Capital Cost Forecast and Variance Summary

(Costs in $000's)	**Updated Forecast[7]**	**Forecast with COVID[8]**	**2023 Rate Application**	**Variance**	
				$	**%**
EPC Costs					
Transmission Line Facilities - Line to Pickle Lake	214,987	[redacted]	214,987	0	0%
Transmission Line Facilities - Remote Connection Lines	911,224	[redacted]	906,370	4,854	1%
Station Facilities - Line to Pickle Lake	38,472	[redacted]	38,018	454	1%
Station Facilities - Remote Connection Lines	304,426	[redacted]	298,094	6,332	2%
Non-EPC Capital Costs		[redacted]			
EPC Excluded (e.g. Insurance, LIDAR, Stumpage)	10,012	[redacted]	13,097	-3,085	-24%
Engineering, Design, Project/Construction Management & Procurement	108,690	[redacted]	112,036	-3,346	-3%

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[6] Includes both recognized and forecasted non-EPC savings. WPLP continues to look for ways to reduce non-EPC costs, through cost management processes and a bottom-up budgeting approach.

[7] As at May 2023, with incremental COVID costs reported as separate cost category.

[8] Column discloses COVID costs within existing cost categories within table, rather than as its own line item as indicated in the first column.

Environmental Assessments, Routing, Permitting, Regulatory & Legal	27,287	[redacted]	28,291	-1,004	-4%
Land Rights	11,902	[redacted]	13,167	-1,265	-10%
Engagement, Stakeholder Consultation, Participation and Training	44,541	[redacted]	47,400	-2,859	-6%
Contingency	81,882	[redacted]	93,522	-11,640	-12%
Costs Included in EB-2018-0190, Pre-AFUDC	***1,753,422***	[redacted]	***1,764,982***	***-11,560***	***-1%***
Capitalized Interest	68,781	[redacted]	47,601	21,180	44%
Total Costs Included in EB-2018-0190	***1,822,204***	[redacted]	***1,812,583***	***9,621***	***1%***
Other Infrastructure	9,245	[redacted]	9,450	-205	-2%
COVID-19 Costs	74,570	[redacted]	-	74,570	-
Total Capital Costs[9]	**1,906,019**	[redacted]	**1,822,033**	**83,986**	**5%**

The table above provides variances between the updated forecast with COVID-19 costs as a separate cost category and the 2023 rate application given that the table in the 2023 rate application did not contemplate COVID-19 costs in the Capital Cost Forecast.

(a) Transmission Project Capital Costs (EPC)

WPLP forecasts capital costs relating to the EPC contract totaling approximately $1,469 million, inclusive of all transmission lines and stations for the Line to Pickle Lake and Remote Connection Lines portions of the project. The EPC-related costs in relation to the planned transmission line facilities and station facilities are further described as follows, along with discussion of how the EPC contract costs in the current capital cost forecast compare to the EPC contract costs that were included in the capital cost forecast in the initial rate application, as amended.

(i) Transmission Line Facilities

WPLP's EPC contract cost for the 230 kV transmission line facilities associated with the Line to Pickle Lake is approximately $215 million and the EPC contract cost for the 115 kV, 44 kV and

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[9] These costs do not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account or in the 2021-2023 CCCDA (as proposed to be amended) upon the conclusion of the commercial discussions between WPLP and its EPC contractor.

25 kV transmission lines associated with the Remote Connection Lines portion of the project is approximately $911 million. When compared to the equivalent EPC contract costs presented in the 2023 rate application as amended, the current amounts are $4.9 million higher. This difference is attributable to executed change orders, other costs related to forest fire and MNRF fire prevention order impacts, as well as route changes, that are the subject of commercial discussions with the EPC contractor for the remainder of construction period.[10]

(ii) Station Facilities

WPLP's forecast costs under the EPC contract cost for the two station facilities associated with the Line to Pickle Lake is approximately $38 million and for the 20 station facilities associated with the Remote Connection Lines portion of the project is approximately $304 million. When compared to the equivalent EPC contract costs presented in the initial rate application, as amended, the current amounts are $6.3 million higher. This difference is attributable to executed change orders, other costs related to forest fire and MNRF fire prevention order impacts, as well as route changes, that are the subject of commercial discussions with the EPC contractor for the remainder of construction period.[11]

(b) Transmission Project Capital Costs (non-EPC)

WPLP forecasts capital costs for the Transmission Project outside of the EPC contract totaling approximately $355 million. These non-EPC capital costs for the Transmission Project consist of capital costs that are necessary to develop, construct and put the Transmission Project into service and that were contemplated in the LTC proceeding, but which have not and will not be incurred through the EPC contract with Valard. When compared to the equivalent non-EPC Transmission Project capital costs presented in the 2023 rate application, the current amounts are $0.3 million higher. This difference is attributable to a reduction in non-EPC costs of $11.2 million, $11.6

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[10] Additional information on the variance is provided in Exhibit C-2-1.

[11] Additional information on the variance is provided in Exhibit C-2-1.

million lower from use of contingency, and increased capitalized interest of $23.1 million due to rising interest rates in 2023.

WPLP undertook a three-step approach to developing its forecast of the non-EPC capital costs for the Transmission Project:

- First, WPLP identified all of the non-EPC costs it has incurred or expects to incur over the project period that are clearly and directly related to the Transmission Project and are therefore clearly capital in nature. These include all costs incurred during the development phase of the Transmission Project, as well as costs for the Owner's Engineer and professional services support during the construction phase of the Transmission Project. The total capital costs identified through this step total approximately $121.7 million.

- Second, WPLP added into the forecast (a) its updated forecast for contingency (excluding EPC expected or executed change orders recognized in section 2(a) above), (b) its updated forecast for capitalized interest, and (c) certain discrete capital costs for aspects previously included as part of the EPC cost estimate but which were not ultimately included within the scope of the EPC services. These include costs, described in greater detail below, for HONI Interconnection, LiDAR services, stumpage fees and insurance. Office capital costs to December 31, 2024 are also included in this category. The capital costs identified through this step are approximately $81.9 million for contingency, $70.7 million for capitalized interest and $10 million for aspects previously included in the EPC cost estimate, for a total of approximately $162.5 million.

- Third, WPLP prepared a bottom-up budget forecast for its internal and operating costs, including employee compensation and other labour costs, costs for professional services and other third-party contracts, as well as general administrative or overhead costs. While in an operating utility these types of costs would typically be expensed unless specifically allocated to capital projects, such an approach is not appropriate for WPLP as it transitions from a project development and construction focused utility into an operating utility over a period of several years. Using the methodology described in **Appendix 'A'**, WPLP allocated these amounts between capital and OM&A based on the extent to which the Transmission System will be in service at different points during the construction period. The capital costs identified through this step total approximately $71 million.

WPLP has included all of the costs identified through the first and second steps, which are clearly capital in nature, in its forecast of non-EPC capital costs. However, for the costs identified through the third step, being the bottom-up forecast overhead costs, WPLP carried out an analysis of when those costs are expected to be incurred relative to when different segments of the Transmission System are expected to be put into service. WPLP then attributed the amounts from step three to capital or OM&A based on their timing and the corresponding portion of the Transmission System that will be in-service. Through this methodology, which is described in greater detail in **Appendix 'A'** and is consistent with the methodology applied in the initial transmission rate application, WPLP has effectively applied a declining capitalization rate to its overhead costs, commensurate with the extent to which the company is oriented toward Transmission Project execution vs utility operations, as it transitions from being a non-operating utility entirely focused on putting its system into service to a fully operating utility with a new system that requires minimal capital investment.

(i) EPC Excluded Costs

WPLP's forecast for this cost category includes approximately $10 million of costs that were previously accounted for as part of the EPC cost category in the LTC cost estimate. The costs are comprised of insurance costs, stumpage fees, LiDAR services costs and HONI interconnection costs. This category also includes approximately $0.83 million in office capital costs during the construction period.

Insurance costs related to the EPC contract were not budgeted as a distinct line item in the LTC cost estimate but were instead factored into the per-kilometer cost estimates for transmission line facilities and the base substation cost estimates described earlier in this schedule. Costs related to a variety of specific insurance and security requirements for the EPC contractor are included in the

EPC-related cost forecasts. However, in order to ensure an appropriate level of overall insurance coverage, WPLP determined that it could leverage the purchasing power of Fortis Inc. to obtain certain project level insurance more cost effectively outside of the EPC contract, without a material impact on allocation of risk. WPLP has therefore included a forecast for its own project-specific insurance costs of $6 million (compared to $18 million forecasted in the EPC cost category) as part of its forecast for EPC Excluded costs.

A portion of estimated stumpage fees related to the clearing of forest resources outside of Sustainable Forest Licence (SFL) areas was removed from the EPC contract since there was no framework for determining these costs at the time of EPC contract negotiations. WPLP received certain exemptions from the *Crown Forest Sustainability Act* on May 9, 2019, and subsequently negotiated lower costs for stumpage fees outside of SFL areas. Approximately $0.7 million in stumpage fees are therefore included in this cost category. For clarity, the EPC contractor retained the responsibility for dealing with SFL holders and paying the required stumpage fees within SFL areas. In addition, approximately $1.3 million for LiDAR surveys was transferred from the EPC cost category to the EPC Excluded cost category. Pre-EPC LiDAR activities were undertaken directly by WPLP in order to meet timing requirements for certain activities while the EPC tendering process and contract negotiations were still underway. This decision allowed WPLP to provide a certain amount of LiDAR data to all proponents during the EPC tendering process, allowing EPC proponents to de-risk their proposals. WPLP also made the decision to undertake post-construction LiDAR surveys internally so that it could ensure optimal timing and scope in relation to completion of EPC construction activities, WPLP's ongoing data requirements, and narrow windows of favourable conditions for conducting LiDAR surveys in the project area.

While the scope of the EPC contract includes the design, procurement and construction of equipment related to interconnections with both HONI and HORCI, WPLP has included in its non-EPC capital expenditure forecast approximately $0.95 million, separate from the general contingency amount discussed below, to cover undefined costs relating to its interconnections that are not included in the EPC contract scope.

(ii) Engineering, Design, Project/Construction Management & Procurement

WPLP’s updated forecast for capital costs relating to engineering, design, project/construction management and procurement is approximately $108 million.

This category of costs includes approximately $58 million in design, engineering and procurement costs related to advancing the conceptual design and engineering during the development phase of the Transmission Project, preparing detailed specifications and design requirements during preparation of the EPC tender package, engineering effort during EPC bid evaluation, and ongoing engineering oversight of the EPC contractor by WPLP’s OE. WPLP’s progressive design and engineering efforts demonstrated the viability of the Transmission Project, informed Long Term Energy Plans and IESO Regional Plans, met IESO-prescribed requirements for scope, allowed WPLP to obtain leave to construct the project, and ultimately determined the requirements for the EPC stage of the project. WPLP retained Hatch as its OE through a competitive selection process in 2018, as described in Exhibit B-1-2. This process included comparisons of hourly rates to ensure that any services provided on a time and materials basis would reflect market value. The services provided by Hatch, both during the EPC tendering process and during construction, reduced EPC cost uncertainty, minimized change orders during the construction phase of the project, assured quality and safety in all EPC activity, and assisted in maintaining overall project schedule.

The balance of approximately $50 million relates to project management activities that include accounting and finance costs, health and safety costs, executive/board oversight, oversight and support related to community engagement, communications and land access activities, as well as administrative costs related to office space, HR and IT. These costs allowed WPLP to secure overall project funding and financing, meet financial reporting requirements, develop and maintain project budgets, develop and implement health and safety processes and procedures, provide an appropriate level of oversight to engagement, communication and land access activities critical to the success of the project and to provide corporate financial, HR and IT support to all aspects of the project. Cost increases in this category are a result of the extended construction period due to delays of assets going in-service.

(iii) Environmental Assessments, Routing, Permitting, Regulatory & Legal

WPLP's current forecast for capital costs relating to environmental assessments, routing, permitting, regulatory and legal is approximately $27.3 million.

This category includes approximately $17.6 million in costs directly related to the legislated EA process and meeting all environmental commitments outlined in the Phase 1 EA report and Phase 2 Environmental Study Report (ESR). These costs were incurred to secure necessary approvals under provincial and federal environmental legislation for the Transmission Project to be constructed.

The balance of approximately $9.7 million relates to costs of permitting and regulatory requirements. This includes applying for and meeting the requirements of legislated permits or exemptions required to construct the Transmission Project. These costs also include the cost of all applications that have been filed or are planned to be filed with the OEB until the end of the construction period, as well as the costs of meeting any reporting requirements during that time.

Additionally, as described in Exhibit A-2-1, WPLP intends to file single test year revenue requirement applications for 2024 and 2025. Since the regulatory costs related to these applications will be in respect of single-test year applications, there is no need to amortize the costs over a multi-year incentive rate setting term. WPLP has therefore included the total forecast cost of filing these two applications in its total cost estimates to December 31, 2024 and has allocated these costs between capital and OM&A expenses using the same methodology for other overhead costs as described in **Appendix 'A'**.

WPLP's forecast for this cost category is approximately $1 million (3%) lower than the equivalent forecast as provided in the 2023 rate application.

(iv) Land Rights

WPLP’s updated forecast for capital costs relating to land rights is approximately $11.9 million. This includes all costs related to land options, easements, land sharing protocols, and land rentals required in relation to the construction and ongoing operation of the Transmission Project, as well as all labour costs, legal fees and related expenses for obtaining the required land rights. This category includes costs for both non-Aboriginal land rights and consultations, as well as costs in relation to Aboriginal land rights.

The current forecast is approximately $1.2 million (9%) lower than the equivalent estimate for this category as provided in the 2023 rate application. This difference is attributable to delays in incurring certain land costs due to changes in the construction schedule. As described in Exhibit B-1-2, WPLP has made significant progress in securing the various land rights and land permits required for the Transmission Project and it remains on track to secure any outstanding land rights and permits ahead of critical construction milestones.

(v) Engagement, Stakeholder Consultation, Participation and Training

WPLP’s updated forecast for capital costs relating to Indigenous and Métis engagement, stakeholder consultation, and Indigenous participation and training is approximately $44.7 million. These are costs related to Indigenous and Métis engagement during the EA process, WPLP’s comprehensive Indigenous Engagement Plan and Indigenous Communications Management Plan (which are summarized in Exhibit B-1-2), meaningful Indigenous economic participation in all aspects of the Transmission Project, consultations with stakeholders (such as municipalities and potentially affected landowners), and overall project communications activities. These activities will help ensure that the Transmission Project is designed, permitted, constructed and operated in a manner that respects the Aboriginal and Treaty, and Inherent rights of the Anishinabe and Anishinninuwug, and that appropriately considers input from various other stakeholders.

The updated forecast is approximately $2.7 million (6%) lower than the equivalent estimate for this category as provided in the 2023 rate application. This difference is attributable to realized savings in 2022 and expected future construction savings.

(vi) Contingency and EPC Change Orders

WPLP performs a contingency analysis on a semi-annual basis taking into consideration construction progress to date, the updated construction risk profile and known risks associated with remaining construction. As part of this process, WPLP's Owner's Engineer performs a Quantitative Risk Analysis (QRA), determines any changes to the probability and financial impacts of previously identified risks, and considers any risks that can be eliminated as various construction activities are completed. Differences in the contingency percentage for each category of costs reflect differences in the ranges of cost uncertainty attributable to different risk events (e.g. risks associated with EPC activities generally have a much wider range of probability of occurrence and cost impacts than risks associated with non-EPC activities). Based on the latest QRA, no change to contingency requirements has been made for the remaining construction period at this time.[12] As noted below, [redacted] of the contingency requirement has been allocated to EPC change orders, leaving a remaining contingency allowance of $81.9 million.

As at April 30, 2023, WPLP had executed or was in the process of executing EPC change orders in the amount of [redacted], leaving a contingency allowance of $81.9 million. These change orders are reflected in EPC Costs in Table 3 above, which has reduced the contingency allowance by the same amount. Details of the split between EPC contingency allowance, non-EPC contingency allowance, and EPC contract change orders are provided below in Table 4.

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[12] COVID-related costs that are the subject of ongoing commercial discussions with Valard have not been included in the QRA. See Exhibit H-2-2.

Table 4 – Contingency Allowances and EPC Change Order Costs ($000's)

Cost Category	Pre-Contingency Cost Forecast	Contingency (P50) [13]	Contingency %
EPC Costs	1,469,109	79,563	5.4%
EPC Excluded + Other Infrastructure[14]	19,257	398	2.1%
Non-EPC Capital	192,805	1,921	1.0%
Contingency Allowance Subtotal	**1,681,171**	**81,882**	**4.9%**
EPC Change Order Costs		[redacted]	
Total Contingency + Change Order		[redacted]	

The contingency allowance is approximately 4.9% of WPLP's total estimated capital costs before contingency and AFUDC. This compares to the contingency amount in the 2023 transmission rate application, which was approximately 5.6% of the equivalent estimate. This difference is attributable to executed change orders, other costs related to forest fire and MNRF fire prevention order impacts, as well as design changes and route changes that are the subject of commercial discussions with the EPC contractor for the remainder of the construction period.[15] As identified risks to the Project materialize into change orders, or the likelihood and/or magnitude of impacts decrease through the QRA process, contingency is reduced.

Excluding COVID-19 related change order costs, which are addressed in Exhibit H-2-2, the total value of change order costs included in the current cost estimate is approximately [redacted], which represents [redacted]. For change orders relating to risks identified in WPLP's QRA, the contingency allowance is typically reduced in consideration of any change orders, to reflect utilization of the contingency allowance.[16] Exhibits B-1-1 and B-1-2

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[13] COVID-related costs that are the subject of ongoing commercial discussions with Valard have not been included in the contingency amounts as those costs are fully allocated outside of the contingency analysis. See Exhibit H-2-2.

[14] See Section (c) below for discussion of Other Infrastructure costs that were excluded from the LTC cost estimate.

[15] Additional information on the variance is provided in Exhibit C-2-1.

[16] For example, if the QRA identified a risk of cost increase related to a specific routing change, and that routing change was confirmed through a change order, then the change order component of the EPC cost forecast would increase by the amount of the change order and the contingency allowance would decrease to reflect reduction of risk.

provide further discussion of the nature and timing and costs of these EPC contract change orders and Exhibit B-1-4 provides details of WPLP's change management process.

(vii) Capitalized Interest

WPLP's updated forecast for capitalized interest costs is approximately $68.8 million. These costs represent WPLP's estimated total borrowing costs related to the development and construction phases of the Transmission Project. The equivalent forecast for this cost category as provided in the 2023 rate application, was $47.6 million. This difference is attributable to rising construction interest costs at the end of 2022 and beginning of 2023. Details of the project-specific financing obtained by WPLP for the construction phase of the Transmission Project are provided in Exhibit G-2-1.

WPLP notes that it has not included amounts related to capitalized interest in the in-service additions outlined in Exhibit C as it intends to include the total amount of capitalized interest in its 2024 rate base, coincident with the anticipated federal funding that will act as a contribution to offset this amount.

The increase in interest costs is driven primarily by the change in schedule, which results in assets going in-service at a later date, thereby causing more interest to be capitalized. In addition, the market has seen a quick rise in interest rates since the outset of the COVID-19 pandemic.

(c) Other Infrastructure Capital Costs

WPLP's capital expenditure forecast, to the end of 2024, includes approximately $9.25 million for investments in general plant assets that are required to own and operate the Transmission System. These are investments that do not relate directly to the construction of electricity transmission lines or interconnection facilities, but which are otherwise required and include facilities and assets such as service centres, fleet, and business systems. The following table provides a summary of these costs, followed by detailed descriptions for each of the listed cost categories.

Table 5 – Other Infrastructure Capital Expenditure Forecast ($000's)[17]

Category	**2022**	**2023**	**2024**	**Total Forecast**
Facilities (Office and Work Centres)	-	-	5,000	5,000
Fleet	155	40	750	945
Business Systems	-	300	3,000	3,300
Total	**155**	**340**	**8,750**	**9,245**

Approximately $8.75 million (or 63%) of WPLP's forecasted costs for Other Infrastructure are relevant to the determination of WPLP's 2024 revenue requirement in this application, and the nature of these costs are discussed in Sections (i), (ii) and (iii) below. A significant portion of Other Infrastructure assets that were previously planned to be in service in 2023 have been delayed to 2024. WPLP continued to refine its plans for Other Infrastructure requirements and associated cost estimates over the past year. Exhibit B-1-4 provides additional discussion of WPLP's Interim O&M Strategy.

(i) Facilities

WPLP's facilities strategy continues to evolve based on procurement of spare materials and equipment, operating experience with in-service assets and emergency planning discussions with its IMER service provider.[18] WPLP forecasts that service centres will be constructed to service the Line to Pickle Lake and Remote Connection Line segments energized in 2022 and 2023, with in-service dates in 2024, and that any remaining facility investments would be constructed and put into service outside of the Project construction period.

(A) *Operating Centres*

Previously, WPLP had forecasted $11 million for a main operating centre, which was to include office space for operational staff, including provision for control room space and associated software/systems, required IT infrastructure, security systems and backup operating centre. The

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[17] No COVID costs are included.

[18] See Exhibit B-1-4 for further discussion of inspection, maintenance and emergency response activities.

smaller backup operating centre was contemplated to be a stand-alone facility (or space within another facility distinct from the main operating centre) that would be used as a back-up control room only, in the event of an emergency where the main control room could not be used. As further discussed in Exhibit B-1-4, WPLP has executed an agreement with Hydro One to provide interim control room services. WPLP expects to re-evaluate the scope and timing of its longer-term strategy for control room operations, considering the costs and term of its interim control room services agreement with Hydro One, as well as operating experience with this arrangement.

(B) *Service Centres*

Once the Transmission Project is entirely in service, WPLP's transmission system will occupy a geographic footprint spanning approximately 480 km between its southernmost and northernmost points,[19] and approximately 415 km between its westernmost and easternmost points.[20] Based on experience during the construction phase of the project, engagement with Indigenous communities on permanent access plans, and consideration of emergency response scenarios, WPLP's facilities strategy has evolved to include a larger number of smaller service centres, located strategically throughout the project footprint. The need for spare material and equipment to be dispersed between a greater number of locations is primarily due to a combination of limitations in road access, risk of road closures during emergency response scenarios, and weight/range limitations on helicopters that are normally available in Northwestern Ontario. In 2024, WPLP expects to have three service centres operational to service the Line to Pickle Lake as well as the Remote Connection Line segments energized in 2022 and 2023. The initial scope of these service centres will focus on secure storage of spare material and fleet, with the ability to expand the sites and facilities if required in the future.

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[19] This represents the geodesic distance between Dinorwic (which is the southernmost point where WPLP's Line to Pickle Lake connects to HONI's transmission system) and Bearskin Lake First Nation (which is the northernmost point of WPLP's North of Pickle Lake Remote Connection Lines).

[20] This represents the geodesic distance between Poplar Hill First Nation (which is the westernmost point of WPLP's North of Red Lake Remote Connection Lines) and Kasabonika Lake First Nation (which is the easternmost point of WPLP's North of Pickle Lake Remote Connection Lines).

(ii) Fleet

WPLP forecasts Fleet investments of $945k over the 2022-2024 period. These investments are for assets that will include 4-wheel drive pickup trucks, snow machines, off-road vehicles and trailers, which are required for routine inspections and maintenance as well as emergency access to WPLP's transmission system. The current estimates are based on purchasing these assets due to the high number of kilometres and extensive off-road use that are likely to be required. WPLP's 2024 forecasted fleet purchases include pickup trucks, snow machines, off-road vehicles and trailers required for operations, maintenance and emergency response.

WPLP currently expects that fleet requirements for major construction and repairs, such as large off-road tracked vehicles and helicopters, would be sourced on an as-needed basis (i.e. rental or through contractors retained to perform certain work), with consideration of retainers to ensure adequate availability when needed.

(iii) Business Systems

WPLP forecasts Business System investments of $3.3 million, of which $0.3 million is expected to be put into service in 2023 with the completion of WPLP's Asset Management system. These investments consist of purchases of ERP and Asset Management systems and related software, which are required for WPLP's accounting and financial management/reporting requirements, inventory management, work management and the implementation of a comprehensive asset management program.

(iv) Initial Inventory, Tools & Equipment

WPLP previously forecasted investments in Initial Inventory, Tools and Equipment of $9.8 million over the 2022-2024 period. These investments will now be purchased through working capital based on WPLP's assessment of its operating inventory requirements. Based on its review of assets and required inventory, none of the inventory items would be classified as major spare parts or stand-by equipment and therefore do not qualify as property, plant and equipment and are not included as part of total capital costs in the Project. As WPLP, is not seeking an allowance for working capital in the 2024 Test Year, further inventory details will be provided as part of first multi-year rate application.

(d) COVID-19 Costs[21]

The transfer of COVID-19 costs to CWIP Account 2055 from 2021-2023 CCCDA is described in Exhibits H-2-1 and H-2-2. Subcategories of COVID-19 costs are provided below in Table 6 which are consistent with the costs described in detail in the 2023 rate application Exhibit H-2-2.

Table 6 – COVID-19 Cost Forecast ($000's)

Cost Category	Cost ($000's)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
	74,570

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[21] This does not include any costs that may be recorded in the proposed EPC COVID-Related Costs Deferral Account or in the 2021-2023 CCCDA (as proposed to be amended) upon the conclusion of the commercial discussions between WPLP and its EPC contractor.

Appendix 'A'

Overhead Cost Allocation Methodology

WPLP's forecast of its general overhead costs is presented in Table A-1 below. Overhead costs are comprised of costs such as internal labour (including departmental costs and overheads), services provided by third-party consultants and professionals of a general nature, costs related to continued Indigenous engagement and participation in the project, general administrative costs, and stakeholder engagement costs. Prior to Pikangikum becoming grid-connected on December 20, 2018, WPLP did not have any assets in service and all overhead costs were recorded as capital development costs. Between January 2019 and December 2024, WPLP expects to incur total overhead costs as presented in Table A-1, and WPLP has capitalized these costs on a declining basis, with the balance allocated to OM&A, using the methodology set out below.

Table A-1 – Overhead Costs During the Construction Period

Category	**Forecast Overhead Costs 2019-2024 ($000's)**
Labour and Departmental Costs	
Labour and Affiliate Services	32,032
Equipment and Supplies	542
Software	490
Meetings	522
Training	341
Travel	4,489
Rents	8,565
Other	194
	47,173
Environmental Services	**4,793**
Other Consultants (Allocate)	
Legal	1,501
Advisory Services	5,229
Audit Fees	323
IT Support Services	301
Other	272
	7,626

Indigenous Engagement & Communications	
Affiliate Services	5,485
Contracted Services	6,575
Meetings	1,754
Travel	867
Other	1,793
	16,473
Stakeholder Engagement	
Affiliate Services	74
Contracted Services	38
Meetings	11
Travel	80
Other	196
	399
Indigenous Participation and Training	
Affiliate Services	7,793
Contracted Services	4,596
Meetings	2,567
Travel	1,854
Other	1,643
	18,452
Administrative Costs	
Affiliate Services	6,932
Office Supplies	1,016
Rent	406
Utilities	159
Other	31
	8,551
Total	**103,460**

Allocation Methodology

For purposes of cost recovery, the overhead costs summarized in Table A-1 must be capitalized or allocated to OM&A. To accomplish this, WPLP has calculated the costs identified in Table A-1 on a quarterly basis from Q1 2019 to Q4 2024, and the resulting costs for each quarter are multiplied by allocation factors that are determined based on the relative percentage of assets in-service in each month.[22] Using this methodology, the capitalization of overhead costs declines over time from complete capitalization during project development, a predominantly capital allocation until mid-2022 (during which period only the Pikangikum assets are in service and WPLP is primarily focused on construction), to a blended allocation from 2022 to 2024 during which period WPLP will be balancing construction and operation of in-service assets, and ultimately to a 100% OM&A allocation in 2025 when all assets are expected to be in service (subject to any minor ongoing capital costs incurred in the immediate years thereafter).

Tables A-2 and A-3 below illustrate the calculation of these quarterly allocation factors.

Table A-2 – Total Line and Station Capital Costs

Item	**Costs ($000's)**
EPC Contract Costs	1,432,779
EPC Contingency + Change Order	115,892
Pikangikum Costs	61,000
Total Line and Station Costs	**1,609,671**

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[22] In the context of this methodology “total line and station capital costs” reflect total costs associated with the 2018 construction of the Pikangikum system, plus the total forecasted EPC costs (i.e. contract + contingency + change orders) related to the construction of WPLP’s transmission system. “Assets in service” reflects the portion of these costs related to assets that are forecasted to be in service at the end of each month, based on the most recent project schedule. The “asset in service” amounts in this Appendix are therefore different that the “in service addition” amounts that are described in detail in Exhibit C.

1 **Table A-3 – Calculation of Cost Allocation Factors**

Qtr	**Month**	**Cumulative Assets in Service**[23]		**Cost Allocation**[24]	
		Amount ($000's)	**% of Total**	**% OM&A**	**% Capitalization**
Q1 2019	Jan-19	61,000	3.8%	3.8%[25]	96.2%
	Feb-19	61,000	3.8%		
	Mar-19	61,000	3.8%		
No change from Q1 2019 to Q2 2022					
Q3 2022	Jul-22	61,000	3.8%	14.5%	85.2%
	Aug-22	314,068	19.5%		
	Sep-22	323,996	20.1%		
Q4 2022	Oct-22	566,242	35.2%	38.8%	61.2%
	Nov-22	652,915	40.6%		
	Dec-22	652,915	40.6%		
Q1 2023	Jan-23	653,706	40.6%	40.6%	59.4%
	Feb-23	653,706	40.6%		
	Mar-23	653,706	40.6%		
Q2 2023	Apr-23	653,706	40.6%	42.5%	57.5%
	May-23	700,161	43.5%		
	Jun-23	700,161	43.5%		
Q3 2023	Jul-23	927,121	57.6%	59.1%	40.9%
	Aug-23	962,810	59.8%		
	Sep-23	962,810	59.8%		
Q4 2023	Oct-23	962,810	59.8%	62.7%	37.3%
	Nov-23	1,032,578	64.1%		
	Dec-23	1,032,578	64.1%		
Q1 2024	Jan-24	1,032,578	64.1%	64.1%	35.9%
	Feb-24	1,032,578	64.1%		
	Mar-24	1,032,578	64.1%		

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[23] In forecasting the in-service asset value by month, the EPC contingency allowance and change order costs were prorated based on the pre-contingency forecast of in-service additions.

[24] The percentage allocations are based on the cost estimates presented in this application, and may vary marginally as the contingency allowance is either utilized or reduced.

[25] The allocation to OM&A from Q1 2019 to Q2 2022 is based on the value of Pikangikum assets, notwithstanding that the capital cost of these assets was funded by the Government of Canada and is therefore not added to WPLP's rate base. The overhead costs allocated to OM&A during this period are being recorded in WPLP's Distribution System Deferral Account. Once other transmission assets come into service, WPLP would stop recording overhead costs allocated to OM&A in the Distribution System Deferral Account and would begin recording these costs in transmission OM&A accounts.

Q2 2024	Apr-24	1,173,499	72.9%	80.3%	19.7%
	May-24	1,290,400	80.2%		
	Jun-24	1,411,889	87.7%		
Q3 2024	Jul-24	1,458,489	90.6%	95.2%	4.8%
	Aug-24	1,530,109	95.1%		
	Sep-24	1,609,671	100.0%		
100% allocated to OM&A for Q3/Q4 2024					

Table A-4 below summarizes the overall result of applying the allocation and capitalization factors from Table A-3 to the overhead costs in Table A-1. Exhibit C-6-1 provides a description of WPLP's capitalization policy, as it applies to capital costs incurred after construction of the Transmission Project is complete.

Table A-4 – Allocation of Forecasted Overhead Costs

Category	**Item**	**Forecasted Overhead Costs 2019-2024 ($000's)**		
		Capital	**OM&A**	**Total**
Overhead	Labour and Departmental Costs	31,102	16,071	47,173
	Environmental Services	4,271	523	4,793
	Other Consultants (Allocate)	5,465	2,161	7,626
	Indigenous Engagement & Communications	10,402	6,071	16,473
	Stakeholder Engagement	346	53	399
	Indigenous Participation and Training	12,962	5,490	18,452
	Administrative Costs	6,115	2,428	8,543
	Total	**70,663**	**32,797**	**103,460**

Exhibit B, Tab 2, Schedule 1

Asset Categorization

ASSET CATEGORIZATION

The purpose of this schedule is to categorize the Transmission System assets into the various transmission rate pools and to identify which assets are part of the bulk electricity system, as defined by the North American Electric Reliability Corporation (NERC). This categorization supports the cost allocation in Exhibit I and is responsive to certain requirements described in Section 2.4.1 of the Filing Requirements. For ease of reference, tables summarizing the operational designation, geographical reference, voltage level, categorization, and bulk electricity system status are provided in **Appendix 'A'** (Stations) and **Appendix 'B'** (Transmission Line Segments).

The relevant asset categories for WPLP, each of which is described below, are Network, Line Connection, Transformation Connection, and Common.

A. Network Assets

In its Decision and Order in EB-2018-0190, the OEB confirmed that the Line to Pickle Lake is classified as a network facility and that the revenue requirement associated with the Line to Pickle Lake will be recovered through the UTR network charge.[1] The revenue requirement associated with the Line to Pickle Lake has formed part of the UTR network charge since April 1, 2022 per EB-2022-0084. The Line to Pickle Lake includes:

a) a 230 kV switching station located adjacent to Hydro One circuit D26A approximately 9 km southeast of Dinorwic (the "Dinorwic SS");

b) an approximately 303 km single circuit, overhead, 230 kV transmission line running from the Wataynikaneyap SS generally in a northeasterly direction to the Wataynikaneyap TS (described below) (the "Line to Pickle Lake"); and

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[1] EB-2018-0190, Decision and Order, p.23

c) a 230/115 kV transformer station located near the intersection of Hwy 599 and Cohen Avenue in Central Patricia, which is approximately 3 km northeast from the Town of Pickle Lake (the "Pickle Lake TS").

Additionally, Exhibit D-1-2 in EB-2018-0190 describes the network assets that HONI has constructed at each of Dinorwic, Pickle Lake and Red Lake for the purpose of interconnecting WPLP's transmission system to HONI's existing transmission facilities. Since the assets in question are Network assets, WPLP includes these costs along with the costs related to the Line to Pickle Lake assets identified above for recovery through the UTR network charge.[2]

In the final SIA Report for CAA ID 2016-567, the IESO identified that all of WPLP's Line to Pickle Lake assets fall within the NERC definition of the Bulk Electric System (BES). None of WPLP's other assets meet the BES definition.

B. Line Connection and Transformation Connection Assets

All assets comprising the Remote Connection Lines are categorized as either line connection or transformation connection assets. Several aspects arising from the EB-2018-0190 proceeding are worth noting in relation to the categorization of these assets:

a) The OEB deemed the 44 kV and 25 kV portions of the Remote Connection Lines to be transmission facilities;[3]

b) The OEB approved a cost recovery and rate framework that results in the revenue requirement associated with the Remote Connection Lines (based on direct and indirect capital expenditures and OM&A expenses) being recovered via a fixed monthly charge applicable to Hydro One Remote Communities Inc. (HORCI), instead of being recovered through UTRs;[4] and

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[2] EB-2018-0190, Response to Supplemental IR C-Staff-66.

[3] EB-2018-0190, Decision and Order, p.23

[4] EB-2018-0190, Decision and Order, pp. 24-28

c) Notwithstanding that the fixed monthly charge described in (b) above does not distinguish between line connection and transformation connection assets, WPLP maintains the distinction between these categories to align with the UTR rate pools.[5]

WPLP's line connection assets will include approximately 1438[6] km of single circuit overhead 115 kV, 44 kV and 25 kV transmission lines running from the Pickle Lake and Red Lake areas generally in a northerly direction, to a number of switching and transformer stations, as well as five switching stations that do not contain transformers. Specifically, WPLP's transformation connection assets will include 15 transformer stations from which transmission service will be provided to distribution systems owned and operated by HORCI, which in turn will serve customers in 16 remote Indigenous communities.[7]

C. Common Assets

WPLP's common assets will include general plant assets such as fleet, facilities, tools and equipment, IT hardware and software, and business systems. For rate setting purposes, the rate base amounts related to these assets will be allocated between the Line to Pickle Lake and the Remote Connection Lines (i.e. Network Assets vs. Line and Transformation Connection Assets) when WPLP calculates its revenue requirement. Exhibit I-2-1 illustrates the allocation of general plant rate base for the 2024 Test Year.

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[5] In response to various IR's in EB-2018-0190 (e.g. C-Staff-70(c), HORCI Supplemental IR 7), WPLP confirmed that it proposes to charge UTR's in the normal course to any connecting customers other than HORCI, and that it proposes to evaluate CIAC requirements with respect to new connections in accordance with TSC requirements. This implicitly requires that WPLP maintain distinct categorization between line connection and transformation connection assets.

[6] As described on page 6 of Exhibit B Tab 1, Schedule 1, the total line length has been adjusted by 3 km since EB-2022-0149 to reflect as-built and/or ground surveyed values and subtraction of line lines related to assets that will be transferred to HORCI.

[7] One of the 15 transformer stations (North Spirit Lake TS) is designed to accommodate the future connection of a 17th community, McDowell Lake First Nation.

EB-2023-0168
Exhibit B
Tab 2
Schedule 1
Appendix 'A'
Page **1** of **3**

APPENDIX 'A'

Summary of WPLP Substations

Designation	Name	Location[1]	Voltage	Functionality[2]	Asset Categorization
Line to Pickle Lake (Bulk Electricity System):					
A	Wataynikaneyap SS	SE of Dinorwic	230 kV	Switching; Reactive Power Compensation	Network
B	Wataynikaneyap TS	NE of Pickle Lake	230/115 kV	Transformation; Switching; Reactive Power Compensation	Network
North of Pickle Lake Remote Connection Lines (non-Bulk Electricity System):					
C	Ebane/Pipestone Jct	NW of Nord Road / Pipestone River crossing	115 kV	Switching; Reactive Power Compensation	Line Connection
J	Kingfisher Lake TS	NW of Kingfisher Lake Airport	115/44/25 kV	Switching; Transformation; Reactive Power Support	Transformation Connection
I	Wunnumin Lake TS	South of Wunnumin Lake Airport	44/25 kV	Transformation	Transformation Connection
K	Wawakapewin TS	South of Wawakapewin First Nation Reserve boundary	115/44/25 kV	Switching; Transformation; Reactive Power Support	Transformation Connection
L	Kasabonika Lake TS	SW of Kasabonika Lake Airport	44/25 kV	Transformation	Transformation Connection
M	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	Approximate mid-point between the 2 communities	115/25 kV	Transformation	Transformation Connection
D	North Caribou Lake TS	North of Weagamow Lake Airport	115/25 kV	Switching; Transformation	Transformation Connection
E	Muskrat Dam TS	~12 km NE of Muskrat Dam Airport	115/25 kV	Switching; Transformation; Reactive Power Compensation	Transformation Connection
F	Bearskin Lake TS	SE of Bearskin Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection
G	Sachigo Lake TS	North of Sachigo Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection

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[1] Locations are within 5 km of reference point unless otherwise noted. Exhibit C-2-1 (In-Service Additions) contains more specific location descriptions for assets with 2024 in-service dates.

[2] In the context of this table, “Switching” is meant to indicate which substations have switching/protection functionality between an incoming transmission line and one or more outgoing transmission lines. All stations that contain transformation and/or reactive power functionality have switching and protection features related to that functionality.

Designation	**Name**	**Location**[1]	**Voltage**	**Functionality**[2]	**Asset Categorization**
North of Red Lake Remote Connection Lines (non-Bulk Electricity System):					
P	Red Lake SS	SE of Hydro One Red Lake TS (West of Hwy 105)	115 kV	Switching; Reactive Power Compensation	Line Connection
Q	Pikangikum TS	~11 km SE of Pikangikum Airport (South of Berens River)	115/25 kV[3]	Switching; Transformation	Transformation Connection
R	Poplar Hill SS	~30 km East of Poplar Hill First Nation	115 kV	Switching; Reactive Power Compensation	Line Connection
S	Poplar Hill TS	East of Poplar Hill Airport	115/25 kV	Transformation	Transformation Connection
T	Deer Lake SS	~20 km SE of Deer Lake Airport	115 kV	Switching; Reactive Power Compensation	Line Connection
U	Deer Lake TS	SE of Deer Lake Airport	115/25 kV	Transformation	Transformation Connection
Z	Sandy Lake SS	~55 km South of Sandy Lake Airport	115 kV	Switching; Reactive Power Compensation	Line Connection
W	Sandy Lake TS	West of Sandy Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection
V	North Spirit Lake TS	SW of North Spirit Lake Airport	115/44/25 kV[4]	Switching; Transformation	Transformation Connection
Y	Keewaywin TS	NE of Keewaywin Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection

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[3] Interim operation at 44 kV was converted to 115 kV operation on May 12, 2023.

[4] 44 kV winding is available on the transformer to permit a future supply to McDowell Lake First Nation at 44 kV.

APPENDIX ‘B’

Summary of WPLP Line Segments

Designation	Origin	Endpoint	Voltage (kV)	Length (km)	Asset Categorization
Line to Pickle Lake (Bulk Electricity System):					
W54W	Wataynikaneyap SS	Wataynikaneyap TS	230	303.4	Network
North of Pickle Lake Remote Connection Lines (non-Bulk Electricity System):					
WBC	Pickle Lake TS	Ebane/Pipestone SS	115	147.9	Line Connection
WCD	Ebane/Pipestone SS	North Caribou Lake TS	115	132.9	Line Connection
D1	North Caribou Lake TS	HORCI 25 kV Demarcation	25	1.5	Line Connection
WDE	North Caribou Lake TS	Muskrat Dam TS	115	99.5	Line Connection
E1	Muskrat Dam TS	HORCI 25 kV Demarcation	25	15.0	Line Connection
WEF	Muskrat Dam TS	Bearskin Lake TS	115	63.1	Line Connection
F1	Bearskin Lake TS	HORCI 25 kV Demarcation	25	0.02	Line Connection
WEG	Muskrat Dam TS	Sachigo Lake TS	115	83.9	Line Connection
G1	Sachigo Lake TS	HORCI 25 kV Demarcation	25	3.2	Line Connection
WCJ	Ebane/Pipestone SS	Kingfisher Lake TS	115	98.2	Line Connection
J1	Kingfisher Lake TS	HORCI 25 kV Demarcation	25	4.0	Line Connection
WJI	Kingfisher Lake TS	Wunnumin Lake TS	44	55.5	Line Connection
I1	Wunnumin Lake TS	HORCI 25 kV Demarcation	25	1.0	Line Connection
WJK	Kingfisher Lake TS	Wawakapewin TS	115	84.7	Line Connection
K1	Wawakapewin TS	HORCI 25 kV Demarcation	25	4.8	Line Connection
WKL	Wawakapewin TS	Kasabonika Lake TS	44	39.5	Line Connection
L1	Kasabonika Lake TS	HORCI 25 kV Demarcation	25	2.6	Line Connection
WKM	Wawakapewin TS	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	115	65.5	Line Connection
M1	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	HORCI 25 kV Demarcation	25	0.3	Line Connection

Designation	Origin	Endpoint	Voltage (kV)	Length (km)	Asset Categorization
North of Red Lake Remote Connection Lines (non-Bulk Electricity System):					
WPQ[1]	Red Lake SS	Pikangikum TS	115	115.8	Line Connection
Q1	Pikangikum TS	HORCI 25 kV Demarcation	25	17.6	Line Connection
WQR	Pikangikum TS	Poplar Hill SS	115	42.6	Line Connection
WRS	Poplar Hill SS	Poplar Hill TS	115	32.7	Line Connection
S1	Poplar Hill TS	HORCI 25 kV Demarcation	25	1.4	Line Connection
WRT	Poplar Hill SS	Deer Lake SS	115	67.9	Line Connection
WTU	Deer Lake SS	Deer Lake TS	115	20.6	Line Connection
U1	Deer Lake TS	HORCI 25 kV Demarcation	25	0.01	Line Connection
WTZ	Deer Lake SS	Sandy Lake SS	115	27.6	Line Connection
WZW	Sandy Lake SS	Sandy Lake TS	115	96.1	Line Connection
W1	Sandy Lake TS	HORCI 25 kV Demarcation	25	0.3	Line Connection
WZV	Sandy Lake SS	North Spirit Lake TS	115	31.7	Line Connection
V1	North Spirit Lake TS	HORCI 25 kV Demarcation	25	1.6	Line Connection
WVY	North Spirit Lake TS	Keewaywin TS	115	78.7	Line Connection
Y1	Keewaywin TS	HORCI 25 kV Demarcation	25	0.3	Line Connection

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[1] 95.5 km of the WPQ line segment was constructed in 2018 as part of the 98.9 km 44 kV line that was constructed between Hydro One’s 44 kV system near Red Lake and the Pikangikum TS. The remaining 20.3 km of 115 kV line was constructed between the Red Lake TS and the existing 44 kV Pikangikum Line, which became the new transmission supply and resulted in the entire WPQ line segment operating at 115 kV following a voltage conversion outage on May 12, 2023. The remaining 3.4 km (98.9 km constructed less 95.5 km converted to 115 kV) of the 44 kV distribution line constructed in 2018 will be decommissioned as part of the EPC contract scope of work.

Exhibit B, Tab 3, Schedule 1

Regional Considerations

REGIONAL CONSIDERATIONS

Section 2.4.2 of the Filing Requirements specifies that, where applicable, a transmitter shall file as part of their TSP information on the regional planning processes in which they are a participant and information demonstrating that regional considerations have been appropriately considered and addressed in the development of the transmitter's plans. While the manner in which WPLP has participated in regional planning processes and the way in which regional considerations have been considered in WPLP's plans are not typical, there is significant alignment between the development of WPLP's Transmission System, provincial policy objectives as outlined in Long-term Energy Plans ("LTEP"), and the OEB's regional planning process. The historical context for this is discussed below.

A. Alignment with Long-Term Energy Plans

In 2010, the Province issued its first LTEP. In the 2010 LTEP the Province declared that it considered the Line to Pickle Lake to be a priority project and indicated its intention to ask the Ontario Power Authority ("OPA") to develop a plan for remote connections beyond Pickle Lake.[1] Following up on that intention, in a February 17, 2011 Directive the Minister of Energy asked the OPA to develop a plan for remote community connections beyond Pickle Lake. In 2013, the Province issued its second LTEP. In the 2013 LTEP the Province declared not only that it continued to consider the Line to Pickle Lake to be a priority project, but also that it considered connecting remote communities in northwest Ontario to be a priority for the province.[2]

Subsequent to the 2013 LTEP, on August 21, 2014 the OPA issued its Draft Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario for the Northwest Ontario First Nation Transmission Planning Committee ("Draft Remote

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[1] Ministry of Energy, Building Our Clean Energy Future – Ontario's Long-Term Energy Plan, November 23, 2010, p. 46 (http://www.nexteraenergycanada.com/pdf/ontario_ltep.pdf)

[2] Ministry of Energy, Achieving Balance - Ontario's Long-Term Energy Plan, December 2013, pp. 52 and 72 (http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf)

Community Connection Plan" or "Draft RCCP").[3] This report established a business case for connecting up to 21 remote communities in northwestern Ontario to the provincial transmission system, including the 16 communities that will be connected to WPLP's transmission system.[4]

B. Alignment with OEB Regional Planning Process

In the Northwest Ontario Planning Region (Northwest), the first cycle of the regional planning process divided the region into four sub-regions, each with their own Integrated Regional Resource Plan (IRRP) published between January 2015 and December 2016. WPLP's transmission system is located in the North of Dryden sub-region, for which an IRRP was published by the IESO in January 2015.[5] This report recommended, among other things, a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake in order to reinforce supply to Pickle Lake and provide capacity for the connection of remote communities north of Pickle Lake and north of Red Lake as recommended by the RCCP.

The first cycle of regional planning for the Northwest concluded in June 2017 with the publication of the Regional Infrastructure Plan (RIP).[6] The RIP confirms the recommendations of the 2015 North of Dryden IRRP with respect to the Line to Pickle Lake and the connection of 16 remote communities and acknowledges WPLP's development of the related transmission project.

The second cycle of regional planning for the Northwest started in March 2020 and was completed with the release of the Northwest Region Integrated Regional Resource Plan on January 13, 2023 (2023 IRRP). The 2023 IRRP acknowledges the role of WPLP's transmission system in meeting capacity and operational needs in Northwestern Ontario. The 2023 IRRP identifies that moving

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[3] See http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/remote-community-connection/OPA-technical-report-2014-08-21.pdf?la=en

[4] WPLP's transmission system will also allow for the potential future grid connection of a 17th community (McDowell Lake First Nation), which does not currently have a community distribution network. Additionally, the five other communities in the Ring of Fire area which the RCCP determined were economic to connect could be connected to the provincial transmission system via WPLP's transmission system at a future date.

[5] See http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/North-of-Dryden/North-Dryden-Report-2015-01-27.pdf?la=en

[6] See https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/northwestontario/Documents/Northwest%20RIP%20Report%20-%202017June9.pdf

the open point on HONI's E1C transmission line to supply load in the Pickle Lake subsystem from WPLP's transmission system will cause post-contingency high voltage concerns during certain operating scenarios. Additional reactors are required on the HONI system at/near Pickle Lake SS to manage these high voltages and the 2023 IRRP recommends that HONI and IESO collaborate during the 2023 Northwest Regional Infrastructure Plan (2023 RIP) to refine the location of the open point and reactor sizing. WPLP has participated in the 2023 RIP kick-off meeting and has also had additional discussions with HONI and IESO to consider the feasibility of alternative open point locations to address system capacity and reliability considerations until additional reactors can be installed on the HONI system.

C. Coordinated Planning with Third Parties

Each of the regional planning initiatives described above (the RCCP, IRRP and RIP, as well as 2023 IRRP and RIP) included significant engagement between a variety of parties:

- In preparing the Draft RCCP, the OPA/IESO engaged with 17 of the First Nation communities included in the plan, and discussed its intent to finalize the report only following engagement with all 25 communities.[7]

- In preparing the 2023 IRRP, the IESO identified 65 First Nation communities and eight Métis communities that were invited to six webinars. Further, the IESO engaged with a number of First Nations organizations, municipalities, industry associations, LDCs and transmitters (including WPLP).

- In preparing the 2023 RIP, Hydro One Transmission included input from a working group that includes the IESO, Hydro One Distribution, four LDC's and two neighbouring transmitters (WPLP and Nextbridge). The 2023 RIP will also consider the results from the other regional planning reports mentioned above, specifically the 2023 IRRP.

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[7] RCCP; pp. 91-92

Exhibit C, Tab 1, Schedule 1

Rate Base Overview

RATE BASE OVERVIEW

This Exhibit provides WPLP's forecasted rate base for the 2024 test year, and a description of each component of the forecasted rate base. Given that this is the third revenue requirement application filed by WPLP and is in respect of the third year in which WPLP will have transmission assets in service, this Exhibit provides information only pertaining to the 2024 Test Year, the 2023 Bridge Year, the 2022 Historical Year and the associated variance analysis between those years. As no transmission assets were in service prior to 2022, WPLP does not have historical actual data other than for 2022, during which the Line to Pickle Lake and segments of the Remote Connection Lines connecting two communities were in service for part of the year.

A. Rate Base Forecast

WPLP's proposed rate base for the 2024 test year is based on a forecast of net fixed assets[1], calculated using the 12-month average of gross assets and accumulated depreciation, consistent with WPLP's approach in its prior rate applications.

Given that portions of the Remote Connection Lines will continue to come into service at different points during the 2024 test year, and consistent with the approach taken in WPLP's prior rate applications, it is more appropriate to calculate the proposed rate base by applying a 12-month average of forecast monthly in-service additions, including with respect to minor sustaining capital. This will result in the same value as the traditional "half-year rule" for those assets that will be in-service for the entirety of the 2024 rate year (i.e. the Line to Pickle Lake and certain segments of Remote Connection Lines). WPLP plans to use the "half-year rule" once the Transmission Project is complete and all assets are in-serviced.

WPLP's proposed rate base methodology apportions WPLP's revenue requirement more accurately between the distinct customer groups that will benefit from each group of assets, while also better reflecting the timing of assets coming into service. As described in Exhibit C-3-1, the

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[1] Net fixed assets are calculated as gross plant in service minus accumulated depreciation and minus any contributed capital. WPLP is not requesting an allowance for working capital in 2024 but intends to do so in its first multi-year rate application.

Network pool will be receiving the full benefit from the Line to Pickle Lake throughout 2024, whereas HORCI will benefit from the Remote Connection Lines based on the portions of those lines that are expected to be in service for the entirety of 2024 and the additional portions of the Remote Connection Lines that are expected to come into service at different points throughout 2024.

WPLP’s approved and budgeted rate base for the 2022 historical year and the 2023 bridge year are summarized in Tables 1 and 2, below. Forecasted rate base for the 2024 test year is provided in Table 3.

Table 1 – 2022 Rate Base

Item	**2022 Approved ($000's)**			**2022 Actual ($000's)**			**Variance 12-Month Avg**
	Opening	**Closing**	**12-Month Avg**	**Opening**	**Closing**	**12-Month Avg**	
Gross Fixed Assets	0	679,135	420,879	0	679,343	182,627	(238,252)
Less Accumulated Depreciation	0	(7,887)	(2,328)	0	(3,104)	(418)	1,910
Net Fixed Assets	**0**	**671,248**	**418,552**	**0**	**676,238**	**182,209**	**(236,343)**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**0**	**671,248**	**418,552**	**0**	**676,238**	**182,209**	**(236,343)**

Table 2 – 2023 Rate Base

Item	**2023 Approved ($000's)**			**2023 Budget ($000's)**			**Variance 12-Month Avg**
	Opening	**Closing**	**12-Month Avg**	**Opening**	**Closing**	**12-Month Avg**	
Gross Fixed Assets	680,519	1,035,460	856,483	679,343	1,114,064	857,638	1,155
Less Accumulated Depreciation	(4,179)	(21,229)	(11,826)	(3,104)	(20,024)	(10,629)	1,197
Net Fixed Assets	**676,340**	**1,014,232**	**844,657**	**676,238**	**1,094,040**	**847,009**	**2,352**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**676,340**	**1,014,232**	**844,657**	**676,238**	**1,094,040**	**847,009**	**2,352**

Table 3 – 2024 Rate Base

Item	2024 Forecast ($000's)		
	Opening	**Closing**	**12-Month Avg**
Gross Fixed Assets	1,114,064	1,755,808	1,506,409
Less Accumulated Depreciation	(20,024)	(50,457)	(33,803)
Net Fixed Assets	**1,094,040**	**1,705,351**	**1,472,606**
Working Capital Allowance	-	-	-
Total Rate Base	**1,094,040**	**1,705,351**	**1,472,606**

Details of WPLP's 2024 in-service additions by asset category and type of assets are provided in Exhibit C-2-1. WPLP's proposal to calculate gross fixed asset and accumulated depreciation values using an average of twelve-month values is further articulated in Exhibit C-3-1.

B. Variance Analysis

WPLP's actual 12-month average rate base for 2022 is $236 million lower than the 2022 OEB-approved value from the initial rate application. This variance is primarily driven by the delayed in-service date of the Line to Pickle Lake, from April 2022 to August 2022, and the delayed in-service date of certain segments of the Remote Connection Lines, from June 2022 to October 2022. The delay in the in-service dates significantly reduced the 12-month average rate base forecast, as the assets were in-service for a shorter period during 2022.

The change in rate base from 2022 actuals to 2023 forecast is the addition of 6[2] community segments expected to be connected in 2023. WPLP's 12-month average rate base budget for 2023 is $2.4 million higher than the 2023 OEB approved value from the 2023 rate application. The primary driver of this variance is the energization of Sachigo Lake First Nation in November 2023 versus May 2024. Additional details on the variances in 2023 are provided in Exhibit C-2-1.

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[2] This does not include the line segments or substations associated with the Pikangikum Distribution System that are already in service and were transitioned to a transmission supply on May 12, 2023.

The change in rate base from 2023 budget to 2024 forecast is representative of the remaining community segments being energized, which includes 9 substations and 16 line segments. In addition, this change reflects COVID-19 related costs incurred between January 2021 and December 31, 2023. The COVID-19 costs relate to those assets already in service in 2022 and 2023 and those assets going into service in 2023 and 2024.

Exhibit C, Tab 2, Schedule 1

In-Service Additions

IN-SERVICE ADDITIONS

In total, the Transmission Project is comprised of 22 stations (6 switching stations and 16 transformer stations) and 35 distinct line segments – running from one station to another, or from a station to a HORCI-owned[1] and operated distribution system serving a remote community – that will be operated at four different voltages (230 kV, 115 kV, 44 kV and 25 kV) over a total distance of approximately 1,742 km[2]. As described in Exhibit B, Tab 1, Schedule 3, during 2022, WPLP put into service the Line to Pickle Lake component of the Transmission Project, as well as those portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at North Caribou Lake First Nation and Kingfisher Lake First Nation. In 2023, WPLP plans to put into service those portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at Muskrat Dam First Nation, Bearskin Lake First Nation, Wawakapewin First Nation, Wunnumin Lake First Nation, Sachigo Lake First Nation and Kasabonika Lake First Nation, and those portions of the Red Lake Remote Connection Lines that are needed to provide transmission service to HORCI at Pikangikum First Nation.[3]

In 2024, WPLP plans to put into service those portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at Kitchenuhmaykoosib Inninuwug, Wapekeka First Nation, and those portions of the Red Lake Remote Connection Lines that are needed to provide service to HORCI at Poplar Hill First Nation, Deer Lake First Nation, North Spirit Lake First Nation, Sandy Lake First Nation and Keewaywin First Nation.

The specific line segments and substations that comprise the 2024 test year in-service additions are summarized in Table 1 and described below. Details of the allocation of capital costs to each fixed asset (i.e. each line segment and substation) are provided in **Appendix 'A'**. A map

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[1] HORCI continues to work with the IPA communities. An update on progress has been provided in the Semi-Annual Report dated April 17, 2023, filed pursuant to EB-2018-0190.

[2] As described on page 10 of Exhibit B-1-1, there have been a number of minor route changes that have decreased the overall line length by approximately 2 km (less than 1%). As such, the total length indicated here has been adjusted by 2 km as compared to the previous application under EB-2022-0149.

[3] On May 12, 2023, the Pikangikum Distribution System was converted to a transmission supply and now forms part of WPLP's Transmission System.

highlighting the portions of the Transmission System that are forecasted to be in service by the end of 2024 is provided in **Appendix 'B'**.

Table 1 – 2024 Transmission System In-Service Additions by Asset

Asset Designation	**Description**	**2024 In-Service Additions ($000's)**	**COVID-19 Costs ($000's)**	**Total ($000's)**
2024 In-Service Asset Additions				
Line WKM	115 kV - Wawakapewin TS to Wapekeka-KI TS	44,092	[redacted]	[redacted]
Line WM+ (25kV)	25 kV - Wapekeka-KI TS to HORCI KI	167	[redacted]	[redacted]
Line WM- (25kV)	25 kV - Wapekeka-KI TS to HORCI Wapekeka	609	[redacted]	[redacted]
Line WQR	115 kV - Pikangikum TS to Poplar Hill SS	40,406	[redacted]	[redacted]
Line WRS	115 kV - Poplar Hill SS to Poplar Hill TS	26,542	[redacted]	[redacted]
Line WS1 (25kV)	25 kV - Poplar Hill TS to HORCI Poplar Hill	1,947	[redacted]	[redacted]
Line WRT	115 kV - Poplar Hill SS to Deer Lake SS	78,319	[redacted]	[redacted]
Line WTU	115 kV - Deer Lake SS to Deer Lake TS	25,246	[redacted]	[redacted]
Line WU1 (25kV)	25 kV - Deer Lake TS to HORCI Deer Lake	156	[redacted]	[redacted]
Line WTZ	115 kV - Deer Lake SS to Sandy Lake SS	26,337	[redacted]	[redacted]
Line WZW	115 kV - Sandy Lake SS to Sandy Lake TS	80,023	[redacted]	[redacted]
Line W1 (25kV)	25 kV - Sandy Lake TS to HORCI Sandy Lake	264	[redacted]	[redacted]
Line WZV	115 kV - Sandy Lake SS to North Spirit Lake TS	27,164	[redacted]	[redacted]
Line WV1 (25kV)	25 kV - North Spirit Lake TS to HORCI North Spirit Lake	643	[redacted]	[redacted]
Line WVY	115 kV - North Spirit Lake TS to Keewaywin TS	64,589	[redacted]	[redacted]
Line WY1 (25kV)	25 kV - Keewaywin TS to HORCI Keewaywin	728	[redacted]	[redacted]
Subtotal RCL Lines		*415,883*	[redacted]	[redacted]
			[redacted]	[redacted]
Station M	Wapekeka TS	18,716	[redacted]	[redacted]
Station R	Poplar Hill SS	12,885	[redacted]	[redacted]
Station S	Poplar Hill TS	13,693	[redacted]	[redacted]
Station T	Deer Lake SS	13,372	[redacted]	[redacted]
Station U	Deer Lake TS	14,250	[redacted]	[redacted]
Station V	North Spirit Lake TS	24,264	[redacted]	[redacted]
Station W	Sandy Lake TS	15,876	[redacted]	[redacted]
Station Y	Keewaywin TS	15,599	[redacted]	[redacted]
Station Z	Sandy Lake SS	14,105	[redacted]	[redacted]
Subtotal RCL Stations		*142,312*	[redacted]	[redacted]

2024 In-Service Asset Additions		**558,195**	[redacted]	[redacted]
			[redacted]	[redacted]
2022/2023 In-Service Assets COVID-19 Cost Additions			[redacted]	[redacted]
Line W54W	230 kV - Dinorwic to Pickle Lake	-	[redacted]	[redacted]
			[redacted]	[redacted]
Line WBC	115 kV - Pickle Lake to Ebane/Pipestone SS	-	[redacted]	[redacted]
Line WCJ	115 kV - Ebane/Pipestone SS to Kingfisher Lake TS	-	[redacted]	[redacted]
Line J1 (25 kV)	25 kV - Kingfisher Lake TS to HORCI Kingfisher Lake	-	[redacted]	[redacted]
Line WCD	115 kV - Ebane/Pipestone SS to North Caribou Lake TS	-	[redacted]	[redacted]
Line WP1P2	115 kV - Red Lake SS to Existing Pikangikum 44 kV Line	-	[redacted]	[redacted]
Line WJK	115 kV - Kingfisher Lake TS to Wawakapewin TS	-	[redacted]	[redacted]
Line WK1 (25kV)	25 kV - Wawakapewin TS to HORCI Wawakapewin	-	[redacted]	[redacted]
Line DE	115 kV - North Caribou Lake TS to Muskrat Dam TS	-	[redacted]	[redacted]
Line E1 (25kV)	25 kV - Muskrat Dam TS to HORCI Muskrat Ram	-	[redacted]	[redacted]
Line EF	115 kV - Muskrat Dam TS to Bearskin Lake TS	-	[redacted]	[redacted]
Line F1 (25kV)	25 kV - Bearskin Lake TS to HORCI Bearskin Lake	-	[redacted]	[redacted]
Line WEG	115 kV - Muskrat Dam TS to Sachigo Lake TS	-	[redacted]	[redacted]
Line WG1 (25kV)	115 kV - Sachigo Lake TS to HORCI Sachigo Lake	-	[redacted]	[redacted]
Line JI	44 kV - Kingfisher TS to Wunnumin TS	-	[redacted]	[redacted]
Line I1 (25kV)	25 kV - Wunnumin TS to HORCI Wunnumin	-	[redacted]	[redacted]
Line KL	44 kV - Wawakapewin TS to Kasabonika TS	-	[redacted]	[redacted]
Line L1 (25kV)	25 kV - Kasabonika TS to HORCI Kasabonika	-	[redacted]	[redacted]
Lines COVID-19 Costs added to 2022/2023 In service Assets		-	[redacted]	[redacted]
			[redacted]	[redacted]
Station A	Wataynikaneyap SS (Dinorwic)	-	[redacted]	[redacted]
Station B	Wataynikaneyap TS (Pickle Lake)	-	[redacted]	[redacted]
			[redacted]	[redacted]
Station C	Ebane/Pipestone SS	-	[redacted]	[redacted]
Station D	North Caribou Lake TS	-	[redacted]	[redacted]
Station J	Kingfisher Lake TS	-	[redacted]	[redacted]
Station P	Red Lake SS	-	[redacted]	[redacted]
Station Q	Pikangikum TS	-	[redacted]	[redacted]
Station E	Muskrat Dam TS	-	[redacted]	[redacted]
Station F	Bearskin Lake TS	-	[redacted]	[redacted]
Station G	Sachigo Lake TS		[redacted]	[redacted]
Station K	Wawakapewin TS	-	[redacted]	[redacted]
Station I	Wunnumin Lake TS	-	[redacted]	[redacted]
Station L	Kasabonika Lake TS	-	[redacted]	[redacted]
Station COVID-19 Costs added to 2022/2023 In service Assets		**-**	[redacted]	[redacted]
Total 2022/2023 In-service Asset COVID-19 Cost Additions		**-**	[redacted]	[redacted]

Line WQR	115 kV - Red Lake TS to Pikangikum Lake TS - Pole Replacement (Sustaining Capital)	-	[redacted]	[redacted]
Total Transmission System In-Service Additions in 2024[4]		**558,195**	**74,570**	**632,995**

The portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at Kitchenuhmaykoosib Inninuwug and Wapekeka First Nation and the portions of the Red Lake Remote Connection Lines that are needed to provide services to HORCI at Poplar Hill First Nation, Deer Lake First Nation, North Spirit Lake First Nation, Sandy Lake First Nation and Keewaywin First Nation are comprised of:

- 6 transformer stations, each with a fenced yard, a control building and a variety of transformation, switching, protection and reactive power compensation equipment, depending on the functionality of the station. The location and functionality of each station is summarized in Table 2.

- 3 switching stations, each with a fenced yard, a control building and a variety of switching, protection and reactive power compensation equipment depending on functionality of the station. The location and functionality of each station is summarized in Table 2.

- 16 overhead line segments, operating at 115 kV or 25 kV, the length, location and functionality of which are summarized in Table 3.

Table 2 – Pickle Lake and Red Lake Remote Connection Lines: 2024 Station In-Service

Station Name	**Location**	**Functionality**
K.I - Wapekeka TS	Approximately 12.3 km East of K.I Airport or 10 km Southwest of Wapekeka First Nation Airport	115 kV to 25 kV transformation to supply both K.I and Wapekeka First Nation; switching for HV and LV equipment; protections for transformers and feeders; reactive power compensation to prevent system over-voltage

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[4] Consistent with prior years, rate base does not include AFUDC in additions as these costs are to be funded by the contribution in aid of construction pursuant to the Federal Funding Framework.

Poplar Hill SS	Approximately 30.5 km East of Poplar Hill First Nation Airport	Switching and protection for incoming/outgoing 115 kV lines; reactive power compensation to prevent system over-voltage
Poplar Hill TS	Approximately 1.0 km East of Poplar Hill First Nation Airport	115 kV to 25 kV transformation to supply Poplar Hill First Nation; switching for HV and LV equipment; protections for transformers and feeders.
Deer Lake SS	Approximately 20.3 km Southeast of Deer Lake First Nation Airport	Switching and protection for incoming/outgoing 115 kV lines; reactive power compensation to prevent system over-voltage
Deer Lake TS	Approximately 1.5 km Southeast of Deer Lake First Nation Airport	115 kV to 25 kV transformation to supply Deer Lake First Nation; switching for HV and LV equipment; protections for transformers and feeders.
North Spirit Lake TS	Approximately 2.0 km Southwest of North Spirit Lake Airport	115 kV to 25 kV transformation to supply North Spirit Lake First Nation; switching for HV and LV equipment; protections for transformers and feeders.
Sandy Lake TS	Approximately 1.2 km West of Sandy Lake First Nation Airport	115 kV to 25 kV transformation to supply Sandy Lake First Nation; switching for HV and LV equipment; protections for transformers and feeders; reactive power compensation to prevent system over-voltage
Keewaywin TS	Approximately 0.6 km East of Keewaywin First Nation Airport	115 kV to 25 kV transformation to supply Keewaywin First Nation; switching for HV and LV equipment; protections for transformers and feeders; reactive power compensation to prevent system over-voltage
Sandy Lake SS	Approximately 57.4 km South of Sandy Lake First Nation Airport or 31.1 km West of North Spirit Lake First Nation Airport	Switching and protection for incoming/outgoing 115 kV lines; reactive power compensation to prevent system over-voltage

Table 3 – Pickle Lake and Red Lake Remote Connection Lines: 2024 Line Segment In-Service Additions

Identifier	Origin	Endpoint	Voltage (kV)	Length (km)
WKM	Wawakapewin TS	Wapakeka/KI TS	115	65.5
WM+	Wapakeka/KI TS	HORCI 25 kV Demarcation	25	0.3
WM-	Wapakeka/KI TS	HORCI 25 kV Demarcation	25	0.3
WQR	Pikangikum TS	Poplar Hill SS	115	42.6
WRS	Poplar Hill SS	Poplar Hill TS	115	32.7

WS1	Poplar Hill TS	HORCI 25 kV Demarcation	25	1.4
WRT	Poplar Hill SS	Deer Lake SS	115	67.9
WTU	Deer Lake SS	Deer Lake TS	115	20.6
WU1	Deer Lake TS	HORCI 25 kV Demarcation	25	0.01
WTZ	Deer Lake SS	Sandy Lake SS	115	27.6
WZW	Sandy Lake SS	Sandy Lake TS	115	96.1
W1	Sandy Lake TS	HORCI 25 kV Demarcation	25	0.3
WZV	Sandy Lake SS	North Spirit TS	115	31.7
WV1	North Spirit TS	HORCI 25 kV Demarcation	25	1.4
WVY	North Spirit TS	Keewaywin TS	115	78.7
WY1	Keewaywin TS	HORCI 25 kV Demarcation	25	0.3

Further to the Transmission System in-service additions described up to this point, general plant in-service additions for 2024 will consist of service centres, operating software, and fleet additions including off-road vehicles, as further discussed in Exhibit B-1-5. Table 4 summarizes WPLP's total in-service additions for 2024.

Table 4 – Total 2024 In-Service Additions

Asset Category	**In-Service Additions ($000's)**
Line to Pickle Lake – Lines	21,910
Line to Pickle Lake – Stations	9,702
Remote Connection Lines – Lines	449,203
Remote Connection Lines – Stations	152,179
General Plant	8,750
Total 2024 In-Service Additions	**641,745**

The in-service additions identified in Table 4 are reasonable as they reflect the EPC contract costs attributable to each of the line segments and stations coming into service, as well as an appropriate allocation of WPLP's non-EPC capital costs, as detailed in **Appendix 'A'**. WPLP's EPC contract procurement process and ongoing oversight, as well as its approach to planning, managing and forecasting non-EPC capital costs, are described in detail in Exhibit B, Tab 1, Schedules 2, 4 and 5, and have been considered by the OEB in the leave to construct proceeding and the initial rates application. The COVID-19 related costs that are included in the in-service additions are identified in Table 1, above, and discussed in Exhibit H.

A. Variance Analysis

As noted in Exhibit A-5-2, the parties to the Settlement Agreement in the initial revenue requirement application (EB-2022-0149) agreed that, in future transmission applications for years in which additional transmission line segments and stations will be placed into service, WPLP will include information on variances for such line segments and stations being placed into service, relative to both the values presented in a prior year application and the values that were presented in the Leave to Construct proceeding (EB-2018-0190). The following provides information on variances relative to those presented in the Leave to Construct proceeding.

The WPLP Leave to Construct application in EB-2018-0190 did not include any general plant, as general plant investments were not subject to the requirement for Leave to Construct and therefore were not considered at that time. As a result, no variance analysis back to the Leave to Construct is provided for general plant compared to the amount being placed in-service in the 2024 test year.

Based on the unit costing WPLP used to complete the Leave to Construct application in EB-2018-0190, total costs for lines ($244 million) and substations ($77 million) included in the Leave to Construct for the 2024 in-service assets were $321 million, for a variance of $320 million (including general plant) when compared to the $642 million in-service assets included in Table 4 above. The drivers of this variance between the costs presented in the Leave to Construct application and the costs of the in-service asset additions related to the Remote Connection Lines in 2024 are provided in EB-2021-0134 in Exhibit B-1-5. The drivers outlined in EB-2021-0134 are the same drivers for the specific substations and line segments that are going in-service in this application. In addition to the variances described in EB-2021-0134, the 2024 in-service additions sought in this application have increased by the following Change Orders and other costs related to COVID-19,[5] 2021 forest fire and MNRF fire prevention order impacts and scope changes which are the subject of commercial discussions with the EPC contractor, and which are set out in Table 5 below.

Table 5 – 2024 In-Service Asset Reconciliation ($000)

	Transmission Lines	**Substations**	**Total**
Leave to Construct – Asset Value	244,097	77,302	321,399
Change based on EPC Contract Execution	115,637	42,220	157,857
Non-EPC Cost Allocation[6]	48,778	16,207	64,985
Change Orders			
[redacted]	[redacted]	[redacted]	[redacted]
Changes to Routing	403	-	403
Change to Design Requirements	126	312	438
[redacted]	[redacted]	[redacted]	[redacted]
Additional Scope	460	2,012	2,473
	[redacted]	[redacted]	[redacted]
Sustaining capital	230	-	230
General Plant Additions	-	-	8,750
Total 2024 In-Service Additions	**471,113**	**161,881**	**641,745**

There are two main drivers for the variance between the values in the Leave to Construct application and the forecasted in-service additions for the Remote Connection Lines: (1) executed EPC contract (described in Exhibit B-1-5 in EB-2021-0134) and (2) executed EPC change orders and other costs (described below).

As of December 31, 2022, WPLP has executed change orders and other anticipated costs, the majority of which relate to COVID-19, design changes, routing changes, and 2021 forest fire/MNRF fire prevention order impacts that are the subject of commercial discussions with the EPC contractor. These change orders and other anticipated costs represent additional forecasted

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[5] Does not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account or in the 2021-2023 CCCDA (as proposed to be amended) upon the conclusion of the commercial discussions between WPLP and its EPC contractor.

[6] Details of non-EPC cost allocation to capital project provided in Exhibit B-1-5.

costs of approximately $88.5 million. Regarding the change orders noted in Table 5 above (which include other anticipated costs), 2 change orders exceed application materiality, not including the COVID-19 related costs of $74.6 million[7] which are described in Exhibit H-2-2. [redacted]

Variance analysis between approved and forecasted 2022 in-service additions for the Line to Pickle Lake and Remote Connection Lines are summarized in Table 6 and Table 8 respectively.

Table 6 – 2023 Line to Pickle Lake In-Service Addition Variance ($000)[10]

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**		**Variance**
	2023 Rate Application	**Forecast**	
1715 - Station Equipment (Station and Transformers)	32,696	45,810	10,114
1715A - Station Equipment (Switches and Breakers)	6,241	6,278	37
1715B - Station Equipment (Protection and Control)	1,493	1,498	5
1720 - Towers and Fixtures	113,069	114,704	1,635
1725 - Poles and Fixtures	0	0	0
1730 - OH Conductor and Devices	133,750	154,025	20,275
Total	**290,249**	**322,315**	**32,066**

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[7] These costs are or will be recorded in the 2021-2023 CCCDA until transfer to CWIP Account 2055, as proposed in Exhibit H.

[8] [redacted]

[redacted]

[10] In the WPLP Leave to Construct proceeding WPLP forecasted the Line to Pickle Lake costs before interest and [redacted], detailed in Exhibit H-2-2, and other scope change orders.

The main driver for the variance between 2023 OEB approved and 2023 forecasted in-service addition values for the Line to Pickle Lake are the executed or pending EPC change orders.

As of April 30, 2023, WPLP has executed/pending change orders, the majority relating to COVID-19 costs, and additional scope. These change orders represent additional forecasted costs of approximately $32 million. Further details on change order costs are provided in Table 7 below.

Table 7 – Line to Pickle Lake Change Orders

	($000)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
	32,066

Regarding the change orders noted in Table 7 above, the COVID-19 executed and pending change orders are the main drivers of the forecasted changes to the Line to Pickle Lake in-service value. Further details on COVID-19 costs are detailed in Exhibit H-2-2.

In relation to Remote Connection Lines, there are two main drivers for the variance between OEB approved and forecasted in-service additions for the Remote Connection Lines in 2023: (1) executed or pending EPC change orders, and (2) acceleration of the construction schedule which moved the in-service dates for lines WEG and WG1, as well as substation G, to November 2023.

Table 8 – 2022/2023 Remote Connection Lines In-Service Addition Variance ($000)

OEB Account and Description	**Remote Connection Lines (H1RCI Rate)**		**Variance**
	2023 Rate Application[11]	**Forecast**	

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[11] Balances from 2023 year-end for Remote Connection lines provided in 2023 rate application in Exhibit C-3-1, Table 3 (EB-2022-0149).

1715 - Station Equipment (Station and Transformers)	161,415	187,966	26,551
1715A - Station Equipment (Switches and Breakers)	13,959	14,863	904
1715B - Station Equipment (Protection and Control)	6,776	7,540	764
1720 - Towers and Fixtures	241,411	273,449	32,038
1725 - Poles and Fixtures	32,786	33,581	795
1730 - OH Conductor and Devices	282,942	333,526	50,584
Total	**739,289**	**850,925**	**111,636**

As of April 30, 2023, WPLP has 15 executed or pending Change Orders, in addition to the ones noted in the 2023 rate application, the majority relating to routing changes, COVID-19, additional scope and 2021 forest fire/MNRF fire prevention order impacts.[12] These executed and pending Change Orders represent additional forecasted costs of approximately [redacted]. Further details on change order costs are provided in Table 9, below.

Table 9 – Remote Connection Lines Changes

	($000)
Transmission Line Change Orders	
Changes to Routing	702
[redacted]	[redacted]
[redacted]	[redacted]
Additional Scope	375
Substation Change Orders	
[redacted]	[redacted]
Additional Scope	682
[redacted]	[redacted]
	[redacted]
Change in Construction Schedule[13]	
Line WEG	58,712
Line WG1	2,075
Substation G	19,430

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[12] The cost impacts of the 2021 forest fires and MNRF fire prevention orders are not yet known as WPLP and Valard are engaged in ongoing commercial discussions.

[13] This represents the CWIP costs for Sachigo Lake segment transmission assets which are planned to come into service in November 2023, as compared to the prior expected in-service date of May 2024.

	80,217
Total Variance	[redacted]

Regarding the change orders noted in Table 9 above excluding COVID, 2 individual change orders exceed application materiality. The first relates to a routing change for Muskrat Dam First Nation that was settled for $1 million higher than forecasted in the 2023 rate application. The second change order relates to forest fires that occurred during the 2021 summer construction season. The forest fires, along with MNRF fire prevention orders, shut down all construction on the Project for an approximate six-week period.

Variance analysis between overall capital cost estimates presented in EB-2021-0134 and WPLP's current capital cost estimates (excluding impacts of the COVID-19 pandemic, which are addressed in Exhibit H-2-2) are provided in Exhibit B-1-5. Fixed asset continuity and depreciation schedules are provided in Exhibit C-3-1.

Appendix ‘A’

Capital Cost Allocation to Fixed Asset Accounts

Appendix ‘A’

Capital Cost Allocation to Fixed Asset Accounts

The capital costs outlined in Exhibit B-1-5 include several categories of costs:

- **EPC Contract Costs:** EPC costs that include costs directly attributable to individual line segments and substations (based on the breakdown provided in the EPC bid) as well as general EPC costs that were pro-rated to individual line segments and substations.

- **Non-EPC Capital Costs:** Estimated costs of (i) certain discrete capital costs that were excluded from the EPC contract scope and costs related to general plant investments, (collectively “EPC Excluded Costs”) and (ii) other non-EPC capital costs that WPLP has incurred or expects to incur over the project period that are clearly and directly related to the Transmission Project and are therefore clearly capital in nature (“Non-EPC Attributed to Capital”).

- **Overhead Costs:** The portion of WPLP’s overhead costs that are forecasted to be capitalized, based on the methodology described in Appendix ‘A’ of Exhibit B-1-5.

Pursuant to the settlement agreements in EB-2021-0134 and EB-2022-0149, WPLP agreed to remove and defer the forecasted contingency amounts from its in-service year-end rate bases for 2022 and 2023. WPLP also agreed to establish a new deferral account to track the revenue requirement impacts associated with the amounts of contingency allocated to 2022 and 2023 in-service additions, to the extent that such contingencies are realized and do not exceed the amounts removed from rate base. In the current Application, WPLP is proposing to continue to use this approach and, as a result, has not included any of the $81.9 million of contingency costs associated with the 2024 in-service additions.

This Appendix ‘A’ describes how the capital costs in the categories listed above are assigned to WPLP’s various fixed asset accounts for the purpose of determining its 2024 in-service additions.

Table A-1 below provides a breakdown of the forecasted capital cost (before AFUDC), according to whether or not the costs are directly attributable to fixed assets.

Table A-1 – Summary of Total Direct and Allocated Capital Costs

Cost Category	Allocation of Capital Costs ($000's)			
	Direct to Fixed Assets	**Allocate Proportional to EPC Costs**	**Excluded from In-Service additions**	**Total**
EPC Costs	1,419,979	12,800	0	1,432,779
EPC Excluded Costs	9,245	10,012	0	19,257
Non-EPC Attributed to Capital	0	121,757	0	121,757
Capitalized Overhead Costs	0	70,663	0	70,663
Change Orders (Executed and under discussion)	[redacted]	0	0	[redacted]
COVID-19 Costs	74,570	0	0	74,570
Contingency	[redacted]	0	81,882	81,882
Total	[redacted]	**215,232**	**81,882**	[redacted]
Less costs allocated to in-service assets: 2022 Allocated Portion		-92,493		
2023 Allocated Portion		-57,754		
Total costs to be allocated to 2024 In-Service Assets		**64,985**		

WPLP expects to transfer approximately $1,420 million of base EPC contract costs from CWIP to specific fixed asset accounts, based on breakdowns provided in the EPC bid schedules. EPC excluded costs of approximately $9.2 million relating to fleet, facilities and business systems, plus [redacted] for Change Orders, are also directly attributable to specific fixed asset accounts. In addition, $74.6 million has been added for COVID-19 costs[15] directly attributable to specific fixed asset accounts.

The remaining approximately $215 million of WPLP's forecasted capital project costs relate to general costs that are not directly attributable to specific fixed asset accounts. These costs include items such as contract security, insurance, project development[16] and project management costs, and capitalized overhead costs. In order to clear these costs from CWIP to rate base, the costs already allocated to assets in 2022 and 2023 are removed leaving the remaining costs of $65 million, to be allocated as WPLP's assets come into service, WPLP proposes to pro-rate these

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[14] [redacted]

[15] COVID-19 costs transferred to CWIP as discussed in Exhibit H-2-1.

[16] These costs were initially recorded in WPLP's Development Cost Deferral Account, and subsequently transferred into the CWIP account, pursuant to the OEB's decision in EB-2018-0190.

costs in proportion to the base EPC contract costs remaining to come in to service in 2024 of $548.6 million, as each station or line segment comes into service. Table A-2 below illustrates the proportional allocation for assets that are scheduled to go into service in 2024.

Table A-2 – Proportional Allocation for 2024 In-Service Additions ($000's)

Asset Designation	**EPC Base Amount**	**% of EPC Costs**	**Proportional Allocation of General Capital Costs**	**Change Orders**	**Additions to Fixed Asset Accounts**
	A	**B = A / 479,257**	**C = B * 64,985**	**D**	**E = A + C + D**
Line WKM	38,996	8.14%	5,288	[redacted]	[redacted]
Line WM+ (25kV)	146	0.03%	20	[redacted]	[redacted]
Line WM- (25kV)	535	0.11%	73	[redacted]	[redacted]
Line WQR	35,079	7.32%	4,757	[redacted]	[redacted]
Line WRS	23,283	4.86%	3,157	[redacted]	[redacted]
Line WS1 (25kV)	1,607	0.34%	218	[redacted]	[redacted]
Line WRT	67,718	14.13%	9,182	[redacted]	[redacted]
Line WTU	20,746	4.33%	2,813	[redacted]	[redacted]
Line U1 (25kV)	137	0.03%	19	[redacted]	[redacted]
Line WTZ	21,702	4.53%	2,943	[redacted]	[redacted]
Line WZW	68,854	14.37%	9,336	[redacted]	[redacted]
Line W1 (25kV)	231	0.05%	31	[redacted]	[redacted]
Line WZV	22,430	4.68%	3,041	[redacted]	[redacted]
Line WV1 (25kV)	565	0.12%	77	[redacted]	[redacted]
Line WVY	57,066	11.91%	7,738	[redacted]	[redacted]
Line WY1 (25kV)	639	0.13%	87	[redacted]	[redacted]
Station M	16,350	3.41%	2,217	[redacted]	[redacted]
Station R	11,197	2.34%	1,518	[redacted]	[redacted]
Station S	11,961	2.50%	1,622	[redacted]	[redacted]
Station T	10,688	2.23%	1,449	[redacted]	[redacted]
Station U	11,533	2.41%	1,564	[redacted]	[redacted]
Station V	18,989	3.96%	2,575	[redacted]	[redacted]
Station W	13,858	2.89%	1,879	[redacted]	[redacted]
Station Y	13,614	2.84%	1,846	[redacted]	[redacted]
Station Z	11,332	2.36%	1,537	[redacted]	[redacted]
Total	**479,257**	**100%**	**64,985**	[redacted]	[redacted]

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[17] Agrees to 2024 in-service asset additions in Table 1 above.

Appendix 'B'

WPLP 2024 In Service Forecast Map

ᐊ·ᑌᓂᑲᓂᔭᑊ Wataynikaneyap Power

WATAYNIKANEYAP POWER
In Service Forecast by Year

0 10 20 40 60 80 100
km

● Wataynikaneyap Power Community
○ First Nation Community
● Town
A Substation
— Existing Arterial Road/Highway
- - - - Existing Winter Road

In Service Date
🟥 2022
🟨 2023
🟦 2024

🟫 First Nation Reserve
🟩 Provincial Park
🟩 Dedicated Protected Area - Far North
🟦 Waterbody

REFERENCE:
Transmission Routes - Provided by Wataynikaneyap Power
First Nation Reserve Communities, Waterbodies, Provincial Parks, Existing Roads - Land Information Ontario (https://geohub.lio.gov.on.ca/datasets)
Coordinate System - NAD 1983 CSRS UTM Zone 15N
Map Updated: 2023-06-01

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KBM RESOURCES GROUP

Exhibit C, Tab 3, Schedule 1

Gross Assets – Property, Plant & Equipment and Accumulated Depreciation

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND ACCUMULATED DEPRECIATION

As discussed in Exhibit B-1-1, during 2022 WPLP put into service the entirety of the Line to Pickle Lake including its 2 associated substations, and for the Remote Connection Lines, WPLP put into service 4 of the 20 substations and 5 of the 34 line segments. In 2023, WPLP plans to put into service 7 of the 16 remaining substations and 14 of the 29 remaining line segments[1], as well as to convert the Pikangikum Distribution System to form part of the Transmission System. Table 1 provides the approved, forecasted and resulting variance for the 2023 in-service asset additions.[2] Table 2 provides the approved, forecasted and resulting variance for the 2023 depreciation[3]. The forecasted balances from Tables 1 and 2 are used to determine WPLP's resulting opening balances for 2024 gross assets and accumulated depreciation, which are set out in Tables 6 and 7, below.

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[1] These counts include line segments and substations associated with the Pikangikum Distribution System that are already in service and transitioned to a transmission supply on May 12, 2023.

[2] Forecasted balances reflect forecasted capital spend and in-services dates, variance analysis is provided in Exhibit C-2-1.

[3] Forecasted balances reflect forecasted capital spend and in-services dates, depreciation has been adjusted based on the updated forecasted capital spend and in-services dates utilizing the same depreciation methodology as discussed in Exhibit F-4-1.

Table 1 - 2023 Year-End Gross Assets by OEB Account ($000's)

	2023 Rate Application			Forecast			
OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Variance**
1715 - Station Equipment (Station and Transformers)	35,696	161,415	197,111	36,108	180,660	216,768	19,657
1715A - Station Equipment (Switches and Breakers)	6,241	13,959	20,201	6,278	14,863	21,140	939
1715B - Station Equipment (Protection and Control)	1,493	6,776	8,269	1,498	7,540	9,039	770
1720 - Towers and Fixtures	113,069	241,411	354,480	113,069	269,931	383,000	28,520
1725 - Poles and Fixtures	0	32,786	32,786	-	33,494	33,494	708
1730 - OH Conductor and Devices	133,750	282,942	416,692	133,750	316,377	450,127	33,436
Sub-Total Transmission System Plant	**290,249**	**739,290**	**1,029,539**	**290,703**	**822,866**	**1,113,568**	**84,030**
1908 - Buildings and Fixtures[4]	1,693	3,307	5,000	0	0	0	-5,000
1915 - Office Furniture and Equipment	51	100	151	14	26	40	-111
1930 - Transportation Equipment	91	179	270	52	103	155	-115
1611 - Computer Software	169	331	500	101	199	300	-200
Total	**292,254**	**743,207**	**1,035,460**	**290,870**	**823,194**	**1,114,064**	**78,604**

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[4] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant assets.

Table 2 – 2023 Year-End Accumulated Depreciation by OEB Account ($000's)

	2023Rate Application			Forecast			
OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Variance**
1715 – Station Equipment (Station and Transformers)	952	2,542	3,494	961	2,365	3,325	169
1715A – Station Equipment (Switches and Breakers)	208	299	508	208	271	479	28
1715B – Station Equipment (Protection and Control)	100	272	371	100	251	351	20
1720 – Towers and Fixtures	2,513	3,835	6,348	2,510	3,467	5,977	371
1725 – Poles and Fixtures	-	384	384	-	370	370	14
1730 – OH Conductor and Devices	3,963	5,976	9,939	3,966	5,497	9,463	476
Sub-Total Transmission System Plant	**7,735**	**13,308**	**21,043**	**7,745**	**12,220**	**19,965**	**1,078**
1908 – Buildings and Fixtures[5]–	6	11	17	0	0	0	17
1915 – Office Furniture and Equipment	1	1	2	1	1	2	0
1930 – Transportation Equipment	25	50	75	16	31	47	29
1611 – Computer Software	31	61	92	3	7	10	82
Total	**7,798**	**13,431**	**21,229**	**7,765**	**12,259**	**20,024**	**1,205**

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[5] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant assets.

Table 3, below, summarizes WPLP's forecasted year-end gross assets for the 2024 test year, by OEB account and by rate pool, which are consistent with the in-service additions described in detail in Exhibit C-2-1.

Table 3 – 2024 Year-End Gross Assets by OEB Account ($000's)

OEB Account and Description	Line to Pickle Lake (UTR Network Rate)	Remote Connection Lines (HORCI Rate)	Total
1715 – Station Equipment (Station and Transformers)	45,902	316,791	362,693
1715A – Station Equipment (Switches and Breakers)	6,193	25,067	31,260
1715B – Station Equipment (Protection and Control)	1,491	13,384	14,875
1720 – Towers and Fixtures	114,243	498,786	613,029
1725 – Poles and Fixtures	0	35,518	35,518
1730 – OH Conductor and Devices	154,486	534,701	689,187
Sub-Total Transmission System Plant	**322,315**	**1,424,248**	**1,746,563**
1908 – Buildings and Fixtures	1,056	3,944	5,000
1915 – Office Furniture and Equipment	25	95	120
1930 – Transportation Equipment[6]	174	651	825
1611 – Computer Software	697	2,603	3,300
Total	**324,268**	**1,431,540**	**1,755,808**

Table 4 summarizes WPLP's accumulated depreciation by OEB Account and by rate pool for the 2024 test year. Exhibit F-4-1 provides further detail on the calculation of depreciation expense.

Table 4 – 2024 Year-End Accumulated Depreciation by OEB Account ($000's)

OEB Account and Description	Line to Pickle Lake (UTR Network Rate)	Remote Connection Lines (HORCI Rate)	Total
1715 – Station Equipment (Station and Transformers)	1,861	7,494	9,354
1715A – Station Equipment (Switches and Breakers)	365	781	1,146

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[6] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

1715B – Station Equipment (Protection and Control)	175	784	958
1720 – Towers and Fixtures	4,420	10,038	14,458
1725 – Poles and Fixtures	0	1,137	1,137
1730 – OH Conductor and Devices	7,352	15,257	22,608
Sub-Total Transmission System Plant	**14,171**	**35,491**	**49,662**
1908 – Buildings and Fixtures	4	13	17
1915 – Office Furniture and Equipment	2	9	12
1930 – Transportation Equipment[7]	31	116	147
1611 – Computer Software	131	489	620
Total	**14,339**	**36,117**	**50,457**

A. Treatment of Pikangikum Distribution System Assets

As detailed in Exhibit H-1-1, WPLP's Pikangikum Distribution System was placed in service in December 2018. WPLP's costs related to that system after that in-service date were recorded in the Pikangikum Distribution System Deferral Account until that system was transferred to a transmission supply on May 12, 2023, following which the relevant assets form part of WPLP's transmission system. Since these assets were previously distribution assets, they were not included in the opening values presented in WPLP's fixed asset continuity schedules. Further, because the initial capital costs for constructing these assets were funded by Indigenous and Northern Affairs Canada ("INAC", now Indigenous Services Canada), the capital contribution offset the fixed asset value, effectively resulting in zero rate base. Since there was no rate base or revenue requirement impact related to the initial capital costs for these assets, WPLP excluded these assets from its fixed asset continuity schedule in its application for approval of its 2023 revenue requirement consistent with the approach in its initial rate application in EB-2021-0134. WPLP intends to add these assets to its fixed asset continuity schedule in its 2024 application for approval of its 2025 test year revenue requirement. In that application, WPLP intends to revert to the half-year rule approach to calculating rate base and depreciation expense, and WPLP will also address both the

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[7] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

initial capital contribution from INAC/ISC towards the construction of the Pikangikum system, and any capital contribution resulting from the federal funding framework discussed in I-4-1.

B. Average Values for Rate Base Determination

In its prior rate applications, considering the differences in timing and cost recovery[8], WPLP proposed (and the OEB accepted) the use of 12-month averages of gross assets and accumulated depreciation for the determination of net fixed assets included in rate base. In WPLP's view, this method remains appropriate and is therefore proposed for the 2024 test year because it continues to apportion WPLP's revenue requirement more accurately between the parties that distinctly benefit from each group of assets as the Remote Connection Lines continue to come into service[9]. Table 5 summarizes WPLP's 2024 average net fixed assets using this approach. As noted in C-1-1, WPLP plans on using the 12-month average approach in 2024 even with minor sustaining capital additions and to convert to the half-year rule once all assets are in service.

Table 5 – Summary of 2024 Average Net Fixed Assets

Item	**2024 12-Month Average ($000's)**			
	LTPL	**RCL**	**GP**	**Total**
Gross Fixed Assets	320,998	1,180,567	4,844	1,506,409
Less Accumulated Depreciation	-10,932	-22,490	-380	-33,803
Net Fixed Assets	**310,066**	**1,158,076**	**4,464**	**1,472,606**

Monthly totals of WPLP's gross asset and accumulated depreciation balances supporting the 12-month average calculation are provided in Tables 6 and 7. Fixed asset continuity schedules reflecting all in-service additions for the 2024 test year are included as Appendix 'A' to this schedule.

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[8] Cost recovery for the Line to Pickle Lake is through the UTR Network rate, whereas cost recovery for the Remote Connection Lines is directly from HORCI. See Exhibit I.

[9] The Network pool receives the full benefit from the Line to Pickle Lake coming into service in early to Mid-August 2022, whereas HORCI benefits to varying degrees as additional portions of the Remote Connection Lines come into service.

Table 6 – 2024 Gross Asset Balances by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	290,703	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	
	Additions	31,613	0	0	0	0	0	0	0	0	0	0	0	
	Closing	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	
	Average	306,509	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	322,315	320,998
RCL	Opening	822,866	850,925	850,925	850,925	1,012,728	1,148,883	1,289,277	1,342,590	1,424,248	1,424,248	1,424,248	1,424,248	
	Additions	28,059	0	0	161,803	136,155	140,394	53,313	81,658	0	0	0	0	
	Closing	850,925	850,925	850,925	1,012,728	1,148,883	1,289,277	1,342,590	1,424,248	1,424,248	1,424,248	1,424,248	1,424,248	
	Average	836,895	850,925	850,925	931,826	1,080,805	1,219,080	1,315,933	1,383,419	1,424,248	1,424,248	1,424,248	1,424,248	1,180,567
GP	Opening	495	3,535	3,535	3,535	3,645	3,645	4,135	4,245	4,245	4,245	9,245	9,245	
	Additions	3,040	0	0	110	0	490	110	0	0	5,000	0	0	
	Closing	3,535	3,535	3,535	3,645	3,645	4,135	4,245	4,245	4,245	9,245	9,245	9,245	
	Average	2,015	3,535	3,535	3,590	3,645	3,890	4,190	4,245	4,245	6,745	9,245	9,245	4,844

Table 7 – 2024 Accumulated Depreciation by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	7,745	8,229	8,769	9,310	9,850	10,390	10,930	11,470	12,011	12,551	13,091	13,631	
	Additions	484	540	540	540	540	540	540	540	540	540	540	540	
	Closing	8,229	8,769	9,310	9,850	10,390	10,930	11,470	12,011	12,551	13,091	13,631	14,171	
	Average	7,987	8,499	9,039	9,580	10,120	10,660	11,200	11,740	12,281	12,821	13,361	13,901	10,932
RCL	Opening	12,220	13,607	15,042	16,477	17,912	19,618	21,546	23,705	25,954	28,338	30,722	33,106	
	Additions	1,386	1,435	1,435	1,435	1,706	1,928	2,159	2,249	2,384	2,384	2,384	2,384	
	Closing	13,607	15,042	16,477	17,912	19,618	21,546	23,705	25,954	28,338	30,722	33,106	35,491	
	Average	12,913	14,324	15,759	17,195	18,765	20,582	22,625	24,829	27,146	29,530	31,914	34,298	22,490
GP	Opening	59	67	125	183	241	301	361	429	499	569	639	717	
	Additions	8	58	58	58	60	60	68	70	70	70	78	78	
	Closing	67	125	183	241	301	361	429	499	569	639	717	795	
	Average	63	96	154	212	271	331	395	464	534	604	678	756	380

APPENDIX ‘A’

Fixed Asset and Depreciation Continuity

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2022

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	-	-	-	-	-	-	-
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-	-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	-	100,306,884	-	100,306,884	50	-	429,999	-	429,999	99,876,885
47	1715A	Station Equipment (Switches and Breakers)	-	12,772,222	-	12,772,222	40	-	77,638	-	77,638	12,694,585
47	1715B	Station Equipment (Protection and Control)	-	4,360,015	-	4,360,015	20	-	45,558	-	45,558	4,314,457
47	1720	Towers and Fixtures	-	255,216,234	-	255,216,234	60	-	974,572	-	974,572	254,241,662
47	1725	Poles and Fixtures	-	1,727,765	-	1,727,765	45	-	4,123	-	4,123	1,723,641
47	1730	OH Cond and Devices	-	304,804,364	-	304,804,364	45	-	1,557,034	-	1,557,034	303,247,330
	1735	UG Conduit	-	-	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-	-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	50	-	-	-	-	-
8	1915	Office Furn & Equipment	-	-	-	-	10	-	-	-	-	-
	1920	Comp Hardware	-	-	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	-	155,392	-	155,392	5	-	15,539	-	15,539	139,853
	1935	Stores Equip	-	-	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-
		Sub-Total	-	**679,342,875**	-	**679,342,875**		-	**3,104,462**	-	**3,104,462**	**676,238,413**
	2055	**Add: Construction Work in Progress**	889,733,555	392,413,313	(679,342,875)	602,803,992		-	-	-	-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)			-	-		-	-	-	-	
		Total PP&E	889,733,555	1,071,756,188	(679,342,875)	1,282,146,868		-	3,104,462	-	3,104,462	676,238,413
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							3,104,462			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**	
Transportation	
Stores Equipment	
Net Depreciation	**3,104,462**

Calculation of Depreciation Expense - All Assets

Accounting Standard	ASPE
Year	2022

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
Intangible			*A*	*B*	*C = A - B*	*D*	*E = C + D/2*	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	-	-	-	-	-
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
Transmission Plant			*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	-	-	-	100,306,884	21,499,930	50	2.00%	429,999
47	1715A	Station Equipment (Switches and Breakers)	-	-	-	12,772,222	3,105,506	40	2.50%	77,638
47	1715B	Station Equipment (Protection and Control)	-	-	-	4,360,015	911,153	20	5.00%	45,558
47	1720	Towers and Fixtures	-	-	-	255,216,234	58,474,318	60	1.67%	974,572
47	1725	Poles and Fixtures	-	-	-	1,727,765	185,552	45	2.22%	4,123
47	1730	OH Cond and Devices	-	-	-	304,804,364	70,066,527	45	2.22%	1,557,034
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
General Plant			*A*	*B*	*C = A - B*	*D*	*E = C + D*8/12*	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	-	50	2.00%	-
8	1915	Office Furn & Equipment	-	-	-	-	-	10	10.00%	-
	1920	Comp Hardware	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	-	-	-	155,392	77,696	5	20.00%	15,539
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**-**	**-**	**-**	**679,342,875**	**154,320,681**			**3,104,462**

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard ASPE
Year 2022

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-			-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-			-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-			-		-	-
	1710	Leasehold Improvements	-	-	-	-			-		-	-
47	1715	Station Equipment (Station and Transformers)	-	35,850,038	-	35,850,038	50		239,000		239,000	35,611,038
47	1715A	Station Equipment (Switches and Breakers)	-	6,156,918	-	6,156,918	40		51,308		51,308	6,105,610
47	1715B	Station Equipment (Protection and Control)	-	1,485,731	-	1,485,731	20		24,762		24,762	1,460,969
47	1720	Towers and Fixtures	-	112,607,525	-	112,607,525	60		625,597		625,597	111,981,928
47	1725	Poles and Fixtures	-	-	-	-			-		-	-
47	1730	OH Cond and Devices	-	134,211,114	-	134,211,114	45		994,156		994,156	133,216,958
	1735	UG Conduit	-	-	-	-			-		-	-
	1740	UG Cond and Devices	-	-	-	-			-		-	-
	1745	Roads and Trails	-	-	-	-			-		-	-
		Sub-Total	**-**	**290,311,326**	**-**	**290,311,326**		**-**	**1,934,824**	**-**	**1,934,824**	**288,376,502**
	2055	**Add: Construction Work in Progress**				-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)				-					-	
		Total PP&E	-	290,311,326	-	290,311,326		-	1,934,824	-	1,934,824	288,376,502
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							1,934,824			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**1,934,824**

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard ASPE
Year 2022

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	-	-	-	35,850,038	11,950,013	50	2.00%	239,000
47	1715A	Station Equipment (Switches and Breakers)	-	-	-	6,156,918	2,052,306	40	2.50%	51,308
47	1715B	Station Equipment (Protection and Control)	-	-	-	1,485,731	495,244	20	5.00%	24,762
47	1720	Towers and Fixtures	-	-	-	112,607,525	37,535,842	60	1.67%	625,597
47	1725	Poles and Fixtures	-	-	-	-	-	-	-	-
47	1730	OH Cond and Devices	-	-	-	134,211,114	44,737,038	45	2.22%	994,156
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**-**	**-**	**-**	**290,311,326**	**96,770,443**			**1,934,824**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2022

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-			-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-			-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-			-		-	-
	1710	Leasehold Improvements	-	-	-	-			-		-	-
47	1715	Station Equipment (Station and Transformers)	-	64,456,846	-	64,456,846	50		190,998		190,998	64,265,847
47	1715A	Station Equipment (Switches and Breakers)	-	6,615,305	-	6,615,305	40		26,330		26,330	6,588,975
47	1715B	Station Equipment (Protection and Control)	-	2,874,284	-	2,874,284	20		20,795		20,795	2,853,488
47	1720	Towers and Fixtures	-	142,608,709	-	142,608,709	60		348,975		348,975	142,259,734
47	1725	Poles and Fixtures	-	1,727,765	-	1,727,765	45		4,123		4,123	1,723,641
47	1730	OH Cond and Devices	-	170,593,250	-	170,593,250	45		562,878		562,878	170,030,372
	1735	UG Conduit	-	-	-	-			-		-	-
	1740	UG Cond and Devices	-	-	-	-			-		-	-
	1745	Roads and Trails	-	-	-	-			-		-	-
		Sub-Total	**-**	**388,876,158**	**-**	**388,876,158**		**-**	**1,154,099**	**-**	**1,154,099**	**387,722,058**
	2055	**Add: Construction Work in Progress**				-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)				-					-	
		Total PP&E	-	388,876,158	-	388,876,158		-	1,154,099	-	1,154,099	387,722,058
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							1,154,099			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**1,154,099**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard ASPE
Year 2022

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	A	B	C = A - B	D	E = Avg Monthly Opening	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	-	-	-	64,456,846	9,549,917	50	2.00%	190,998
47	1715A	Station Equipment (Switches and Breakers)	-	-	-	6,615,305	1,053,200	40	2.50%	26,330
47	1715B	Station Equipment (Protection and Control)	-	-	-	2,874,284	415,909	20	5.00%	20,795
47	1720	Towers and Fixtures	-	-	-	142,608,709	20,938,475	60	1.67%	348,975
47	1725	Poles and Fixtures	-	-	-	1,727,765	185,552	45	2.22%	4,123
47	1730	OH Cond and Devices	-	-	-	170,593,250	25,329,489	45	2.22%	562,878
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**-**	**-**	**-**	**388,876,158**	**57,472,543**			**1,154,099**

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2023

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	-	300,000	-	300,000	5	-	10,000		10,000	290,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	100,306,884	116,547,496	-	216,854,379	50	429,999	2,895,340		3,325,339	213,529,040
47	1715A	Station Equipment (Switches and Breakers)	12,772,222	8,298,837	-	21,071,060	40	77,638	401,598		479,236	20,591,824
47	1715B	Station Equipment (Protection and Control)	4,360,015	4,661,688	-	9,021,703	20	45,558	305,296		350,853	8,670,849
47	1720	Towers and Fixtures	255,216,234	126,240,734	-	381,456,968	60	974,572	5,002,332		5,976,904	375,480,064
47	1725	Poles and Fixtures	1,727,765	31,766,200	-	33,493,965	45	4,123	365,662		369,785	33,124,180
47	1730	OH Cond and Devices	304,804,364	146,865,837	-	451,670,202	45	1,557,034	7,905,959		9,462,993	442,207,208
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	50	-	-		-	-
8	1915	Office Furn & Equipment	-	40,000	-	40,000	10	-	2,000		2,000	38,000
	1920	Comp Hardware	-	-	-	-	-	-	-		-	-
10.1	1930	Transportation Equipment	155,392	-	-	155,392	5	15,539	31,078		46,617	108,774
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-		-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-		-		-	-
	1950	Power Operated Equipment	-	-	-	-	-		-		-	-
	1955	Communication Equipment	-	-	-	-	-		-		-	-
	1960	Misc. Equipment	-	-	-	-	-		-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-		-		-	-
	1995	Contributions & Grants	-	-	-	-	-		-		-	-
	2440	Deferred Revenue	-	-	-	-	-		-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**679,342,875**	**434,720,792**	**-**	**1,114,063,668**		**3,104,462**	**16,919,265**	**-**	**20,023,728**	**1,094,039,940**
	2055	**Add: Construction Work in Progress**	602,803,992	469,449,125	(434,720,792)	637,532,325					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,282,146,868	904,169,918	(434,720,792)	1,751,595,993		3,104,462	16,919,265	-	20,023,728	1,094,039,940
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							16,919,265			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**	
Transportation	
Stores Equipment	
Net Depreciation	**16,919,265**

Calculation of Depreciation Expense - All Assets

Accounting Standard	ASPE
Year	2023

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Intangible	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	300,000	50,000	5	20.00%	10,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	100,306,884	-	100,306,884	116,547,496	144,858,455	50	2.00%	2,895,340
47	1715A	Station Equipment (Switches and Breakers)	12,772,222	-	12,772,222	8,298,837	15,979,359	40	2.50%	401,598
47	1715B	Station Equipment (Protection and Control)	4,360,015	-	4,360,015	4,661,688	6,099,020	20	5.00%	305,296
47	1720	Towers and Fixtures	255,216,234	-	255,216,234	126,240,734	299,678,872	60	1.67%	5,002,332
47	1725	Poles and Fixtures	1,727,765	-	1,727,765	31,766,200	16,454,777	45	2.22%	365,662
47	1730	OH Cond and Devices	304,804,364	-	304,804,364	146,865,837	356,229,239	45	2.22%	7,905,959
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		General Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	833,333	50	2.00%	-
8	1915	Office Furn & Equipment	-	-	-	40,000	20,000	10	10.00%	2,000
	1920	Comp Hardware	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	155,392	-	155,392	-	155,391	5	20.00%	31,078
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**679,342,875**	**-**	**679,342,875**	**434,720,792**	**840,358,447**			**16,919,265**

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard	ASPE
Year	2023

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	35,850,038	349,381	-	36,199,418	50	239,000	721,577		960,577	35,238,841
47	1715A	Station Equipment (Switches and Breakers)	6,156,918	36,216	-	6,193,134	40	51,308	156,867		208,174	5,984,959
47	1715B	Station Equipment (Protection and Control)	1,485,731	5,738	-	1,491,470	20	24,762	74,894		99,656	1,391,813
47	1720	Towers and Fixtures	112,607,525	-	-	112,607,525	60	625,597	1,884,477		2,510,074	110,097,451
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	134,211,114	-	-	134,211,114	45	994,156	2,972,223		3,966,379	130,244,735
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**290,311,326**	**391,335**	**-**	**290,702,661**		**1,934,824**	**5,810,038**	**-**	**7,744,862**	**282,957,799**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	290,311,326	391,335	-	290,702,661		1,934,824	5,810,038	-	7,744,862	282,957,799
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							5,810,038			

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard	ASPE
Year	2023

CCA Class	**OEB**	**Description**	**Opening Gross PP&E**	**Less Fully Depreciated**	**Net for Depreciation**	**Current Year Additions**	**Total for Depreciation**	**Useful Life**	**Depreciation Rate**	**Depreciation Expense**
Transmission Plant			*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	35,850,038	-	35,850,038	349,381	36,170,303	50	2.00%	721,577
47	1715A	Station Equipment (Switches and Breakers)	6,156,918	-	6,156,918	36,216	6,190,116	40	2.50%	156,867
47	1715B	Station Equipment (Protection and Control)	1,485,731	-	1,485,731	5,738	1,490,991	20	5.00%	74,894
47	1720	Towers and Fixtures	112,607,525	-	112,607,525	-	112,607,525	60	1.67%	1,884,477
47	1725	Poles and Fixtures	-	-	-	-	-	-	-	-
47	1730	OH Cond and Devices	134,211,114	-	134,211,114	-	134,211,114	45	2.22%	2,972,223
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**290,311,326**	**-**	**290,311,326**	**391,335**	**290,670,050**			**5,810,038**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2023

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	64,456,846	116,198,115	-	180,654,961	50	190,998	2,173,763		2,364,761	178,290,199
47	1715A	Station Equipment (Switches and Breakers)	6,615,305	8,262,621	-	14,877,926	40	26,330	244,731		271,061	14,606,865
47	1715B	Station Equipment (Protection and Control)	2,874,284	4,655,949	-	7,530,233	20	20,795	230,401		251,197	7,279,036
47	1720	Towers and Fixtures	142,608,709	126,240,734	-	268,849,443	60	348,975	3,117,856		3,466,830	265,382,613
47	1725	Poles and Fixtures	1,727,765	31,766,200	-	33,493,965	45	4,123	365,662		369,785	33,124,180
47	1730	OH Cond and Devices	170,593,250	146,865,837	-	317,459,087	45	562,878	4,933,736		5,496,614	311,962,474
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**388,876,158**	**433,989,457**	**-**	**822,865,615**		**1,154,099**	**11,066,149**	**-**	**12,220,248**	**810,645,367**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	388,876,158	433,989,457	-	822,865,615		1,154,099	11,066,149	-	12,220,248	810,645,367
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							11,066,149			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**11,066,149**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard ASPE
Year 2023

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	A	B	C = A - B	D	E = Avg Monthly Opening	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	64,456,846	-	64,456,846	116,198,115	108,688,152	50	2.00%	2,173,763
47	1715A	Station Equipment (Switches and Breakers)	6,615,305	-	6,615,305	8,262,621	9,789,243	40	2.50%	244,731
47	1715B	Station Equipment (Protection and Control)	2,874,284	-	2,874,284	4,655,949	4,608,029	20	5.00%	230,401
47	1720	Towers and Fixtures	142,608,709	-	142,608,709	126,240,734	187,071,347	60	1.67%	3,117,856
47	1725	Poles and Fixtures	1,727,765	-	1,727,765	31,766,200	16,454,777	45	2.22%	365,662
47	1730	OH Cond and Devices	170,593,250	-	170,593,250	146,865,837	222,018,125	45	2.22%	4,933,736
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**388,876,158**	**-**	**388,876,158**	**433,989,457**	**548,629,673**			**11,066,149**

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2024

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	300,000	3,000,000	-	3,300,000	5	10,000	610,000		620,000	2,680,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	216,854,379	145,838,566	-	362,692,945	50	3,325,339	6,028,958		9,354,296	353,338,648
47	1715A	Station Equipment (Switches and Breakers)	21,071,060	10,189,112	-	31,260,171	40	479,236	667,240		1,146,475	30,113,696
47	1715B	Station Equipment (Protection and Control)	9,021,703	5,853,461	-	14,875,164	20	350,853	607,477		958,331	13,916,833
47	1720	Towers and Fixtures	381,456,968	231,572,120	-	613,029,088	60	5,976,904	8,480,678		14,457,582	598,571,506
47	1725	Poles and Fixtures	33,493,965	2,024,377	-	35,518,342	45	369,785	767,121		1,136,906	34,381,436
47	1730	OH Cond and Devices	451,670,202	237,516,888	-	689,187,090	45	9,462,993	13,145,372		22,608,365	666,578,724
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	-	5,000,000	-	5,000,000	50	-	16,667		16,667	4,983,333
8	1915	Office Furn & Equipment	40,000	80,000	-	120,000	10	2,000	9,667		11,667	108,333
	1920	Comp Hardware	-	-	-	-	-	-	-		-	-
10.1	1930	Transportation Equipment	155,392	670,000	-	825,392	5	46,617	99,912		146,529	678,863
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-		-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-		-		-	-
	1950	Power Operated Equipment	-	-	-	-	-		-		-	-
	1955	Communication Equipment	-	-	-	-	-		-		-	-
	1960	Misc. Equipment	-	-	-	-	-		-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-		-		-	-
	1995	Contributions & Grants	-	-	-	-	-		-		-	-
	2440	Deferred Revenue	-	-	-	-	-		-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**1,114,063,668**	**641,744,523**	**-**	**1,755,808,191**		**20,023,728**	**30,433,091**	**-**	**50,456,818**	**1,705,351,373**
	2055	**Add: Construction Work in Progress**	637,532,325	4,212,198	(641,744,523)	0					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,751,595,993	645,956,721	(641,744,523)	1,755,808,191		20,023,728	30,433,091	-	50,456,818	1,705,351,373
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							30,433,091			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**30,433,091**

Calculation of Depreciation Expense - All Assets

Accounting Standard ASPE
Year 2024

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Intangible	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	300,000	-	300,000	3,000,000	3,050,000	5	20.00%	610,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	216,854,379	-	216,854,379	145,838,566	301,447,883	50	2.00%	6,028,958
47	1715A	Station Equipment (Switches and Breakers)	21,071,060	-	21,071,060	10,189,112	26,689,589	40	2.50%	667,240
47	1715B	Station Equipment (Protection and Control)	9,021,703	-	9,021,703	5,853,461	12,149,550	20	5.00%	607,477
47	1720	Towers and Fixtures	381,456,968	-	381,456,968	231,572,120	508,840,677	60	1.67%	8,480,678
47	1725	Poles and Fixtures	33,493,965	-	33,493,965	2,024,377	34,520,424	45	2.22%	767,121
47	1730	OH Cond and Devices	451,670,202	-	451,670,202	237,516,888	591,541,755	45	2.22%	13,145,372
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		General Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	5,000,000	833,333	50	2.00%	16,667
8	1915	Office Furn & Equipment	40,000	-	40,000	80,000	96,667	10	10.00%	9,667
	1920	Comp Hardware	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	155,392	-	155,392	670,000	499,558	5	20.00%	99,912
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**1,114,063,668**	**-**	**1,114,063,668**	**641,744,523**	**1,479,669,437**			**30,433,091**

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard	ASPE
Year	2024

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	36,199,418	9,702,189	-	45,901,608	50	960,577	900,033		1,860,610	44,040,997
47	1715A	Station Equipment (Switches and Breakers)	6,193,134	-	-	6,193,134	40	208,174	156,942		365,117	5,828,017
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	-	1,491,470	20	99,656	74,918		174,575	1,316,895
47	1720	Towers and Fixtures	112,607,525	1,635,674	-	114,243,199	60	2,510,074	1,909,466		4,419,540	109,823,659
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	134,211,114	20,274,716	-	154,485,830	45	3,966,379	3,385,227		7,351,606	147,134,224
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**290,702,661**	**31,612,579**	**-**	**322,315,240**		**7,744,862**	**6,426,586**	**-**	**14,171,448**	**308,143,792**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	290,702,661	31,612,579	-	322,315,240		7,744,862	6,426,586	-	14,171,448	308,143,792
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							6,426,586			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**6,426,586**

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard	ASPE
Year	2024

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	36,199,418	-	36,199,418	9,702,189	45,001,642	50	2.00%	900,033
47	1715A	Station Equipment (Switches and Breakers)	6,193,134	-	6,193,134	-	6,277,690	40	2.50%	156,942
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	1,491,470	-	1,498,363	20	5.00%	74,918
47	1720	Towers and Fixtures	112,607,525	-	112,607,525	1,635,674	114,567,969	60	1.67%	1,909,466
47	1725	Poles and Fixtures	-	-	-	-	-	-	-	-
47	1730	OH Cond and Devices	134,211,114	-	134,211,114	20,274,716	152,335,195	45	2.22%	3,385,227
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**290,702,661**	**-**	**290,702,661**	**31,612,579**	**319,680,858**			**6,426,586**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard	ASPE
Year	2024

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	180,654,961	136,136,377	-	316,791,337	50	2,364,761	5,128,925		7,493,686	309,297,651
47	1715A	Station Equipment (Switches and Breakers)	14,877,926	10,189,112	-	25,067,038	40	271,061	510,297		781,359	24,285,679
47	1715B	Station Equipment (Protection and Control)	7,530,233	5,853,461	-	13,383,694	20	251,197	532,559		783,756	12,599,938
47	1720	Towers and Fixtures	268,849,443	229,936,446	-	498,785,889	60	3,466,830	6,571,212		10,038,042	488,747,847
47	1725	Poles and Fixtures	33,493,965	2,024,377	-	35,518,342	45	369,785	767,121		1,136,906	34,381,436
47	1730	OH Cond and Devices	317,459,087	217,242,172	-	534,701,260	45	5,496,614	9,760,146		15,256,759	519,444,500
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**822,865,615**	**601,381,944**	**-**	**1,424,247,559**		**12,220,248**	**23,270,260**	**-**	**35,490,508**	**1,388,757,051**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	822,865,615	601,381,944	-	1,424,247,559		12,220,248	23,270,260	-	35,490,508	1,388,757,051
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							23,270,260			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**

Transportation	
Stores Equipment	
Net Depreciation	**23,270,260**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard ASPE
Year 2024

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	A	B	C = A - B	D	E = Avg Monthly Opening	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	180,654,961	-	180,654,961	136,136,377	256,446,241	50	2.00%	5,128,925
47	1715A	Station Equipment (Switches and Breakers)	14,877,926	-	14,877,926	10,189,112	20,411,899	40	2.50%	510,297
47	1715B	Station Equipment (Protection and Control)	7,530,233	-	7,530,233	5,853,461	10,651,187	20	5.00%	532,559
47	1720	Towers and Fixtures	268,849,443	-	268,849,443	229,936,446	394,272,709	60	1.67%	6,571,212
47	1725	Poles and Fixtures	33,493,965	-	33,493,965	2,024,377	34,520,424	45	2.22%	767,121
47	1730	OH Cond and Devices	317,459,087	-	317,459,087	217,242,172	439,206,561	45	2.22%	9,760,146
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**822,865,615**	**-**	**822,865,615**	**601,381,944**	**1,155,509,021**			**23,270,260**

Fixed Asset Continuity Schedule - All Assets

Accounting Standard	ASPE
Year	2023

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	-	300,000	-	300,000	5	-	10,000		10,000	290,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	100,306,884	116,547,496	-	216,854,379	50	429,999	2,895,340		3,325,339	213,529,040
47	1715A	Station Equipment (Switches and Breakers)	12,772,222	8,298,837	-	21,071,060	40	77,638	401,598		479,236	20,591,824
47	1715B	Station Equipment (Protection and Control)	4,360,015	4,661,688	-	9,021,703	20	45,558	305,296		350,853	8,670,849
47	1720	Towers and Fixtures	255,216,234	126,240,734	-	381,456,968	60	974,572	5,002,332		5,976,904	375,480,064
47	1725	Poles and Fixtures	1,727,765	31,766,200	-	33,493,965	45	4,123	365,662		369,785	33,124,180
47	1730	OH Cond and Devices	304,804,364	146,865,837	-	451,670,202	45	1,557,034	7,905,959		9,462,993	442,207,208
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	50	-	-		-	-
8	1915	Office Furn & Equipment	-	40,000	-	40,000	10	-	2,000		2,000	38,000
	1920	Comp Hardware	-	-	-	-	-	-	-		-	-
10.1	1930	Transportation Equipment	155,392	-	-	155,392	5	15,539	31,078		46,617	108,774
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-		-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-		-		-	-
	1950	Power Operated Equipment	-	-	-	-	-		-		-	-
	1955	Communication Equipment	-	-	-	-	-		-		-	-
	1960	Misc. Equipment	-	-	-	-	-		-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-		-		-	-
	1995	Contributions & Grants	-	-	-	-	-		-		-	-
	2440	Deferred Revenue	-	-	-	-	-		-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**679,342,875**	**434,720,792**	**-**	**1,114,063,668**		**3,104,462**	**16,919,265**	**-**	**20,023,728**	**1,094,039,940**
	2055	**Add: Construction Work in Progress**	602,803,992	469,449,125	(434,720,792)	637,532,325					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,282,146,868	904,169,918	(434,720,792)	1,751,595,993		3,104,462	16,919,265	-	20,023,728	1,094,039,940
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							16,919,265			

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard ASPE
Year 2023

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	35,850,038	349,381	-	36,199,418	50	239,000	721,577		960,577	35,238,841
47	1715A	Station Equipment (Switches and Breakers)	6,156,918	36,216	-	6,193,134	40	51,308	156,867		208,174	5,984,959
47	1715B	Station Equipment (Protection and Control)	1,485,731	5,738	-	1,491,470	20	24,762	74,894		99,656	1,391,813
47	1720	Towers and Fixtures	112,607,525	-	-	112,607,525	60	625,597	1,884,477		2,510,074	110,097,451
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	134,211,114	-	-	134,211,114	45	994,156	2,972,223		3,966,379	130,244,735
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**290,311,326**	**391,335**	**-**	**290,702,661**		**1,934,824**	**5,810,038**	**-**	**7,744,862**	**282,957,799**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	290,311,326	391,335	-	290,702,661		1,934,824	5,810,038	-	7,744,862	282,957,799
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							5,810,038			

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2023

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	64,456,846	116,198,115	-	180,654,961	50	190,998	2,173,763		2,364,761	178,290,199
47	1715A	Station Equipment (Switches and Breakers)	6,615,305	8,262,621	-	14,877,926	40	26,330	244,731		271,061	14,606,865
47	1715B	Station Equipment (Protection and Control)	2,874,284	4,655,949	-	7,530,233	20	20,795	230,401		251,197	7,279,036
47	1720	Towers and Fixtures	142,608,709	126,240,734	-	268,849,443	60	348,975	3,117,856		3,466,830	265,382,613
47	1725	Poles and Fixtures	1,727,765	31,766,200	-	33,493,965	45	4,123	365,662		369,785	33,124,180
47	1730	OH Cond and Devices	170,593,250	146,865,837	-	317,459,087	45	562,878	4,933,736		5,496,614	311,962,474
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**388,876,158**	**433,989,457**	**-**	**822,865,615**		**1,154,099**	**11,066,149**	**-**	**12,220,248**	**810,645,367**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	388,876,158	433,989,457	-	822,865,615		1,154,099	11,066,149	-	12,220,248	810,645,367
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							11,066,149			

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2024

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	300,000	3,000,000	-	3,300,000	5	10,000	610,000		620,000	2,680,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	216,854,379	145,838,566	-	362,692,945	50	3,325,339	6,028,958		9,354,296	353,338,648
47	1715A	Station Equipment (Switches and Breakers)	21,071,060	10,189,112	-	31,260,171	40	479,236	667,240		1,146,475	30,113,696
47	1715B	Station Equipment (Protection and Control)	9,021,703	5,853,461	-	14,875,164	20	350,853	607,477		958,331	13,916,833
47	1720	Towers and Fixtures	381,456,968	231,572,120	-	613,029,088	60	5,976,904	8,480,678		14,457,582	598,571,506
47	1725	Poles and Fixtures	33,493,965	2,024,377	-	35,518,342	45	369,785	767,121		1,136,906	34,381,436
47	1730	OH Cond and Devices	451,670,202	237,516,888	-	689,187,090	45	9,462,993	13,145,372		22,608,365	666,578,724
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	-	5,000,000	-	5,000,000	50	-	16,667		16,667	4,983,333
8	1915	Office Furn & Equipment	40,000	80,000	-	120,000	10	2,000	9,667		11,667	108,333
	1920	Comp Hardware	-	-	-	-	-	-	-		-	-
10.1	1930	Transportation Equipment	155,392	670,000	-	825,392	5	46,617	99,912		146,529	678,863
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-		-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-		-		-	-
	1950	Power Operated Equipment	-	-	-	-	-		-		-	-
	1955	Communication Equipment	-	-	-	-	-		-		-	-
	1960	Misc. Equipment	-	-	-	-	-		-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-		-		-	-
	1995	Contributions & Grants	-	-	-	-	-		-		-	-
	2440	Deferred Revenue	-	-	-	-	-		-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**1,114,063,668**	**641,744,523**	**-**	**1,755,808,191**		**20,023,728**	**30,433,091**	**-**	**50,456,818**	**1,705,351,373**
	2055	**Add: Construction Work in Progress**	637,532,325	4,212,198	(641,744,523)	0					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,751,595,993	645,956,721	(641,744,523)	1,755,808,191		20,023,728	30,433,091	-	50,456,818	1,705,351,373
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							30,433,091			

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard ASPE
Year 2024

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	36,199,418	9,702,189	-	45,901,608	50	960,577	900,033		1,860,610	44,040,997
47	1715A	Station Equipment (Switches and Breakers)	6,193,134	-	-	6,193,134	40	208,174	156,942		365,117	5,828,017
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	-	1,491,470	20	99,656	74,918		174,575	1,316,895
47	1720	Towers and Fixtures	112,607,525	1,635,674	-	114,243,199	60	2,510,074	1,909,466		4,419,540	109,823,659
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	134,211,114	20,274,716	-	154,485,830	45	3,966,379	3,385,227		7,351,606	147,134,224
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**290,702,661**	**31,612,579**	**-**	**322,315,240**		**7,744,862**	**6,426,586**	**-**	**14,171,448**	**308,143,792**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	290,702,661	31,612,579	-	322,315,240		7,744,862	6,426,586	-	14,171,448	308,143,792
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							6,426,586			

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2024

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	180,654,961	136,136,377	-	316,791,337	50	2,364,761	5,128,925		7,493,686	309,297,651
47	1715A	Station Equipment (Switches and Breakers)	14,877,926	10,189,112	-	25,067,038	40	271,061	510,297		781,359	24,285,679
47	1715B	Station Equipment (Protection and Control)	7,530,233	5,853,461	-	13,383,694	20	251,197	532,559		783,756	12,599,938
47	1720	Towers and Fixtures	268,849,443	229,936,446	-	498,785,889	60	3,466,830	6,571,212		10,038,042	488,747,847
47	1725	Poles and Fixtures	33,493,965	2,024,377	-	35,518,342	45	369,785	767,121		1,136,906	34,381,436
47	1730	OH Cond and Devices	317,459,087	217,242,172	-	534,701,260	45	5,496,614	9,760,146		15,256,759	519,444,500
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**822,865,615**	**601,381,944**	**-**	**1,424,247,559**		**12,220,248**	**23,270,260**	**-**	**35,490,508**	**1,388,757,051**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	822,865,615	601,381,944	-	1,424,247,559		12,220,248	23,270,260	-	35,490,508	1,388,757,051
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							23,270,260			

Exhibit C, Tab 4, Schedule 1

Allowance for Working Capital

ALLOWANCE FOR WORKING CAPITAL

WPLP does not have sufficient historical revenues on which to base an analysis of revenue lag, nor does it have significant experience under negotiated settlement agreements with IESO or HORCI. WPLP has therefore not prepared a lead/lag study for 2024 and has not requested an allowance for working capital in its 2024 test year rate base. WPLP will consider filing a lead/lag study as part of its first multi-year revenue requirement application, for a period beginning with a 2026 test year, by which time its forecasted revenue lags are expected to become more certain.

Exhibit C, Tab 5, Schedule 1

Customer Connections and Cost Recovery Agreements

CUSTOMER CONNECTIONS AND COST RECOVERY AGREEMENTS

Section 2.5.2 of the Filing Requirements specifies that certain information must be provided when proposed capital expenditures require contributions from a customer and/or where Connection and Cost Recovery Agreements ("CCRA") are due for review.

In its decision and order in EB-2018-0190, the OEB found "that the Line to Pickle Lake is a network facility for which exceptional circumstances under section 6.3.5 of the TSC do not exist at this time."[1] As a result of this finding, section 6.3.5 of the TSC provides that WPLP will not require any customer to make a capital contribution toward the cost of the Line to Pickle Lake.

With respect to the Remote Connection Lines, the OEB approved WPLP's proposed cost recovery and rate framework, specifically "the inclusion of the net capital cost associated with the Remote Connection Lines in WPLP's rate base and a monthly fixed charge applied to HORCI – in lieu of a capital contribution."[2]

The OEB also approved WPLP's request for temporary exemptions from various TSC provisions related to cost recovery and cost responsibility, until such time as all facilities are placed in service or December 31, 2023.[3] Specifically, WPLP's transmission licence was amended to include exemptions from all sections of the TSC relating to customer capital contributions and cost responsibility in respect of connection facilities, subject to a number of conditions. These conditions include, among other things, a requirement for WPLP to file Customer Connection Procedures ("CCPs") with the OEB by December 31, 2022, and a requirement for WPLP to seek further direction from the OEB in the event that it receives one or more connection requests in advance of the OEB's approval of its CCPs. As discussed below, WPLP filed an application with the OEB on December 16, 2022, requesting, among other things, an extension of such exemptions to reflect the extended project construction and in-service schedule.

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[1] EB-2018-0190, Decision and Order dated April 1, 2019, p. 23.

[2] EB-2018-0190, Decision and Order dated April 1, 2019, pp. 27-28.

[3] EB-2018-0190, Decision and Order dated April 1, 2019, p. 23.

In anticipation of the previously scheduled connection date of WPLP's Transmission System to HORCI's distribution system in Pikangikum First Nation, and consistent with the approach approved in EB-2018-0190, WPLP requested interim approval from the OEB on June 30, 2022, for modifications to discrete sections of the standard form of connection agreement set out for load customers in Appendix 1 (Version A) of the TSC (the "Standard Connection Agreement") in respect of its connection agreement with HORCI. In the Decision and Order of the OEB in EB-2022-0199, the OEB granted WPLP's requested modifications for its connection agreement with HORCI on an interim basis with a requirement to seek approval on a final basis prior to the end of 2022 (EB-2022-0199).

On December 16, 2022, WPLP filed an application with the OEB requesting (i) approval on a final basis for the modifications to the Standard Connection Agreement as reflected in its connection agreement with HORCI, (ii) approval of its CCPs and to amend the effective date of its CCPs as specified in WPLP's Transmission Licence to the later of September 1, 2024 and the date all facilities are placed into service, and (iii) approval to extend the period of certain TSC exemptions as specified in Schedule 2 of WPLP's Transmission Licence due to the extended project construction and in-service schedule (EB-2022-0330). On April 6, 2023, the OEB issued its Decision and Order in EB-2022-0330, granting the requested relief. In particular, the OEB approved:

- On a final basis, WPLP's proposed modifications to the Standard Connection Agreement in its connection agreement with HORCI;

- WPLP's proposed CCPs;

- an extension of the effective date for WPLP's CCPs to the later of September 1, 2024 and the date all facilities are placed into service (from the date on which all of the facilities are placed in service, or January 1, 2024, whichever is earlier);

- for the Remote Connection Lines, a one-year extension (from December 31, 2023 to December 31, 2024) to the exemptions from all sections of the TSC related to connection procedures and customer capital contributions for connection facilities and cost responsibility in relation to connecting the Listed Communities; and

- WPLP’s request to extend its RRR exemption by granting a one-year extension to RRR financial disclosure obligations, which will result in the commencement of reporting in 2026, rather than 2025.

Exhibit C, Tab 6, Schedule 1

Capitalization Policy

CAPITALIZATION POLICY

A. Capitalization Policy

As noted in Exhibit A-7-1, WPLP accounts for capital assets in accordance with the Accounting Standards for Private Enterprises (ASPE). Costs included in the carrying amount of property, plant and equipment (i.e. CWIP) include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects are capitalized during the construction period if the capital assets associated with such projects meet the definition of a qualifying asset. Major projects (qualifying assets) are those projects that are under construction for a substantial period of time. Assets under construction are recorded in the CWIP account until they are available for use.

WPLP's adherence to the capitalization requirements under ASPE can be described as follows:

- Assets that are intended to be used on a continuing basis and are expected to provide future economic benefit (generally considered greater than one year) will be capitalized.

- General Plant items with an estimated useful life of greater than one year and valued at greater than $500 will be capitalized.

- Expenditures that create physical betterment or improvement of the asset (i.e. there is a significant increase in physical output or service capacity, or the useful life of the capital asset is extended) will be capitalized.

- Materials and supplies are charged to capital on the basis of actual costs for non-stock materials and the weighted average price for materials in inventory.

- Overhead costs (including labour costs and related departmental costs) incurred during the development and construction period (i.e. to December 31, 2024) will be capitalized on a declining basis, in consideration of the portion of WPLP's transmission system assets in service.[1]

B. Capitalization of Overhead and Burden Rates

Overhead costs (including labour costs and related departmental costs) incurred during the development and construction period (i.e. to December 31, 2024) will be capitalized on a declining basis, in consideration of the portion of WPLP's transmission system assets in service. As a result of this methodology, burden rates are not relevant to the determination of WPLP's 2024 revenue requirement.

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[1] See Appendix 'A' of Exhibit B-1-5 for a description of these overhead costs and detail of the capitalization/allocation methodology.

Exhibit D, Tab 1, Schedule 1

Proposed Scorecard

PROPOSED SCORECARD

Section 2.6 (Exhibit 4) of the Filing Requirements outlines the OEB's expectations in relation to reporting on service quality and reliability performance, specifically in relation to scorecard measures aligned with the OEB's four categories of RRF outcomes and reporting related to system reliability. This schedule addresses the OEB's scorecard expectations relative to WPLP's circumstances of constructing a new transmission system. Reliability expectations in the context of WPLP's transmission system are addressed in Tab 2 of this Exhibit.

A. WPLP's Circumstances

The initial segments of WPLP's transmission system, consisting of the Line to Pickle and segments of the Remote Connection Lines connecting two communities were placed into service in 2022, with additional segments being put into service at different points during the 2023 bridge year and remaining segments expected to go into service during the 2024 test year. After primarily focusing on construction activities during the 2020-2024 period, WPLP's Transmission System is expected to be in service in its entirety by the end of 2024. Since the portion of WPLP's Transmission System in service will vary significantly from month to month over this period, as additional segments are completed, the tracking of typical transmission scorecard measures would be impractical and provide little value in comparing WPLP to other transmitters. WPLP will begin tracking information for typical scorecard measures related to safety, reliability and costs during the construction period so that this information can be used in setting future performance expectations, with consideration for any adjustments required to reflect the transition from construction to operation. WPLP therefore intends to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year. That scorecard will propose measures that will be tracked starting in 2025, which will be the first full year that WPLP's entire transmission system is in service.

In the interim, until WPLP is in a position to file a draft scorecard, the OEB will have the benefit of other information on project status and performance. Specifically, as a condition of approval in EB-2018-0190, WPLP is required to provide the OEB with semi-annual updates on the CWIP account, as well as on the progress of backup supply arrangements for the connecting communities. In addition, in accordance with the approved Settlement Agreement from EB-2021-0134, WPLP has expanded the scope of its semi-annual reports commencing with the October 15, 2021 report to include information on the expected connection dates of the remote communities, updates to operations and material changes to long-term operating plans, updated information on the transfer of distribution system assets from Independent Power Authorities to HORCI and updates on community readiness for those communities already served by HORCI. These updates provide the OEB with information relevant to WPLP's physical progress and cost performance in the construction of its transmission system.[1]

Furthermore, in accordance with the approved Settlement Agreement from EB-2021-0134, the parties agreed that WPLP would track certain information to facilitate the setting of future performance expectations. Specifically, the parties agreed that, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that will be placed into service in 2022, WPLP will monitor performance on the basis of the following reliability metrics without establishing performance targets and report to the OEB on such performance, based on data as at Year End 2022, in approximately April 2023[2] consistent with the timing of (but not pursuant to) the OEB's RRR reporting requirements:

- Total Recordable Injuries Frequency Rate ("TRIFR") - # of recordable injuries per 200,000 hours worked, using Canadian Electricity Association definition of "recordable injuries";
- Recordable Injuries - (# of recordable injuries per year, using Canadian Electricity Association definition of "recordable injuries");
- Violations of NERC FAC-003-4 Vegetation Compliance Standard (in respect of the Line to Pickle Lake portion of the transmission system only);
- OM&A cost per kilometer of line and OM&A cost per station;

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[1] Outside of this rate application, the Semi-Annual Report dated April 17, 2023 in EB-2018-0190 contains the most recent update on physical progress and cost performance in the construction of its transmission system

[2] The report was filed with the OEB on May 12, 2023.

- Average system availability;
- Transmission System Average Interruption Duration Index (T-SAIDI); and
- Transmission System Average Interruption Frequency Index (T-SAIFI).

In connection with the two metrics listed above for Recordable Incidents, the parties also agreed that WPLP would advise the OEB if and when the Canadian Electricity Association amends its definition of “recordable injuries”.

WPLP proposes to continue to monitor performance on the basis of the above reliability metrics without establishing performance targets and to report to the OEB on such performance, based on data as at Year End 2023 and as at Year End 2024, in approximately April 2024 and April 2025, respectively, consistent with the timing of (but not pursuant to) the OEB’s RRR reporting requirements.

Furthermore, pursuant to the Settlement Agreement in EB-2022-0149, WPLP agreed to the following in respect of monitoring and reporting:

- **Semi-Annual Reports:** Provide additional information in the semi-annual reports that WPLP is required to file with the OEB pursuant to EB-2016-0262, including (i) how the scopes of work under the Control Room Services Agreement and the Inspection, Maintenance and Emergency Response Agreement (“IMER Agreement”) would be performed, (ii) the nature and status of permitting and engagement required for operational access, and (iii) WPLP’s fleet and facilities plans.

- **Project/construction monitoring and reporting:** If the community connection schedule changes (including in respect of Pikangikum First Nation), post the updated schedule on WPLP’s website and file a copy of the updated schedule with the OEB in EB-2022-0149. Provide to HORCI on a monthly basis information and concerns received in relation to issues relevant to HORCI, as well as a summary of the issues and concerns raised by First Nations that are likely to delay connection or to continue to relevant to HORCI post-connection.

- **Community Communications:** Participate in meetings if a First Nation community requests a meeting with or presentation by HORCI in advance of a community connection date and the community invites WPLP, focusing on WPLP's respective scope of work and in alignment with the First Nation community's expectations.

In the Settlement Agreement in EB-2022-0149, the Parties agreed that WPLP's communications and engagement protocols with First Nations would be at all times preserved and respected, and that the terms in the Settlement Agreement in EB-2022-0149 would not and were not intended to override, dictate or otherwise constrain the manner or substance of WPLP's communications or engagement with First Nations.

The remainder of this schedule sets out how WPLP's activities to date and various aspect of the semi-annual reporting align with the OEB's four categories of RRF outcomes.

1. RRF Outcome #1 – Customer Focus

WPLP's sole customer at this time is HORCI, and the quality of service that WPLP provides to HORCI will have a direct impact on the quality of distribution service that HORCI is able to provide to customers in the connecting communities. WPLP intends to coordinate with HORCI to ensure that its customer-focused performance metrics are presented in a way that complements any similar metrics reported by HORCI, and provides appropriate context related to the quality of service experienced by end-use customers in the connecting communities. WPLP and HORCI have established formal operational and communications protocols in relation to First Nation already connected to transmission system. WPLP expects to expand on these protocols based on experience with and feedback from HORCI as additional transmission assets are placed in service based on operating experience. WPLP provides HORCI with monthly outage reports and reliability summaries, and will engage with HORCI to consider how customer delivery point performance standards will be integrated with plans for backup power, as further discussed in Exhibit B-1-2. Progress on backup power plans for each community is a core requirement of WPLP's semi-annual reports until such time as a solution is implemented for each community to be connected to WPLP's Transmission System.

2. RRF Outcome #2 – Operational Effectiveness

Since the vast majority of WPLP's 2020-2024 costs will be focused on the initial construction of its Transmission System, the initial scorecard that WPLP plans to file in 2025 in support of its multi-year 2026 revenue requirement application will be an appropriate starting point for implementing metrics related to the ongoing operation of and reinvestment in the system.

Further, as indicated in Exhibit B-1-1, WPLP expects to file an initial TSP in 2025 in support of its application for rates for 2026 and subsequent years. WPLP expects that the TSP will include a number of performance measures and targets related to operational effectiveness that will be consistent with the scorecard it would then propose.

Finally, worker health and safety, public safety and the protection of the natural environment ("Health, Safety and Environment" or "HSE") are of the utmost importance to WPLP. WPLP has established HSE policies and is in the process of developing and implementing comprehensive procedures and management systems that support those policies. WPLP will incorporate HSE-related metrics into its future scorecard.

3. RRF Outcome #3 – Public Policy Responsiveness

The initial construction of WPLP's Transmission System and the connection of 16 remote First Nation communities[3] is a result of the 24 Participating First Nations forming a partnership on the basis of their shared interest in developing, owning and operating transmission facilities to connect remote First Nation communities (which are currently powered by diesel generation) to the provincial electricity grid, so as to provide reliable and accessible power to residents and businesses in the region.[4] The project is directly aligned with policy objectives of the provincial and federal governments to connect remote communities, as further detailed in Exhibit B-3-1.

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[3] Including the design to allow the future connection of a 17th community, McDowell Lake First Nation.

[4] WPLP's development, construction and operation of the Transmission System will also abide by the Guiding Principles, as approved by the leadership of the Participating First Nations.

4. RRF Outcome #4 – Financial Performance

In addition to the CWIP reporting discussed above, WPLP will file all required financial information under the OEB's Electricity Reporting and Record Keeping Requirements.[5] Furthermore, the current application includes, and the single test year application that WPLP intends to file for the 2025 test year, which will include information on WPLP's actual costs as compared to its cost forecasts and information sufficient to calculate a number of financial ratios (e.g. liquidity, leverage), and deemed vs. actual ROE. WPLP's future scorecard metrics will include similar financial ratios as reported by LDC's and other transmitters.

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[5] Under its Transmission Licence, WPLP is exempt from Sections 3.1.1 through 3.1.4, inclusive, of the Electricity Reporting and Record Keeping Requirements. This exemption applies in respect of the 2019 to 2024 reporting periods. WPLP is required to commence reporting under Sections 3.1.1 through 3.1.4 of the Electricity Reporting and Record Keeping Requirements in 2026 in respect of the 2025 reporting period.

Exhibit D, Tab 2, Schedule 1

Reliability Performance

RELIABILITY PERFORMANCE

Section 2.6.2 of the OEB’s Filing Requirements specifies that applicants must document their achieved reliability performance using various specified measures. WPLP has tracked historical reliability performance information in respect of the distribution line serving Pikangikum, which is summarized below. However, as that line operated temporarily as a distribution line, the corresponding reliability performance data is of limited value for future comparison, particularly with respect to loss of supply outages and planned outages for conversion from 44 kV to 115 kV.

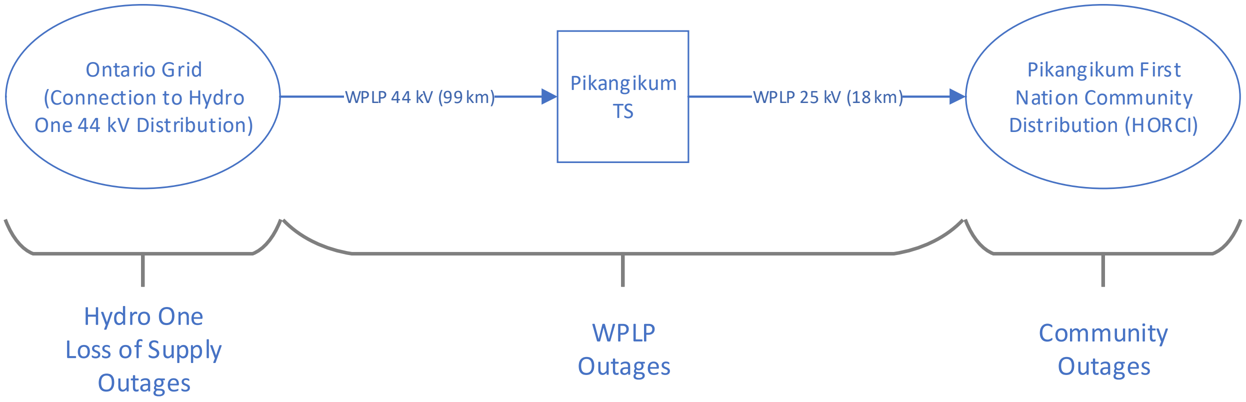
As noted in Exhibit D-1-1, the parties to the Settlement Agreement in EB-2021-0134 agreed that in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that will be placed into service in 2022, WPLP will monitor performance based on certain agreed-upon reliability metrics without establishing performance targets and that WPLP will report to the OEB on such performance in approximately April 2023, based on data as at year end 2022. Such report was filed with the OEB on May 12, 2023 and the reliability performance for transmission assets placed into service in 2022 is summarized in Section B below. As further noted in Exhibit D-1-1, WPLP proposes to continue to monitor its performance on the same basis and report to the OEB on such performance in approximately April 2024, based on data as at year end 2023, and in approximately April 2025, based on data as at year end 2024.

A. Pikangikum Distribution System Reliability Performance

WPLP developed and implemented an innovative solution to address the critical need for grid connection of the Pikangikum First Nation on an accelerated schedule, while largely avoiding the duplication of electricity infrastructure, by constructing an approximately 117 km line to a transmission standard but operating it on an interim basis at a distribution voltage while connected to HONI’s distribution system and converting the line to operate at a transmission voltage at such time that it can be connected to HONI’s transmission system and integrated into WPLP’s Transmission System. WPLP’s distribution line to Pikangikum was completed and went into service on December 20, 2018. The Pikangikum distribution line was converted to form part of the Transmission System in May 2023. As such, approximately four and a half years of reliability performance data for the line is available.

In order to provide context for the reliability performance information that follows, Figure 1 provides a simplified illustration of the connection of the Pikangikum First Nation to the Ontario grid, via WPLP's Pikangikum Distribution System. Figure 1 also illustrates the differences between outages originating on WPLP's distribution system ("WPLP Outages"), as compared to outages originating upstream of that distribution system ("Loss of Supply Outages") or outages originating in the community ("Community Outages").

Figure 1 – Simplified Connection of Pikangikum Distribution System



In 2019, Pikangikum First Nation experienced eight outages that affected the entire community:

- Two Hydro One Loss of Supply Outages originated on Hydro One's upstream transmission/distribution network.

- One WPLP Outage originated as a Community Outage, however most of the outage duration was related to issues with settings and coordination on a WPLP recloser that have since been resolved.

- One WPLP Outage occurred when WPLP de-energized its distribution system at the request of MNRF to allow for safe aerial water-bombing of an out-of-control forest fire in the vicinity of WPLP's assets.

- Four Community Outages tripped the recloser at the WPLP/HORCI demarcation point, resulting in community-wide outages.

In 2020, Pikangikum First Nation experienced two community-wide outages, both of which were Hydro One Loss of Supply Outages.

In 2021, Pikangikum First Nation experienced seven community-wide outages, two of which related to WPLP Outages and five of which related to Hydro One Loss of Supply Outages. The two WPLP Outages related to maintenance within the substation.

In 2022, Pikangikum First Nation experienced four community-wide outages, three of which related to WPLP Outages and one of which related to a Hydro One Loss of Supply Outage. Two of the three WPLP Outages were planned in advance and related to work required to convert from HONI's 44 kV distribution system to Wataynikaneyap Power's 115 kV transmission system. The third WPLP outage related to unintended WPLP protection operations following capacitor bank switching at a nearby Hydro One substation.

B. Transmission System Reliability Performance

In 2022, WPLP's Pickle Lake Remote Connection Line experienced two outages to transmission delivery points:

- A vehicle contact with a 25 kV pole on the HORCI distribution system in North Caribou Lake First Nation caused WPLP's substation breakers to trip and reclose. This event was recorded as a momentary outage by WPLP (WPLP's circuit breakers tripped and reclosed approximately 2 seconds later) and a sustained outage by HORCI (the downstream HORCI recloser remained open until crews could be mobilized to site).

- Protection systems registered a line-to-ground fault approximately 6-7 seconds after a 230 kV reactor at Pickle Lake TS was energized, causing WPLP's Line to Pickle Lake to trip, which resulted in a 30-minute outage to North Caribou Lake First Nation and Kingfisher Lake First Nation while switching was completed to restore the WPLP system.

C. 2022 Combined Reliability Performance

WPLP's 2022 reliability performance is summarized in the following table:[1]

All Causes:	
T-SAIFI	4.67
T-SAIDI (minutes)	1662.2
Average System Availability	99.6837%
Excluding Loss-of-Supply:	
T-SAIFI	3.67
T-SAIDI (minutes)	1626.8
Average System Availability	99.6905%
Excluding Loss-of-Supply and Planned Outages:	
T-SAIFI	1.67
T-SAIDI (minutes)	121.3
Average System Availability	99.9769%

The single largest driver of reliability performance in 2022 was planned outages related to construction. Two planned outages, with an average duration of 12.5 hours, were required for voltage conversion activity to prepare for the conversion of WPLP's Pikangikum Distribution System from 44 kV to 115 kV.

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[1] These transmission reliability metrics include outages on the Pikangikum Distribution System that occurred prior to its conversion to 115 kV.

Exhibit E, Tab 1, Schedule 1

Load and Revenue Forecasts

LOAD AND REVENUE FORECASTS

A. Operating Revenue

WPLP's forecasted 2024 operating revenue consists of revenue earned through the Network Uniform Transmission Rate (for the revenue requirement associated with the Line to Pickle Lake), and revenue earned through fixed monthly charges applicable to HORCI (for the revenue requirement associated with the Remote Connection Lines). Table 1 summarizes WPLP's 2024 revenue requirement, as calculated and allocated in Exhibit I.

Table 1 – 2024 Revenue Requirement Forecast

	LTPL	RCL	Total
Revenue Requirement for Rates	37,657,460	128,033,622	165,691,082

WPLP's 2023 approved revenue requirement is provided in Table 2. Absent any variations between actual and forecasted load, the differences in the amounts shown in Table 2 vs Table 1 represent WPLP's revenue deficiencies for the 2024 test year with respect to the Line to Pickle Lake and the Remote Connection Lines, and on an overall basis.

Table 2 – 2023 Approved Revenue Requirement

	LTPL	RCL	Total
Revenue Requirement for Rates	29,243,172	54,020,437	83,263,609

B. Load Forecast

As detailed in Exhibit I, WPLP's revenue requirement is allocated between the Line to Pickle Lake (for recovery through the UTR Network rate) and the Remote Connection Lines (for recovery through monthly fixed charges applicable to HORCI). For the purpose of UTR calculations, WPLP's load forecast therefore needs to consider the incremental network charge determinants related to its transmission system, but does not need to consider line connection or transformation connection charge determinants. The load supplied by WPLP's transmission system in 2024 will fall into three categories:

1. Some or all of the load currently supplied by HONI's transmission system in the Pickle Lake area, which will be supplied by WPLP's Line to Pickle Lake via a 115 kV interconnection between WPLP's Wataynikaneyap TS and HONI's new Pickle Lake SS;
2. Load on the distribution systems in the ten First Nation communities that will be connected to the North of Pickle Lake Remote Connection Lines for all or part of 2024, which will be supplied directly by WPLP's Transmission System; and,
3. Load on the distribution systems in the six First Nation communities that will be connected to the North of Red Lake Remote Connection Lines for all or part of 2024, which will be supplied directly by WPLP's Transmission System via HONI's transmission system, but is not included in HONI's UTR charge determinant forecast.

For the 2024 test year, the majority of the load supplied by WPLP's Transmission System will fall into the first category. Since these delivery points are all currently supplied by HONI, the associated charge determinants are not included in WPLP's load forecast as this would double-count the related charge determinants. To the extent that any of these loads increase over time as a result of the additional capacity enabled by WPLP's Line to Pickle Lake, WPLP expects that this will be considered in HONI's future charge determinant forecasts in the normal course of their transmission rate applications.

For the purpose of UTR calculations, WPLP's 2024 UTR Network charge determinants should therefore be limited to the second and third categories above, specifically the load associated with the sixteen First Nations that are expected to be connected to WPLP's Remote Connection Lines for all or part of 2024.

In lieu of developing a load forecast based on weather-normalized historical data (which WPLP does not have at this point in time), WPLP took the following approaches to forecast charge determinants:

1. WPLP requested recent historical peak demand data from HORCI for ten of the First Nations that are or will be supplied by WPLP's transmission system and are currently serviced by HORCI.[1] For these ten communities, this data was used, normalized to remove anomalies such as cold starts,[2] and with the peak demand for each month in 2024 escalated by 4% annually from the most recently available data. For the other six First Nations[3], WPLP used the peak load estimating process described in Approach 2, below.

2. WPLP used a combination of SIA forecasts and the monthly demand data from HORCI to forecast the monthly demand for the six First Nations currently not serviced by HORCI. Using annual peak demand forecast details from WPLP's SIA Application, which were informed by prior OPA and IESO data, WPLP first identified annual peak demand forecasts for these two communities. This data included a 4% annual growth rate, consistent with the expected level of growth identified in HORCI's 2018 backup power report.

   Using the historical demand data provided by HORCI for the other 10 First Nations, WPLP determined the average ratio of monthly demand to annual peak demand for the ten First Nations where historical monthly peak demand data was available and multiplied the annual demand forecast (from the SIA Application) for the other six First Nations by these ratios as a proxy for estimating the monthly demand for each month in 2024 that the load is expected to be in-service. The resulting demand forecast is provided in Table 3, and the

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[1] North Caribou Lake, Bearskin Lake, Sachigo Lake, Kingfisher Lake, Kasabonika Lake, Kitchenuhmaykoosib Inninuwug, Wapekeka, Pikangikum, Deer Lake, and Sandy Lake.

[2] Approximately 2% of the entries for the monthly peak demand by community obtained from HORCI also required estimation to resolve incomplete data. In these cases, WPLP estimated the missing peak demand values for 2022 by escalating the corresponding monthly peak demand from 2021, by the average of 2022 vs. 2021 peak demand increase for all other months for that community.

[3] Muskrat Dam, Wunnumin Lake, Wawakapewin, Poplar Hill, North Spirit Lake and Keewaywin.

total 2024 forecasted charge determinants of 156.2 MW is included in the UTR calculation in Exhibit I-3-1.

WPLP expects to develop a more robust load forecasting method as it acquires a suitable amount of historical consumption data for the grid-connected communities. For the 2024 test year, WPLP notes that its portion of the overall 2024 Network UTR charge determinants resulting from the above method is approximately 0.066%.

Table 3 – WPLP Peak Demand (MW) for UTR Charge Determinants

Delivery Point	2024 Annual Peak Forecast (MW)	**Forecast Demand by Month (MW)**												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
D - North Caribou Lake	1.5	1.0	1.2	1.5	1.1	1.0	0.8	0.9	0.8	0.9	1.1	1.2	1.2	12.9
E - Muskrat Dam	0.9	0.9	0.9	0.9	0.7	0.7	0.6	0.5	0.5	0.5	0.7	0.8	0.9	8.5
F - Bearskin Lake	0.9	0.9	0.9	0.7	0.7	0.7	0.6	0.5	0.5	0.5	0.6	0.8	0.9	8.2
G - Sachigo Lake	0.9	0.9	0.9	0.9	0.8	0.7	0.6	0.6	0.6	0.6	0.8	0.8	0.9	9.2
I - Wunnumin Lake	1.3	1.2	1.2	1.2	1.0	0.9	0.8	0.7	0.7	0.7	0.9	1.0	1.2	11.4
J - Kingfisher Lake	1.2	0.9	1.1	1.2	0.7	0.6	0.5	0.5	0.6	0.6	0.7	0.7	0.9	9.1
K - Wawakapewin	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	1.8
L - Kasabonika Lake	1.4	1.3	1.4	1.2	1.1	1.0	0.9	0.9	0.9	1.0	1.1	1.2	1.3	13.3
M - KI	*1.2*				*1.0*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*1.1*	*1.2*	*8.4*
M - Wapekeka	*1.3*				*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.7*	*1.0*	*1.2*	*1.3*	*8.3*
M - KI-Wapekeka Total	2.5				2.1	1.8	1.6	1.5	1.4	1.5	1.9	2.2	2.5	16.6
Pickle Lake Total	***10.0***	***7.2***	***7.8***	***7.8***	***8.3***	***7.6***	***6.5***	***6.3***	***6.0***	***6.6***	***7.9***	***8.9***	***10.0***	***90.9***
Q - Pikangikum	3.0	2.9	3.0	3.0	2.5	2.3	2.0	1.6	1.5	1.5	1.5	2.2	2.7	26.8
S - Poplar Hill	1.0				0.8	0.7	0.6	0.6	0.6	0.6	0.7	0.9	1.0	6.5
U - Deer Lake	1.5					1.0	0.9	0.8	0.7	0.8	1.1	1.3	1.5	8.2
V - North Spirit Lake	0.8							0.5	0.4	0.5	0.6	0.7	0.7	3.3
W - Sandy Lake	3.4						2.2	2.0	1.9	2.0	2.7	3.0	3.4	17.2
Y - Keewaywin	0.9								0.5	0.5	0.6	0.7	0.8	3.2
Red Lake Total	***10.2***	***2.9***	***3.0***	***3.0***	***3.3***	***4.1***	***5.8***	***5.5***	***5.6***	***5.9***	***7.2***	***8.8***	***10.2***	***65.3***
WPLP System Total	***20.1***	***10.1***	***10.8***	***10.8***	***11.6***	***11.7***	***12.3***	***11.8***	***11.6***	***12.5***	***15.1***	***17.7***	***20.1***	***156.2***

Exhibit E, Tab 2, Schedule 1

Accuracy of Load Forecast and Variance Analysis

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSIS

The following peak demand forecast for UTR charge determinants was included in the Settlement Agreement approved in EB-2021-0134:

Table 1 – WPLP Peak Demand (MW) for UTR Charge Determinants

Community	**Forecast Demand by Month (MW)**								
	Jan-May	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
North Caribou First Nation	-	0.9	0.9	0.8	0.9	1.0	1.1	1.1	6.8
Kingfisher Lake First Nation	-	0.5	0.5	0.5	0.5	0.6	0.7	0.7	4.1
Total	**-**	**1.4**	**1.4**	**1.3**	**1.4**	**1.6**	**1.8**	**1.9**	**10.9**

The actual peak demand values for 2022 and resulting variances between forecast and actual peak demand were as follows:

Community	**Forecast Demand by Month (MW)**								
	Jan-May	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
North Caribou First Nation	-	0.8	0.8	0.8	0.8	*1.0*	*1.1*	*1.1*	6.4
Kingfisher Lake First Nation	-	0.5	0.5	0.5	0.5	0.6	0.7	*0.8*	4.2
Total	**-**	**1.3**	**1.3**	**1.3**	**1.4**	**1.6**	**1.8**	**2.0**	**10.6**
Variance (MW)	**-**	**-0.1**	**-0.2**	**0.0**	**-0.1**	**0.0**	**0.0**	**0.1**	**-0.2**

For context, WPLP's 2022 OEB-approved Network UTR charge determinants represent 0.006% of the Ontario total.[1] As outlined in Exhibit E-1-1, WPLP expects to develop a more robust load forecasting method as it acquires a suitable amount of historical consumption data for the grid-

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[1] In its April 7, 2022 Decision and Order in EB-2022-0084, the OEB approved Network UTR determinants of 14.468 MW for WPLP (10.9 MW, annualized for a 12-month UTR calculation) and 239,002 MW for all transmitters combined.

connected communities. As illustrated above, variances resulting from WPLP's interim approach to load forecasting result in immaterial variances in the context of UTR calculations.

Exhibit E, Tab 3, Schedule 1

Other Revenue

OTHER REVENUE

WPLP is not forecasting any Other Revenues for the 2024 test year and expects that its 2024 revenues will consist solely of the transmission service revenues outlined in Exhibit E-1-1.

Exhibit F, Tab 1, Schedule 1

Operating Costs Overview

OPERATING COSTS OVERVIEW

WPLP’s operating costs for the 2024 test year include operations, maintenance and administration (OM&A); depreciation and amortization; and income taxes. A summary of WPLP’s operating costs for the 2024 test year is presented in Table 1 below.

Table 1 – Summary of Operating Costs

Operating Cost Category	2024 Test Year ($000's)
OM&A Expenses	30,984
Depreciation and Amortization	30,433
Income Taxes	502
Total Operating Costs	**61,919**

WPLP confirms that no charitable or political donations are included in its 2024 test year revenue requirement. Moreover, WPLP’s forecasted property tax expense is immaterial (less than $1,000) and is therefore included in the OM&A Expenses category instead of in a distinct property tax category.

This Exhibit provides forecasted costs for the 2024 test year, the 2023 bridge year and a variance analysis for the change in OM&A expense for the 2024 test year in respect of each of the 2023 bridge year and the 2022 historical year.

The Settlement Agreement in EB-2021-0134 required WPLP to file in its 2023 revenue requirement application two benchmarking studies to compare (i) WPLP’s OM&A spending levels on a per line kilometer basis and on a per station basis relative to comparable Ontario and Canadian transmitters, and (ii) WPLP’s compensation costs relative to Hydro One compensation costs.[1] Given the terms of the Settlement Agreement in EB-2022-0149, WPLP has not filed comparable studies in its rate application for 2024.

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[1] WPLP filed two benchmarking reports prepared by Clearspring Energy Advisors LLP in respect of the OM&A costs and by Korn Ferry in respect of compensation costs.

Pursuant to the Settlement Agreement in EB-2022-0149, WPLP also agreed to establish a new Construction Period OM&A Variance Account, effective January 1, 2023, to record the difference, if any, between forecast and actual OM&A expenses, with any shortfall in actual spending relative to the amounts approved in EB-2022-0149 to be returned to ratepayers in a future rate proceeding, over a 4-year disposition period (or shorter depending on materiality). WPLP is proposing to continue the Construction Period OM&A Variance Account for the 2024 test year. WPLP also agreed to file an economic benchmarking study of its OM&A costs in 2025 in respect of its application for approval of a transmission revenue requirement and rates for the period starting in 2026. WPLP expects that the econometric benchmarking study will help overcome the limitations identified in the unit cost benchmarking study that was filed in EB-2022-0149 by allowing appropriate adjustments for WPLP's unique business circumstances and transmission system characteristics.

Additional information for each item listed in Table 1 can be found as follows:

- OM&A – Exhibit F, Tab 2, Schedule 1 and Exhibit F, Tab 3, Schedule 1
- Depreciation and Amortization – Exhibit F, Tab 4, Schedule 1
- Income Taxes – Exhibit F, Tab 5, Schedule 1

Exhibit F, Tab 2, Schedule 1

Summary and Cost Driver Tables

OM&A SUMMARY AND COST DRIVER TABLES

A. Overview

This schedule provides a breakdown of WPLP's OM&A expenses for the 2024 test year along with a variance analysis for the change in OM&A expense for the 2024 test year in respect of each of the 2023 bridge year and the 2022 historical year.

B. OM&A Summary

WPLP's OM&A expenses include costs associated with the following activities:

- **Operation:** System control functions, inspection and operation of transmission station equipment, line patrols and inspections, and costs associated with land rights.
- **Maintenance:** Preventative maintenance programs designed to maintain asset health, corrective maintenance required to address deficiencies or deteriorating condition, including repairs of a non-capital nature during outages or other emergency conditions.
- **Administration & General:** Indigenous engagement, communications and participation, accounting, health, safety and environment, information technology, insurance, and general administration. Includes labour-related costs that are not specifically allocated to operation or maintenance activities.

WPLP's OM&A expenses are summarized in Table 1 below.

Table 1 – OM&A Expenses ($000's)

Category	**2022 Actuals**	**2023 Bridge Year**	**2024 Test Year**	**Variance 2023 to 2024**
Operations	1,318	5,533	10,814	5,281
Maintenance	-	2,890	5,231	2,341
Administration & General	2,638	11,451	14,939	3,488
Total OM&A	**3,956**	**19,874**	**30,984**	**11,110**

The increase in total OM&A from the 2023 bridge year to the 2024 test year is driven by: (1) the 2022 and 2023 in-service assets being in service for 12 months, (2) the addition of the 2024 in-service assets, and (3) a larger allocation of overhead costs to operations vs capital given that more assets will be in-service in 2024.[1] Due to the timing of assets coming into service in 2022 and the allocation method applied during construction period, the 2022 OM&A cost actuals should not be considered indicative of WPLP's OM&A forecasted figures in 2023 and 2024. Similarly, forecasted OM&A costs for 2023 and 2024 are not representative of WPLP's OM&A cost forecasts once project assets are entirely in service.

C. OM&A Cost Drivers

1. Summary of Cost Drivers

Table 2 below presents the cost drivers for each component of WPLP's 2024 OM&A expenses along with the associated variances.

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[1] The allocation of Overhead costs between capital and operations is outlined in Appendix 'A' of Exhibit B-1-5.

Table 2 – 2024 OM&A Cost Drivers

	Category of Expense	**2022 OM&A Actuals**	**2023 OM&A Budget[2]**	**2024 OM&A Cost Driver ($000's)**				**Variance**
				Operations	**Maintenance**	**Administration**	**Total**	
Direct Operating	Direct O&M Labour	0	317	904	904	0	**1,809**	**1,491**
	Controlling Authority (3rd Party)	294	3,120	2,355	0	0	**2,355**	**-765**
	Substation and Line Routine Maintenance	279	1,463	3,700	0	0	**3,700**	**2,237**
	Emergency Response and Reactive Maintenance	0	1,776	0	3,282	0	**3,282**	**1,506**
	Forestry	0	506	0	767	0	**767**	**261**
	Other (Material, Fleet, Insurance)	337	987	375	277	374	**1,026**	**39**
	Sub-Total	*909*	*8,169*	*7,334*	*5,231*	*374*	***12,939***	**4,770**
Overhead Costs Allocated to OM&A	Labour and Departmental Costs	1,893	5,899	1,725	0	6,535	**8,259**	**2,360**
	Environmental Services	48	230	244	0	0	**244**	**14**
	Other Consultants	116	588	732	0	726	**1,458**	**871**
	Indigenous Engagement & Communications	639	2,122	779	0	2,531	**3,310**	**1,188**
	Stakeholder Engagement	3	50	0	0	0	**0**	**-50**
	Indigenous Participation and Training	187	1,998	0	0	3,305	**3,305**	**1,307**
	Administrative Costs	141	818	0	0	1,469	**1,469**	**651**
	Sub-Total	*3,027*	11,705	*3,480*	*0*	*14,565*	***18,045***	**6,340**
Total		**3,937**	**19,874**	**10,814**	**5,231**	**14,939**	**30,984**	**11,110**

2. *Description of Cost Drivers*

This section describes the types of expenses included in Table 2 and provides variance analysis for the changes in OM&A expenses from the 2023 bridge year to the 2024 test year. A comparison to 2022 actuals is not considered valuable given the limited time assets were in service in 2022.

(a) Direct Operating Costs

WPLP's O&M strategy for the 2022-2024 period, during which time assets are being placed in service in stages but the overall project is still being constructed, is detailed in Section C of Exhibit B-1-4. Overall, Direct Operating costs are forecast to increase based on (i) the assets that went

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[2] 2023 budget was reduced per EB-2022-0149 settlement, where WPLP agreed to a 5% reduction in OM&A costs.

into service in 2022, are going into service in 2023, and which will therefore be in service for the entirety of 2024, and (ii) an additional 10 substations and approximately 555 km of transmission lines that will be put into service in 2024. The increases are partially offset by a reduction for costs for SCADA and control room services to reflect the executed control room services agreement with HONI and the timing of in-service assets forecasted for 2024. Based on WPLP's O&M strategy, executed IMER Services Agreement and using a bottom-up forecasting approach, WPLP has forecast direct operating costs for the 2024 Test Year as follows:

- Approximately $1.8 million for operations staff managing in-service assets and managing third-party agreements including HONI control room services and executed IMER Services Agreement.

- Approximately $2.36 million related to third-party control room operation, which is based on a unit cost estimate for HONI to provide control room services for WPLP substation assets and related control points expected to be in-service. WPLP has reached an agreement with Hydro One Networks Inc. to provide control room services for an interim period until such time that WPLP develops its own control room.

- Approximately $3.3 million for outage and emergency response, plus $3.7 million related to routine line and substation inspection and maintenance activities and $0.8 million for forestry costs, for assets expected to be in service throughout 2024 as well as assets coming in to service in 2024. These costs are based on pricing within the IMER Services Agreement and anticipated emergency provision based on T&M rates. The IMER services include planned inspections of transmission line and substation assets, substation equipment testing and maintenance, and response to power outages and other emergencies.

- Approximately $1 million for other costs that include fleet and insurance costs for operations staff (gas, insurance premiums, communication services, software subscriptions, general maintenance and repairs) as well as a provision for materials issued from inventory during the performance of outage and emergency response.

(b) Overhead Cost Allocated to OM&A

As set out in Table 2, above, WPLP's overhead costs include costs such as internal labour and departmental costs,[3] services provided by environmental and other third-party consultants and professionals, costs related to continued Indigenous engagement and communications, Indigenous participation and training, stakeholder engagement and general administrative costs.

As the construction phase of WPLP's Transmission Project progresses and assets come into service during the 2022-2024 period, a progressively larger portion of these overhead costs transitions from being directly attributable to capital development and construction activity to being attributable to the ongoing operation and maintenance of in-service assets. Accordingly, WPLP developed a methodology to allocate these costs between capital and OM&A, which is described in detail in Appendix 'A' of Exhibit B-1-5. Applying the allocation methodology to WPLP's 2024 forecasted overhead costs results in the following 2023 forecast for OM&A costs:

- Approximately $8.3 million for labour costs[4], including related overheads, for WPLP's internal staff, whose focus will shift from construction of the Transmission Project to ongoing operations and maintenance of the transmission system as more assets come into service. Also includes land rents of $1.7 million shown in operating column.

- Approximately $0.24 million for environmental and other consultants that provide services and expertise in a wide variety of areas (e.g. environmental services, legal/regulatory, finance/audit, engineering, etc.).

- Approximately $3.3 million for Indigenous engagement and communications and stakeholder engagement, and $3.3 million for Indigenous participation and training. These activities relate to WPLP's comprehensive Indigenous Engagement Program and Indigenous Communications Management Plan (which are summarized in Exhibit B-1-2),

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[3] For clarity, any labour for WPLP operations staff that is included in the forecast of direct O&M costs under part (a) is excluded from the internal labour costs under overhead costs in part (b).

[4] Further detail on labour costs provided in Exhibit F-3-1.

meaningful economic participation by Indigenous businesses in all aspects of the Transmission Project, consultations with stakeholders (such as municipalities and potentially affected landowners), and overall project communications activities. As assets come into service, continued efforts in these areas will ensure that WPLP's transmission system is operated in a manner that respects the Guiding Principles, Aboriginal and Treaty, and Inherent rights of the Anishinabe and Anishinninuwug, and that considers input from other stakeholders.

- Approximately $1.5 million for general administrative costs including non-capital costs related to office space, fleet and insurance premiums for management staff, as well as executive and board of director oversight.

Exhibit F, Tab 3, Schedule 1

Program Delivery Costs with Variance Analysis

PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

This Schedule provides a breakdown of WPLP's OM&A expenses for the 2024 test year, which reflects the categorization in Section 2.8.3 of the Filing Requirements. WPLP's OM&A expenses, aggregated according to those categories, are summarized in Table 1 below and described in detail in Sections A through F of this Schedule.

Table 1 – OM&A Expenses by Program

OM&A Expense Category	2024 Test Year ($000's)
Employee compensation	4,850
Shared services and corporate cost allocation	4,608
Purchase of non-affiliate services	21,526
One-time costs	0
OEB costs	0
Charitable and political donations	0
Total	**30,984**

The total OM&A expense in Table 1 above is equal to and reflects the same amounts as are included in the total 2024 test year OM&A expenses presented in Exhibit F-2-1. However, Table 1 above categorizes those amounts differently by considering OM&A expenses according to the nature or sources of such costs, as opposed to the activity/cost driver-based categorization in Exhibit F-2-1.

As described in Exhibit B-1-4, Wataynikaneyap Power PM Inc. ("WPPM") has the responsibility to develop, construct and operate the Transmission Project through a Management Agreement with WPLP. WPPM provides these services in part through the use of dedicated staff that are employed directly by WPPM. Since these compensation costs are billed to WPLP at cost, the discussion of employee compensation in Section A below includes details of employee compensation related to WPPM employees.

Services are also provided under service agreements by parties related to WPLP, including Opiikapawiin Services LP ("OSLP") and FortisOntario Inc. These services are billed according to pre-determined schedules of hourly rates, which reflect market pricing, and are detailed in Section B (Shared Services and Corporate Cost Allocation).

WPLP's rationale for distinguishing employee compensation costs in Section A as compared to shared services in Section B relates to the manner in which the costs are incurred, in an effort to align the categorization with Sections 2.8.4 and 2.8.5 of the Filing Requirements. Both categories of costs are equally important to the successful completion of WPLP's Transmission Project and to the ongoing operation of WPLP's Transmission System.

Any costs originating from third parties (i.e. parties that are not affiliates of or related to WPLP or one of its partners) are detailed in Section C (Purchase of Non-Affiliate Services), including any such third-party costs that are incurred by affiliated or related parties and passed through to WPLP (without markup).

The rationale for not segregating one-time and regulatory costs for amortization over a multi-year period is provided in Sections D and E below, and WPLP confirms in Section F that its revenue requirement includes no amounts for charitable or political donations.

A. Employee Compensation

This section provides an overview of WPPM's compensation framework, including an outline of WPPM's approach to employee benefits and incentive pay, as well as WPLP's approach to benchmarking its compensation costs to other utilities. WPLP has a single direct employee, being the Chief Executive Officer, as described below. The discussion of WPPM's compensation framework in this section therefore does not apply to WPLP's CEO.[1] The breakdown of total

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[1] Because there is a single direct employee for WPLP, a description of the compensation for that position is not provided. In accordance with Section 2.8.4 of the Filing Requirements "where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related". As such, the total compensation costs for WPLP's CEO are included in the "Management (including executive)" rows of Table 2 at the end of this section, notwithstanding that the details of the compensation framework described below are not applicable to this position.

forecasted employee compensation costs to December 31, 2024 in Table 2 is provided in a format consistent with Appendix 2-K (Employee Costs) of the OEB's Chapter 2 Appendices.

Employee compensation costs for WPLP and WPPM relate to the following functions and departments:

- Executive oversight for WPLP, provided by the Chief Executive Officer of WPLP;
- Health and safety, environmental compliance, construction oversight, project management, engineering and operations, under the direction of the Chief Operating Officer of WPPM;
- Finance, audit, risk management, regulatory and procurement, under the direction of the VP Finance and CFO of WPPM; and
- Corporate services, including HR, IT, legal, administrative support and WPPM's participation in the various recruitment, training, engagement and communication activities that are coordinated by OSLP, under the direction of the VP Corporate Services and Indigenous Relations of WPPM.

1. Base Pay Compensation

Overall compensation for WPPM employees is designed to remain competitive with market compensation to attract and retain qualified personnel. Overall compensation includes base pay and a portion of the pay which is at risk. WPLP follows the process outlined below in establishing and making changes to employee compensation.

WPPM uses Korn Ferry's Job Evaluation method for position evaluation. This method of job evaluation is the most widely used job measurement system in the world. Position evaluations for the WPPM Executive positions were established by Korn Ferry. Management and Non-Union employee positions are either evaluated by Korn Ferry, by internal staff trained on job evaluation, or assigned to job classes within the Korn Ferry evaluation system based on similar evaluations completed previously. WPPM does not have any unionized employees.

WPPM uses a reference group of participants in the Korn Ferry Compensation Comparison. This reference group is used to establish the market rates for similar positions in Ontario. To attract and retain qualified staff, WPPM sets midpoint salaries using a policy line recommended by Korn Ferry management consultants. Actual salaries are set by reference to these recommendations and based on corporate and individual performance.

For members of the WPPM Executive, the WPPM Board of Directors considers Korn Ferry compensation data and other policies to validate that the compensation practices are market competitive. All Executive salaries are set and all increases must be approved by the WPPM Board of Directors.[2]

Salary increases for all WPPM employees are based on market information provided by Korn Ferry. The resulting salaries are reflective of base compensation for similar positions in Ontario. All salaries are approved by senior management and/or the WPPM Board of Directors, as applicable.

2. Incentive Compensation

(a) Description

Another element of the overall WPPM employee compensation package is incentive compensation. Implicit in the analysis contained in Korn Ferry's recommendations is the fact that incentive compensation is a normal component of compensation for management positions in Canadian corporations.

Incentive compensation for all WPPM employees reflects an element of compensation put at risk to elicit and sustain continued good performance. The more senior the employee, the greater the percentage of overall compensation that is put at risk.

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[2] As noted above, this discussion applies to WPPM and this discussion of WPPM Executive compensation excludes the CEO of WPLP.

(b) Format

A short-term incentive ("STI") plan includes both an individual and a corporate component for all WPPM employees. Key aspects of this plan together with the targets are outlined below.

(i) Minimum Corporate Performance Criterion

Prior to any incentive payments being made, a minimum corporate performance criterion, or trigger, must be reached. WPPM must achieve a pre-determined corporate threshold/target as approved by the WPPM Board of Directors; otherwise, no incentive payments will be made.

(ii) Corporate Targets

WPPM's corporate targets may relate to the following: cost control, capital project completion, customer service, quality of construction, OM&A management, reliability, safety and environment and regulatory compliance, and are expected to shift as WPLP's focus transitions from construction to ongoing operation. Accordingly, all corporate incentive payments included in WPLP's compensation costs presented in Table 2 benefit ratepayers as described below. Corporate measures have three performance levels and are reflective of key corporate targets or goals.

Each of the corporate targets benefit ratepayers. In particular, the cost control measure sets targets for reducing operating costs. The capital project measure sets targets for meeting budgeted capital project costs and completing construction of the project with respect to scope and schedule. These measures are primarily customer related as they represent a cost control target. Customer service corporate measures ensure efficient and effective levels of service that meet OEB standards and service quality indices. Safety and environmental measures benefit ratepayers by minimizing high risk incidents and promoting a proactive approach to managing safety and the environment. Regulatory compliance benefits ratepayers as it helps ensure a reliable supply of electricity and a high quality of customer service at reasonable rates.

(iii) Individual Targets

Individual targets, like the corporate targets, support the broader design objective of aligning the interests of all stakeholder groups with an overall focus on efficient delivery of service to customers.

Individual measures are developed in consultation with individuals and their immediate superiors. Each measure has three performance levels, is reflective of key projects or goals and focuses on departmental or divisional priorities. Individual measures may relate to the following: human resources, safety and environment, reliability, regulatory compliance, customer service, efficiencies, capital project completion, cost reduction and training targets. These measures primarily benefit ratepayers for the reasons discussed herein. Human Resources primarily benefit ratepayers by ensuring that skilled personnel are recruited and retained to provide safe and reliable service and to maintain service levels. Cost reduction, capital project completion and efficiency measures relate to maintaining or reducing operating costs, which directly impact ratepayers through rates. Safety and environment, training, reliability, regulatory compliance and customer service measures directly benefit ratepayers by incenting employees to contribute to the delivery of a safe and reliable supply of electricity in compliance with regulations and established customer service levels.

(iv) Payout Structure

WPPM’s STI payouts are based on a percentage of annual salary and range between 7.5% and 35%, depending on position. WPPM’s STI objectives and targets are set annually and establish criteria upon which the corporation’s performance and individual performance are measured, as discussed above. The objectives are then scored, which results in an STI rating between 0% and 200%.

The individual performance component is designed to reflect the degree of opportunity which employees in each management group have to influence corporate performance. The weighting for the individual component varies by position level and ranges between 30% and 75%. The balance of the weighting is based on a corporate STI scorecard approved annually by the WPPM Board of Directors.

The incentive regime is structured in a manner that emphasizes the greater ability of more senior individuals to impact corporate performance by making a greater portion of their compensation dependent on corporate, as opposed to individual, performance.

(c) Assessment and Payment

The WPPM Board of Directors approves the corporate targets for all participants and the individual targets for Executives. The corporate component is reflective of key corporate targets or goals and WPPM's actual performance against those targets is assessed and approved annually by the WPPM Board of Directors. Actual performance against individual targets is evaluated by each individual's immediate superior. Payments are generally made in February, once all corporate and individual performance measures for the relevant financial year have been finalized. WPPM budgets for incentive payments at target payment levels.

3. Pension and Post-Retirement Benefits Expense

WPPM employees are eligible to participate in a Defined Contribution Pension Plan, where the Company generally matches employee contributions up to 6.5% of base pay. Employer contributions to the Defined Contribution Pension Plan are included in the Total Benefits amounts provided in Section 5 below.

4. Other Benefits

Other benefits include the employer portion of Canadian Pension Plan contributions, the employer portion of Employment Insurance expense, Employee Health Tax expense, WSIB expense, insurance benefit, extended health and dental care plan expense, share purchase plan expenses, wellness reimbursements and employee assistance plan services.

5. Staffing Levels and Total Compensation

WPPM initially began recruitment with a significant number of leadership positions to create the framework for the company. WPPM has since grown to 27 employees including a number of non-management positions which has balanced the management to non-management ratio to 12:15. The company is projected to grow to 35 (13:22) employees by the end of 2023 and remain at 35 (13:22) by the end of 2024 with expected changes to FTE positions from construction to operations. The largest driver of FTE growth is related to Operations Management and Engineering positions, which are required to ensure effective implementation and oversight of WPLP's O&M Strategy as discussed in Exhibit B-1-4[3].

WPPM's FTEs now include an increased number of operational positions, which utilize the Korn Ferry methodology to determine appropriate rates for compensation. Given the nature of the organization and the focus on the construction of the transmission line, some positions had to be uniquely designed to meet the qualifications of the candidates. Due to the difficulty in recruiting experienced project candidates with a utility background, WPPM has had to modify some position expectations.

WPPM had to become more flexible with the structure of positions as a result to build a strong team to lead the organization through construction and beyond. Standard 'utility positions' didn't always fit the requirement for the position or the candidate. These positions are often unique in nature and do not always have comparable positions within the industry. These positions have been evaluated based on Korn Ferry's Hay methodology to ensure compensation is appropriate for the job expectations.

A breakdown of total forecasted employee compensation costs to December 31, 2024 is provided in Table 2, below.

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[3] Additional positions in 2023 include 2 administrative assistants, Operations Coordinator – Stations, Operations Coordinator – Lines, Forestry Management Coordinator, P&C Engineer, Operations Technician, and Manager Project Relations. Additional hirings in 2024 include additional administrative assistant offset by one contract position being eliminated.

Table 2: Employee Compensation Breakdown

	2020 Actual	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
Number of Employees (FTEs including Part-Time)					
Management (including executive)	8	12	12	13	13
Non-Management (all non-union)	9	14	15	22	22
Total	**17**	**26**	**27**	**35**	**35**
Total Salary and Wages including overtime and incentive pay					
Management (including executive)	$1,992,257	$2,335,708	$2,735,577	$3,168,615	$2,752,294
Non-Management (all non-union)	$687,504	$912,428	$1,327,607	$2,273,005	$2,187,302
Total	**$2,679,761**	**$3,248,136**	**$4,063,184**	**$5,441,619**	**$4,939,596**
Total Benefits (Current + Accrued)					
Management (including executive)	$223,906	$317,038	$357,246	$483,348	$419,841
Non-Management (all non-union)	$68,633	$127,338	$205,631	$346,730	$333,656
Total	**$292,539**	**$444,376**	**$562,876**	**$830,078**	**$753,498**
Total Compensation (Salary, Wages, & Benefits)					
Management (including executive)	$2,216,163	$2,652,746	$3,092,823	$3,651,963	$3,172,135
Non-Management (all non-union)	$756,136	$1,039,766	$1,533,238	$2,619,734	$2,520,958
Total	**$2,972,300**	**$3,692,512**	**$4,626,060**	**$6,271,697**	**$5,693,093**
Total Allocated to Capital	$2,876,746	$3,549,118	$3,755,747	$3,061,654	$843,471
Total Allocated to Distribution Deferral Account (Pikangikum)	$95,554	$143,394	$118,942	-	-
Total Allocated to OM&A	-	-	$751,371	$3,210,043	$4,849,622

6. Variance Analysis

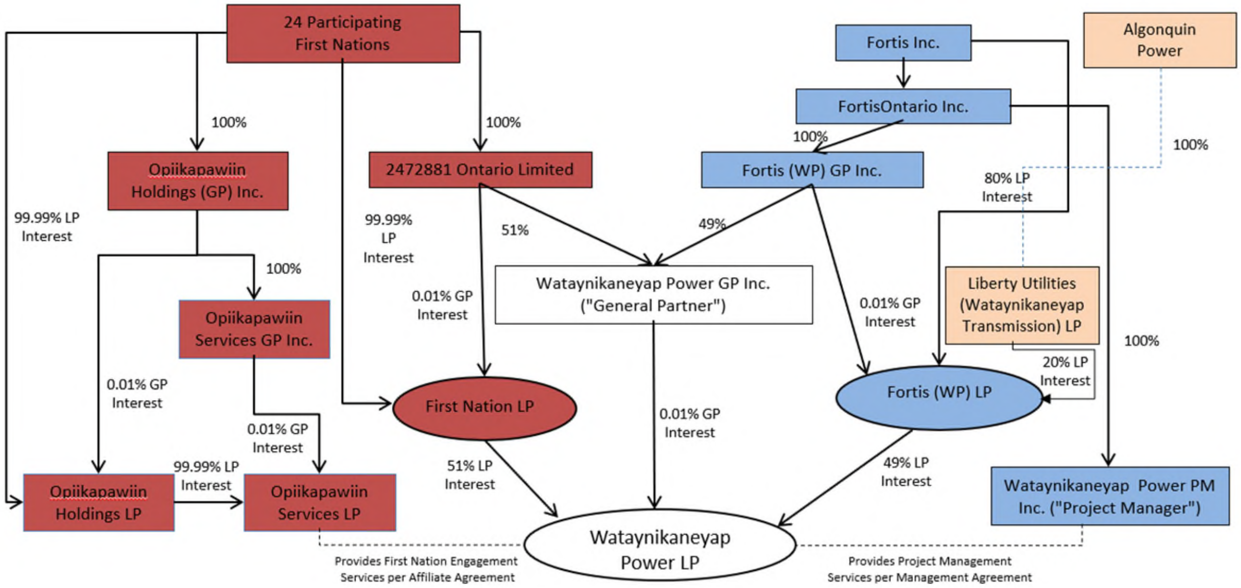
Employee compensation costs are increasing primarily due to actual and forecasted WPPM employee hiring to support WPLP's transition from constructing the Transmission Project to long-term operation of its transmission system. A description of WPLP's approach to the organization and execution of the construction period, and the transition to ongoing operation and maintenance, is provided in Exhibit B-1-4. Some salaries appear higher than industry norm as they are short-term construction contracts that require specific skills set for the duration of the construction period. In order to attract and retain these employees, WPPM has to rely on the market for salary references to remain competitive and secure employees for the duration of the project.

Table 2, above, also illustrates a shift from labour costs being primarily capitalized during the construction period, to increasing allocations to OM&A as assets come into service in 2023 and 2024. WPLP's methodology supporting the declining labour capitalization rate is provided in Appendix 'A' of Exhibit B-1-5.

B. Shared Services and Corporate Cost Allocation

This section provides details of the services that WPLP receives from affiliates and other related parties. WPLP's corporate structure is described in detail in Exhibit A-4-1, and is reproduced in Figure 1 below, with the addition of affiliated and related entities that provides services to WPLP.

Figure 1 – WPLP Corporate Structure with Affiliated/Related Service Providers



WPLP manages the construction of the Transmission Project and will manage the operation of its transmission system, primarily through services received by affiliated and related parties, through the service agreements described below. While the costs resulting from these agreements are not strictly related to "shared services" or "corporate cost allocation", as those terms are defined in Section 2.8.5 of the OEB's Filing Requirements, WPLP has used this section to summarize annual costs from affiliated and related parties that are not otherwise captured in Section A (Employee Compensation) above or Section C (Purchase of Non-Affiliate Services) below.

1. Service Agreements

WPLP receives services from affiliated and related parties through the following agreements:

- **Affiliate Contract (OSLP):** Opiikapawiin Services LP ("OSLP"), a service company indirectly owned by the 24 Participating First Nations, is responsible for administering projects and programs for WPLP relating to community engagement, community readiness, education and training, business readiness, stakeholder engagement, communications, and capacity building, pursuant to an Affiliate Contract between WPLP and OSLP. OSLP is an affiliate of WPLP because they are both under the common control of the Participating First Nations. Additional information about OSLP is provided in Exhibit B-1-4.

- **Management Agreement (WPPM):** Wataynikaneyap Power PM Inc. ("WPPM"), a wholly-owned subsidiary of FortisOntario Inc., is responsible for providing project management, construction oversight, engineering, operations, finance, regulatory and various corporate service functions (including health and safety, environmental compliance, HR, IT and procurement), pursuant to a Management Agreement between WPLP and WPPM. WPPM is a related party but is not an affiliate of WPLP.

- **Services Contract (FortisOntario):** FortisOntario Inc. provides similar but distinct complementary services as provided by WPPM under the Management Agreement, pursuant to a Services Contract between WPLP and FortisOntario Inc. FortisOntario is a related party but is not an affiliate of WPLP.

The pricing structure for the agreements includes a base annual fee, as well as reimbursement for direct costs and amounts paid to third parties (without markup). Where services are provided by WPPM employees to WPLP under the Management Agreement, these services are provided at cost, consistent with the compensation-related discussion in Section A above. Where services are provided by employees of OSLP or FortisOntario, these amounts are billed according to a pre-determined schedule of hourly rates for various positions and levels of seniority, which reflects market pricing.

2. Summary of Costs from Affiliated and Related Parties

Table 3 summarizes the costs charged to WPLP from affiliates and related parties, excluding third-party costs incurred by those parties which are addressed in Section C:

- OSLP, which costs are primarily related to labour charges and related costs for the services provided under the Affiliate Agreement described above; and

- FortisOntario, which costs are primarily related to labour charges and related costs for the services provided under the Services Contract described above, including costs for employees of various Fortis Inc. subsidiaries other than WPPM that are indirectly charged to WPLP through time allocations.

OSLP and WPPM also procure services from third parties on behalf of WPLP, and are reimbursed by WPLP, without markup. These third-party costs are excluded from the costs presented in Table 3 since they are addressed in Section C below. Compensation costs for employees directly employed by WPPM are also excluded since they are addressed in Section A above.

Table 3 – Affiliate and Related Party Costs by Year[4]

Name of Company		**Service Offered**	**Cost for the Service ($)**				
From	**To**		**2020**	**2021**	**2022**	**2023**	**2024**
			Actual	**Actual**	**Actual**	**Forecast**	**Forecast**
Fortis Subsidiaries	WPLP	Multiple per Services Contract	1,860,578	1,705,252	1,745,527	2,165,038	2,208,339
OSLP and FNLP	WPLP	Multiple per Affiliate Contract	2,682,315	2,822,838	2,885,790	3,344,400	3,049,200
Total:			**4,542,893**	**4,528,090**	**4,631,318**	**5,509,438**	**5,257,539**

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[4] Costs related to COVID-19 are minimal and are not tracked separately.

Affiliate costs are trending down and WPLP will continue to focus on cost savings as we transition from capital project construction to operations.

Table 4, below, summarizes the annual allocation of the costs presented in Table 3 between: (a) capital costs (development and CWIP); (b) costs related to the interim operation of WPLP's Pikangikum distribution system (recorded in WPLP's Distribution System Deferral Account); and (c) OM&A costs associated with transmission system assets in service or coming into service in 2023 and 2024.

Table 4 – Allocation of Affiliate and Related Party Costs[5]

Cost Category	**Annual Cost Allocation ($)**				
	2020	**2021**	**2022**	**2023**	**2024**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**
Capital	4,423,161	4,434,098	3,930,740	2,549,493	649,306
Distribution Deferral Acct (Pikangikum)	119,731	93,992	109,163	-	-
OM&A	-	-	591,416	2,959,946	4,608,233
Total	**4,542,893**	**4,528,090**	**4,631,318**	**5,509,438**	**5,257,539**

WPLP's methodology for allocating overhead costs, including the affiliate and related party costs presented above, is detailed in Appendix 'A' of Exhibit B-1-5. Support for the resulting capital, deferral account and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-5.
- Deferral Account costs are described in Exhibit H-2-1.
- OM&A costs, by cost driver, are described in Exhibit F-2-1.

C. Purchase of Non-Affiliate Services

This section describes WPLP's purchase of services from third parties, including third-party services procured directly by WPLP (administered by WPPM) and third-party services procured

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[5] Costs related to COVID-19 are minimal and are not tracked separately.

by OSLP, WPPM or FortisOntario Inc. on behalf of WPLP with the associated costs being passed through to WPLP without markup.

WPLP's procurement policy is based on the concept of securing "best value" in the procurement of goods and/or services from non-affiliated parties. In consideration of the remote location of WPLP's transmission system, local knowledge is critical to the successful delivery of any services. Supporting local opportunities and capacity to provide services will provide long-term benefits to WPLP, and the customers in the Indigenous communities that it serves. From a procurement perspective, best value must therefore include considerations such as local knowledge, use of local content, First Nation ownership, health and safety, reliability, price, quality, service and support levels, environmental performance, and timely delivery. In all cases, suppliers of goods and providers of services must be appropriately qualified in consideration of qualifications and standards regularly employed by transmission facility owners. A copy of WPLP's Procurement Policy is provided as Appendix 'A' to this schedule.

As described in Section B above, WPPM provides services to WPLP under a Management Agreement, which include project management, construction oversight, operational services and various corporate services. These services include the use of third-party services, which are procured in accordance with WPPM's Procurement Policy and in adherence to WPLP's Procurement Policy. A copy of WPPM's Procurement Policy, with supporting documents and policies, is provided as Appendix 'B' to this schedule.

In order to ensure best value in procurement, the procurement policies referenced above set out requirements for Indigenous participation, Participating First Nation involvement, local content, safety, quality, price and reliability, among other considerations. Further, the procurement policies prescribe requirements for competitive sourcing of goods and services, with limited exceptions, and describe approval levels and processes.

Table 5, below, provides a summary of WPLP's annual non-EPC[6] costs related to the purchase of goods and services from third parties, which WPLP confirms to be in compliance with WPLP's and WPPM's procurement policies.

Table 5 – Third-Party Costs by Year[7]

Cost Category	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Aboriginal Engagement, Indigenous Participation, Communication	2,625,177	2,393,026	2,961,282	4,778,475	5,129,634
Admin, Office, Fleet and Support	420,263	378,735	1,107,051	1,653,338	1,729,428
O&M Service Providers	275,363	805,437	1,658,216	7,005,936	10,111,773
Overheads and Easement/Access Fees	1,020,513	920,430	2,858,659	4,307,176	4,587,364
Consulting, Professional and Advisory	11,461,485	13,347,675	11,786,940	13,155,456	11,074,439
Total	**15,802,801**	**17,845,302**	**20,372,148**	**30,900,381**	**32,632,638**

Table 6, below, summarizes the annual allocation of the costs presented in Table 5 between: (a) capital costs (development and CWIP); (b) costs related the interim operation of WPLP's Pikangikum distribution system (recorded in WPLP's Distribution System Deferral Account); and (c) OM&A costs for transmission system assets in service or coming into service in 2023 and 2024.

Table 6 – Allocation of Third-Party Costs[8]

Cost Category	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Capital	15,318,440	16,899,726	16,308,061	17,196,371	11,106,807
Distribution Deferral Acct (Pikangikum)	484,360	945,576	1,450,370	-	-
OM&A	-	-	2,613,717	13,704,011	21,525,831
Total	**15,802,801**	**17,845,302**	**20,372,148**	**30,900,381**	**32,632,638**

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[6] The costs presented in this Schedule exclude the following capital costs from Exhibit B-1-5: (a) EPC contract costs (see Exhibit B-1-2 for details of competitive tendering and selection process); (b) "EPC Excluded" capital costs (which relate to the EPC contracting effort, but are excluded from the EPC contractor's responsibility); (c) "Other Infrastructure" costs (most of which are forecasted for 2023); and (d) contingency allowance.

[7] Costs related to COVID-19 are minimal and are not tracked separately, and are recorded as capital.

[8] Costs related to COVID-19 are minimal and are not tracked separately, and are recorded as capital.

WPLP's methodology for allocating overhead costs, including the affiliate and related party costs presented above, is detailed in Appendix 'A' of Exhibit B-1-5. Support for the resulting capital, deferral account and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-5.
- Deferral Account costs are described in Exhibit H-2-1.
- OM&A costs, by cost driver, are described in Exhibit F-2-1.

D. One-Time Costs

WPLP has filed a single test-year application for 2024 and anticipates filing an additional single-year cost of service revenue requirement application for the 2025 test year, as noted in Exhibit A-2-1. Accordingly, there is no need in the current application to amortize any one-time costs over any incentive rate setting period.

E. Regulatory Costs

WPLP's anticipated regulatory costs associated with the current application, are part of its total forecasted Transmission Project costs to December 31, 2024, which are described in Exhibit B-1-5. WPLP has included its costs for OEB assessment in the current application, in the amount of $16,000. In the forecasted 2024 OM&A expenses, WPLP has included the single-year cost of service revenue requirement application that WPLP anticipates filing for the 2025 test year in 2024. The anticipated costs for filing has estimated costs of $393,300. As this would be a single test year application, there is no need in the current application to amortize those regulatory costs over any incentive rate setting period.

F. Charitable and Political Donations

WPLP confirms that no charitable or political donations have been included in the calculation of its revenue requirement.[9]

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[9] WPLP anticipates making donations in the 2024 test year, but such donations have not been included in this application and are not expenses when determining the OM&A Variance amount. In the 2023 test year, WPLP anticipates paying $50,000 in charitable donations.

APPENDIX ‘A’

WPLP Procurement Policy

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WATAYNIKANEYAP PROCUREMENT POLICY

GENERAL STATEMENT

In the provision of services to First Nation communities and the public as an electricity transmitter, Wataynikaneyap shall engage in the procurement of goods and services.

As of June 2018, twenty-two First Nations are acting together to develop the Project through First Nations LP, and have set out Guiding Principles for development, which principles include the right of Participating First Nations to pursue sustainable economic and business opportunities in their homelands, for the benefit of their future generations and as part of a long term vision to secure opportunities from the lands and resources, pursue economic development and energy while protecting the environment, and maintain their peoples' responsibilities to the land as given by the Creator.

Given the significant challenges faced by Participating First Nations due to their remote locations, lack of access to reliable power, and the ongoing legacy of the residential schools system and the *Indian Act*, specific measures are required in order to ensure Participating First Nations have opportunities to compete for business opportunities.

This Procurement Policy sets out specific measures that will ensure business opportunities are readily available for Participating First Nations, and measures to ensure uniformity, best value, efficiency and effectiveness in the acquisition of goods and services.

1. DEFINITIONS AND PURPOSES

1.1. For the purposes of this Procurement Policy:

a) **"Best Value"** means a demonstration of the merits of any particular bid, proposal or offer of goods and/or services to Wataynikaneyap, as against the merits any reasonably-available alternatives. A determination of Best Value shall be arrived at by weighing considerations such as: local knowledge (including demonstrated history of the ability to provide reliable service or supply of goods with an indigenous workforce, and ability to speak Ojibwaymowin and Anishiniinimowin), use of local content (including labour, equipment, material and training), Participating First Nation ownership and control, health and safety, reliability, price, quality, service and support levels, environmental performance, and timely delivery;

b) **"Competitive Procurement Process"** means a tender, request for proposals or any other similar procurement process;

c) "**First Nations Business**" means a business, joint venture or consortium that is at least 51 per cent owned and controlled, directly or indirectly, by one or more Participating First Nation(s);

d) **"First Nations LP"** means the limited partnership which has a 51% majority and controlling ownership interest in Wataynikaneyap;

e) **"Fortis"** means Fortis Ontario Inc., a, electricity and gas utility company which holds a 49% ownership interest in Wataynikaneyap;

f) **"Guiding Principles"** means the document approved by the Participating First Nations which sets out guiding principles for the Project;

g) **"Indigenous Participation KPIs"** means the following key performance indicators:

   i. number of Individual Members that are employees, and percentage of the workforce that this represents;

   ii. number of employees that speak Ojibwaymowin and Anishiniinimowin, and percentage of workforce that this represents;

   iii. number of Individual Members in management, supervisory or leadership roles;

   iv. dollar value of spend with First Nations Businesses and Individual Member Businesses, and percentage of total spend that this represents; and

   v. number of Individual Members participating in education, training or entrepreneurship program(s) or other capacity development initiatives;

h) **"Indigenous Participation Target"** means the 5-year development plan prepared by Wataynikaneyap and Participating First Nations in accordance with section 4.2 of this Procurement Policy, with annual revenue targets for working with and providing opportunities to First Nation Businesses either directly or through contractors and subcontractors;

i) "**Individual Member**" means an individual band member of a Participating First Nation;

j) **“Individual Member Business”** means a business, joint venture or consortium that is at least 51 per cent owned and controlled, directly or indirectly, by one or more Individual Member(s);

k) **“Indigenous Participation Plan”** means the plan that all participants in Competitive Procurement Processes shall prepare in accordance with section 4.9 and Appendix A of this Procurement Policy;

l) **“Participating First Nations”** means the First Nations that are limited partners in First Nations LP;

m) **“Price Preference”** has the meaning set out in section 4.7(g);

n) **“Priority”** is used in Competitive Procurement Processes, and means that where two or more participants are reasonably comparable, the participant with Priority shall be awarded the contract;

o) **“Procedures Manual”** is the manual setting out the procedures by which Wataynikaneyap will implement this Procurement Policy;

p) **“Project”** means a new regional electricity transmission system in northwestern Ontario to connect 17 remote First Nations currently powered by diesel generation to the provincial electrical grid;

q) **“Registry”** means a database under the care and control of Wataynikaneyap which identifies First Nations Businesses that are interested in working on or in relation to the Project, and their capabilities;

r) **“Shareholders Agreement”** means the unanimous shareholders agreement dated August 27, 2015 between the general partners of Wataynikaneyap, Fortis and First Nations LP regarding the governance and control of Wataynikaneyap; and

s) **“Wataynikaneyap”** means Wataynikaneyap Power LP, an Ontario limited partnership established for the purposes of developing, constructing, owning and operating the Project.

1.2. The purposes of this policy are:

a) to ensure procurement activities provide opportunities for First Nations Businesses and Individual Member Businesses, and facilitate education, training, meaningful employment and capacity-building for Individual Members;

b) to ensure prices paid are reasonable in the circumstances; and

c) to standardize procurement processes.

2. GENERAL PRINCIPLES

2.1. Procurement processes shall provide sustainable economic and business opportunities for First Nations Businesses and Individual Member Businesses.

2.2. Procurement processes shall be conducted with diligence and care, and ensure that all relevant information is obtained and considered.

2.3. All procurement decisions shall be reasonable under the circumstances known to Wataynikaneyap at the time the decision is made.

2.4. All procurements shall be in accordance with the current annual budget.

2.5. All procurements shall be in accordance with the policies of Wataynikaneyap.

2.6. In the course of procuring goods and services for Wataynikaneyap, no person shall use their authority or office for personal gain.

2.7. When considering the advantages to Wataynikaneyap of maintaining a continuing relationship with a supplier, any arrangement which might in the long term prevent the effective operation of fair competition shall be avoided.

3. PROCUREMENT METHODS

3.1. Procurements shall be awarded to the supplier offering the Best Value.

3.2. Procurements shall only be awarded to businesses that are qualified to perform the services or supply the goods sought, in accordance with industry standards and qualifications regularly employed by transmission facility owners, including but not limited to health and safety qualifications and standards.

3.3. Subject to section 4.7 of this Procurement Policy, the manager of the procurement process shall give consideration to using a Competitive Procurement Process for any purchase in excess of $500,000.

3.4. Wataynikaneyap shall make commercially reasonable efforts to comply with applicable local procurement rules.

4. COMMITMENTS REGARDING FIRST NATIONS BUSINESSES

4.1. Wataynikaneyap may pre-qualify First Nation Businesses for particular contracts.

4.2. Wataynikaneyap shall:

a) work with the Participating First Nations to set the Indigenous Participation Target;

b) make commercially reasonable efforts to meet or exceed the Indigenous Participation Target;

c) annually review performance and update the Indigenous Participation Target; and

d) provide reports to Participating First Nations on Indigenous Participation KPIs, on a regular basis as set out in the Procedures Manual, and instruct its contractors and subcontractors to do the same.

4.3. Wataynikaneyap shall maintain and regularly update the Registry, and shall proactively communicate procurement opportunities to First Nations Businesses using the information contained in the Registry. In doing so, Wataynikaneyap shall clearly identify the work that is going to be contracted out and any requirements for the contract.

4.4. In order to facilitate First Nation Business development and foster a marketplace that includes competitive First Nation Businesses, Wataynikaneyap shall continue to support work on business readiness.

4.5. Where reasonable from a cost and timing perspective, Wataynikaneyap shall break work into smaller portions, so that a greater number of First Nations Businesses can access procurement opportunities.

4.6. Where reasonable from a cost and timing perspective, for contracts with reasonably anticipated and significant local impacts on a particular Participating First Nation, Wataynikaneyap shall provide a directed procurement opportunity to a qualified First Nations Business owned by that Participating First Nation. In so doing, Wataynikaneyap shall use open book negotiations or other appropriate mechanisms to demonstrate Best Value.

4.7. In Competitive Procurement Processes, Wataynikaneyap shall:

a) inform participants that Wataynikaneyap puts a priority on:

    i. local knowledge including demonstrated history of the ability to provide reliable service or supply of goods with an indigenous workforce, working with Participating First Nations, and ability to speak Ojibwaymowin and Anishiniinimowin;

    ii. full utilization of all available local content, including Participating First Nation labour, equipment, and materials;

    iii. sub-contracting opportunities for First Nations Businesses and Individual Member Businesses; and

iv. education, training, entrepreneurship and capacity-building opportunities for Individual Members;

and therefore requires each participant to prepare an Indigenous Participation Plan according to the instructions set out in Appendix A to this Procurement Policy;

b) inform participants that the quality of their Indigenous Participation Plan shall form 25% of their evaluation score, with 15% allocated to overall quality of the plan and 10% allocated to the percentage of contract price to be provided by First Nations Businesses and Individual Member Businesses;

c) inform participants that the contract shall contain obligations and defaults in relation to their performance on the Indigenous Participation Plan;

d) include in the documents: (i) a list of labour, material, equipment, services and other resources available from First Nations Businesses, (ii) a copy of the most recent version of Wataynikaneyap's *Indigenous Participation Guide* (this item to be provided for background purposes only), and (iii) a list of current gaps in community readiness and recommendations for addressing those gaps;

e) invite the Participating First Nations to participate in drafting the documents and evaluating the tenders/proposals;

f) during evaluation, provide a Price Preference to First Nation Businesses and Individual Member Businesses scaled to the size of the contract, as follows:

Contract value in CAN$	***Price preference as % of contact value***
From 0 to 50,000	15%
From 50,001 to 250,000	10%
From 250,001 to 1,000,000	8%
From 1,000,001 to 3,000,000	5%
From 3,000,001 to 5,000,000	4%
From 5,000,001 to 10,000,000	3%
From 10,000,001 to 15,000,000	2.5%
More than 15,000,000	No price preference

g) and, in order to ensure procurement opportunities are widely available:

   i. for spend of up to $250,000 assign Priority to Individual Member Businesses;

   ii. for spend of $250,001 to $1,000,000 assign Priority to First Nations Businesses owned by a single Participating First Nation; and

   iii. for spend of $1,000,000 or more, assign Priority to First Nations Businesses owned by two or more Participating First Nations, or in instances of competition between more than one such entity, assign Priority to the entity with the greater number of Participating First Nations owners.

4.8. Wataynikaneyap may designate certain long-term or high-value contracts for a Competitive Procurement Process open only to qualified First Nations Businesses.

4.9. If a First Nation Business or Individual Member Business participated in a Competitive Procurement Process but did not secure a contract, Wataynikaneyap may offer to meet with said business after the process in order to provide honest feedback, on condition that the meeting shall be held on a confidential and without prejudice basis, and on the express understanding that no commercially sensitive information shall be shared.

4.10. Wataynikaneyap shall perform an annual review of this Procurement Policy and the performance of Wataynikaneyap and all contractors and subcontractors on Indigenous Participation KPIs.

4.11. For major work that is being contracted or sub-contracted out, Wataynikaneyap shall ensure that the contractor and/or sub-contractor provides sustainable economic and business opportunities for First Nations Businesses and Individual Member Businesses. Wataynikaneyap will accomplish this by either:

a) requiring, or causing the contractor to require, that the terms of this Procurement Policy be followed for all procurements relating to the Project; or

b) agreeing to a different approach, but only if Wataynikaneyap is confident that the different approach will lead to better results.

5. PURCHASE AUTHORIZATION LIMITS

5.1. Purchase authorization limits are to be in accordance with the Material Contract as defined in the Shareholders Agreement.

6. HEALTH, SAFETY & ENVIRONMENTAL CONSIDERATIONS

6.1. Wataynikaneyap supports the use of environmentally sustainable and safe products and practices and expects staff to pursue this objective in the acquisition of goods and services.

This shall be accomplished by ensuring specifications to include environmentally sustainable choices and promote a safe and healthy workplace subject to both suitability and cost.

6.2. General principles in relation to environmental protection in the review of potential service providers and as part of any assessment of the performance of any supplier, contractor or subcontractor pursuant to any agreement with Wataynikaneyap include:

a) to comply with the Guiding Principles and other directives that have been received;

b) to preferentially select products that do not harm the environment in their manufacture, use or disposal;

c) to consider the environmental factors; and

d) to secure comprehensive, accurate and meaningful information about the environmental performance of products or services sufficient to determine environmental impacts.

APPENDIX A

Instructions for the Indigenous Participation Plan

1. The participant shall provide an Indigenous Participation Plan setting out how the participant shall:

    a) engage, communicate, collaborate and maintain good relationships with Participating First Nations;

    b) support and enhance commercial relationships with Participating First Nations and Individual Members;

    c) provide training, employment, entrepreneurship and capacity-building opportunities for Individual Members;

    d) address any identified community readiness gaps and recommendations; and

    e) track and report actual performance of the above, including through Key Performance Indicators ("KPIs").

2. Without limiting what may be included, each Indigenous Participation Plan shall:

    a) set out the participant's plan for communications with Participating First Nations;

    b) itemize anticipated subcontracts with First Nations Businesses and Individual Member Businesses;

    c) itemize plans for growing the scope of work subcontracted to First Nations Businesses over the course of the contract, including through transitioning subcontracts to First Nations Businesses as they become available to do the work;

    d) itemize intended purchases of supplies from Participating First Nations, First Nations Businesses or Individual Member Businesses, if available when required for the work and with the caveat that the participant may substitute such material with other material of the participant's choice subject to prior written notice and such substitute material meeting the requirements of the contract;

    e) itemize intended use of pieces of construction equipment leased or rented from Participating First Nations, First Nations Businesses or Individual Member Businesses, with the caveat that the participant may substitute such equipment with other equipment of the participant's choice subject to prior written notice;

    f) set out the number of Individual Members that shall be employed, in what position and for what period, and commit that if employment of any person identified is terminated prior to completion of the term indicated above, the participant shall hire another Individual Member in his/her place unless no such person is available and qualified;

    g) itemize any plans for education, training or entrepreneurship programs or other capacity-building initiatives for Individual Members, including duration, number of participants and projected outcomes;

    h) set out KPIs (see below) and tracking/reporting approaches; and

    i) include a summary table.

3. The KPIs included in the Indigenous Participation Plan shall include the following:

    a) number of Individual Members that are employees, and percentage of the workforce that this represents;

b) number of employees that speak Ojibwaymowin and Anishiniinimowin, and percentage of workforce that this represents;

c) number of Individual Members in management, supervisory or leadership roles;

d) dollar value of spend with First Nations Businesses and Individual Member Businesses, and percentage of total spend that this represents;

e) number of Individual Members participating in a participant-supported education, training or entrepreneurship program(s) or other capacity development initiatives; and

f) any other KPIs that the participant considers appropriate in relation to the participant's Project-related work and workforce

(collectively, the "Indigenous Participation KPIs").

4. Document X *[insert reference to document package]* includes a list of First Nations Businesses and Individual Member Businesses, and labour, material, equipment, services, and other resources available from Participating First Nations. Document X is provided for information only, and is intended to facilitate the participant's preparation of the Indigenous Participation Plan. It is the responsibility of the participant to review the qualifications, availability, and appropriateness of the listed resources and to make the necessary arrangement for their employment, purchase, rental, or use. To obtain contact details, participants may contact *[insert name]*.

5. Participants shall acknowledge that their Indigenous Participation Plan shall be attached to the contract and the contract shall contain obligations and defaults in relation to participant's performance of the Indigenous Participation Plan. A possible contract clause, which is provided for information only and may be changed at any time, is as follows: *"Contractor shall, at its own expense, comply with the plan for engagement with and participation of First Nations (the "Indigenous Participation Plan"), which is attached hereto as Schedule [X], and shall provide regular reporting on Contractor's implementation of the Indigenous Participation Plan as further described in [insert reference]. Should Contractor fail, in Owner's opinion, acting reasonably, to comply with the Indigenous Participation Plan, then Owner may direct Contractor to take remedial action in order to comply. Such remedial action may include but shall not be limited to directing Contractor to use Participating First Nations resources (either via Individual Member labour or by procuring goods or services from First Nations Businesses) nominated by Owner, unless Contractor can demonstrate to Owner's satisfaction that it would be commercially unreasonable to allow such participation. Notwithstanding the foregoing, price considerations shall not be the basis for concluding that it would be commercially unreasonable to allow such participation."*

APPENDIX ‘B’

WPPM Procurement Policy

Wataynikaneyap Power PM Inc.

Procurement Policy		
	Document:	PRO-001
	Owner:	CFO
	Revision:	0
	Issued:	2020.04.15
	Page:	Page 1 of 4

1. Purpose

a) The purpose of this Policy is to ensure that the purchase of materials, equipment and services (goods and services), by employees of the Wataynikaneyap Power PM Inc. ("WPPM") is performed in accordance with best business practices.
b) To obtain the best overall value (focusing on First Nation involvement, benefit of participating communities, quality, price, reliability, service, safety, environment, support and delivery) for Wataynikaneyap Power, the ratepayers and the limited partners.
c) To ensure accountability and transparency with a clear auditable trail for every acquisition.

2. Scope

a) WPPM must adhere to WPLP procurement policy dated June 12, 2018 or as otherwise updated by WPLP when fulfilling procurement activities.
b) Unless otherwise specified, any purchase of goods or services shall be made on a competitive basis, keeping with best practices, and in accordance with any applicable Federal, Provincial or Municipal legislation.
c) All departments therein of WPPM, shall have their purchasing requirements for goods and or services filled in accordance with this Policy.
d) No purchase of goods or services shall be authorized unless it is following this Policy.
e) No employee shall be exempt from this Policy.
f) All purchases under this Policy are to be entered and approved through the SAP Purchasing Module, or DocuSign and be in accordance with Section 3 of the Authorization Policy.
g) Appropriate segregation should exist between initiating a purchase, approving, receiving and then issuing payment for that same purchase.
h) Employees shall endeavour to contribute to environmental, economic and social sustainability as it pertains to the purchasing of goods and services.
i) Changes to this Policy require the approval of the CFO.
j) Supporting procedures and/or policies may be periodically updated provided there is no conflict with this Policy.

3. Exemptions to this Policy

a) The following list (but not limited to) are expenses that are not subject to this Policy:

- i. Procurement Card Purchases (A-103 Corporate Card policy)
- ii. Emergencies Purchases as defined in Section 5 Emergency Purchasing.
- iii. Utilities - Telephone & cell phone, Water/Gas/Electricity bills
- iv. Normal and recurring payroll related disbursements
- v. Recurring payments as described in Authorization Policy Section 5 “Statutory Payments”
- vi. Mobile equipment permits such as license plates, inspection renewals (does not include approval of any environmental permits)
- vii. Miscellaneous freight bills (as per contract)
- viii. Recurring monthly lease payments
- ix. Miscellaneous, recurring invoices providing they are on contracts (i.e. site security, contract labor, Mercer, WSIB - "Workers Safety Insurance Board" installments)
- x. Approved environmental & land permits
- xi. Logistics/Transportation distribution costs (Rail, Truck, warehousing, etc.)
- xii. Purchases of items set up in Company stores catalogs, (“Stores Inventory”, raw materials, and MRO supplies with a defined description, price, and physical inventory quantity previously approved by management as an inventory requirement and added to the Company catalog).

4. Requirement for Approved Funds

a) Any employee with the authorization to approve a purchase is accountable and responsible to ensure that either adequate budget exists or that any budget overage has been adequately justified, and that the purchase is not in violation of this Policy.

b) Where a requirement exists to initiate a purchase that is not part of the departments approved annual budget envelope, the responsible employee must get approval from the CFO and or the Board of Directors prior to any expenses being incurred.

c) All expenses must be approved by an authorized person in accordance with the FIN-001 Authorization Policy.

5. Emergency Purchasing

a) In the event of an emergency that requires the immediate purchase of any goods or services, reasonable effort shall be made to acquire the necessary authorization required under WPPM Authorization Policy Section 3 “Purchase Requisition or Signature Approval – Operating and Capital Expenditures” in advance of the purchase or as soon as possible after the emergency. An emergency is defined as a situation where there is an adverse effect on the health and safety of any person, the environment or a disruption of the services provided by the business units.

6. Business Ethics

a) All employees are subject to the policies and procedures of WPPM. The following policies in conjunction with PRO-001 shall provide the necessary guidance for ethical behavior during the purchasing process:
   i. B101 Code of Conduct;
   ii. B102 Reporting Allegations of Wrong Doing;
   iii. B103 Anti Corruption Policy; and
   iv. FIN-001 Authorization Policy

b) For clarity:
   i. All employees are expected to act in an ethical manner (B101);
   ii. No action or communication by any employee is to lead to one vendor or service provider having an advantage over another (B101);
   iii. No one purchase shall be divided to avoid compliance with this Policy and the Authorization Policy (FIN-001); and
   iv. The use of Company funds and resources to purchase personal goods or services is prohibited. Leveraging Company rates and discounts from vendors for personal gain is also prohibited, except in circumstances where a corporate agreement with a vendor explicitly considers extension of rates/discounts for personal use.

7. Pre-Payment or Progress payments

a) The following are expenses where milestone or pre-payments are allowed:
   i. Major equipment where there is more than one stage of production;
   ii. Services where mobilization is required; or
   iii. Non-tangible items such as software and licenses where the vendor requires prepayment in order to activate.

b) All milestone and pre-payment terms must be clearly defined in the Purchase Requisition and must be approved by the CFO.

8. Supporting Procedures

a) The following list of Procedures are supplemental to this Policy:

   i. PRO-001-01 Sourcing Procedure;
   ii. PRO-001-02 Purchasing Documents; and
   iii. A-103 Corporate Card.

[end of document]

Wataynikaneyap Power PM Inc.

Purchasing Procedures Sourcing Methods	Document:	PRO-001-01
	Owner:	CFO
	Revision:	0
	Issued:	2020.04.15
	Page:	Page 1 of 4

1. Purpose

To establish guidance for obtaining and summarizing competitive price quotations and providing a formal system of evaluating commitments of corporate funds prior to placement of purchase orders. The Company is committed to using supplier competition to effectively gain the most value for its business expenditures. Only Procurement personnel are to issue requests for bids for materials and services.

2. Scope

This procedure is applicable to all Employees at Wataynikaneyap Power PM Inc. (“WPPM) and is subject to the corporate purchasing policy PRO-001.

3. Prerequisites

3.1 Identification of required goods or services

Before any Purchasing is to take place the Employee is to have an understanding of what is required. The following (but not limited to) are considerations that must be taken into account prior to any of the other steps:

a) Are budget funds available?
b) Is there a Scope of Work or Material Specification?
c) What is the quantity required?
d) What is the delivery and requirement dates?
e) Is there a list of qualified Vendors or Service Providers?
f) Is this a standalone Purchase or part of a larger Project?

For all intents and purposes, once Section 3.1 has been satisfied a request is to be sent to Procurement for further processing and sourcing using the purchase requisition form.

3.2 Request for Information (RFI)

There may not be enough suitable information available to determine if a Vendor is qualified or has the resources to carry out the work required. An RFI may be issued to assist with determining if a Vendor is suitable to source from.

An RFI does not:

a) Reference a specific Scope of Work or Project.
b) Ask for prices or any type of rate.

c) Ask if a delivery date can be met.
d) Ask for signatures, bind or commit the Vendor.
e) Use the words “quote”, “proposal” or “tender”

An RFI may request (but is not limited to) the following information:

a) Work the Vendor is capable of doing.
b) Human resources (labour) available.
c) Equipment resources.
d) Training programs.
e) Health, safety or environmental practices.
f) If the Vendor is capable of working with different types of software.

The RFI process will prequalify Vendors for RFQ/RFP process and ensure they are compliant with our Health, Safety and Environmental obligations.

4. Sourcing

4.1 Once all of the prerequisite information is confirmed then Procurement may proceed with soliciting Vendors for information and prices. The following shall be used as the minimum standard when soliciting Bids:

a) All efforts shall be made to find more than one source of supply.
b) Three Bidders is the ideal number for a competitive bid.
c) Generally bidding is by invite only and not open to the Public.
d) All Bidders shall have access to the same information in the process.
e) All proprietary information and bids submitted are to be considered confidential.
f) All compliant Bids submitted are to be considered for award.
g) Any practice used to skew the outcome of the Bid or give one Bidder an advantage over another is considered unethical and prohibited.
h) Information about the award is not to be shared with the other Proponents.

If less than three bids are received, an explanation is to be provided and attached to the Purchase Requisition.

For the Purpose of this Document, the following are the accepted means of Sourcing:

4.2 Request for Quote (RFQ)

a) The Goods or Services are clearly defined and usually less technical, i.e., inventory items, cost center expenses and low level services.
b) The bidding documents are simple, often being an email with price and delivery being the evaluation criteria.
c) Review committee of one person from requesting department and a representative from purchasing.
d) Output documents are Purchase Orders with terms and conditions as required for Services.

4.3 Request for Proposal (RFP)

a) The Goods or Services are clearly defined by the Business Unit in a Scope of Work.
b) The Bidding documents are more complex with the Contract A and Contract B scenario.
c) Evaluation criteria for the Bid must be established.
d) Review committee is to be more than one person from requesting department, a representative from Purchasing, and one person finance department.
e) Output documents are a Purchase Order and a Contract (for Services).

Examples requiring an RFP: Large capital projects, intent to establish a multi-year contract or when there is a high-level scope with multiple deliverables.

4.4 Single or Sole Source Procurement.

Sole sourcing is where only one vendor is chosen to supply a quotation for goods or services. Sole sourcing should only be used where obtaining three quotations is not viable or reasonable. Therefore, sole sourcing shall be looked upon as a “method of exception” rather than the “normal method” of procurement. Sole sourcing approval must be done by the Wataynikaneyap Power COO or designate. The approval will be captured through the purchase requisition with approval documents for sole sourcing justification.

Purchases under $20,000

a) Sole Source Purchasing may be used for purchases where the anticipated price will be under $20,000. The quote from the sole source vendor may be written or verbal.
b) Output documents are a Purchase Order and a Contract (for Services).

Exceptions over $20,000

The following is the criteria to be used when justifying a single source for procurement purposes:

a) Only one source of supply has been identified for the requesting materials, equipment or services, and attempts to either identify additional sources or to modify the request to allow for alternate sources has not been successful.

b) The requested materials or equipment must be purchased from the original equipment manufacturer, in order to match or replace existing equipment.
c) The requested material, equipment, or services provide unique qualifications or technology.
d) The requested material and equipment has been approved as sole source by the Engineering Standards Group.
e) There is an urgent delivery requirement for the requested materials or service, and there is not sufficient time to solicit competitive bids.
f) Price quotations for the requested goods or services which definitely indicate a low cost provider are on file. Such quotations must be less than one year old, market rate information (i.e. labour rates, etc) and in the professional judgment of the Procurement Department, reflect the current market for the requested materials.
g) Output documents are a Purchase Order and a Contract (for Services).

5. Record of Change

A Record of Change shall be completed and maintained by the Procurement Manager. Changes made to this document are to be recorded and submitted to the CFO for review and approval prior to coming into effect.

Wataynikaneyap Power PM Inc.

Purchasing Documents	Document:	PRO-001-02
	Owner:	CFO
	Revision:	0
	Issued:	2020.04.15
	Page:	Page 1 of 5

1. Purpose

The purpose of this document is to provide information on the internal documents required for the purchasing of good and services. The foundation for these Documents is an approved Purchase Order from SAP which forms the basis for our internal audit trail as well as output documents for our Suppliers.

Purchasing Documents refers to any type of Purchase Order, Contract or Lease.

2. Scope

This procedure is applicable to all employees at the Wataynikaneyap Power and is subject to the corporate purchasing policy PRO-001

3. Prerequisites

3.1 Sourcing Requirements

Sourcing is to be completed as outlined in document PRO-001-01

3.2 Purchase Requisition

The Purchase Requisition (PR) precedes the issue of any Purchasing Document. Purchase requisitions are documents generated to notify the Company procurement group of material and/or service requirements. Requisitions provide a means of circulating a purchase request to designated approvers for their review and approval prior to initiating the purchase of material and/or services. The approval process for requisitions and purchase justification may be electronic through the SAP Procurement systems, DocuSign or by manual form, for internal departments using paper requisitions. See section 3 of PRO-001 Procurement Policy for expenditure exemptions not requiring a PR. The general steps and requirements for the processing of a Purchase Requisition include:

a) Submission of hand-written or electronic purchase requisition.; or
b) When automated systems (SAP Procurement systems or DocuSign) are available at a site, automated system requisitions are to be utilized for all purchases;

c) All purchases have clearly defined scope and item descriptions complete enough that the buyer and vendor can accurately identify the purchase requirement. (e.g., Part Number, Model, Size, Material, etc.);
d) Completed RFQ/RFP process or sole sourcing justification provided per PRO-001-01 Sourcing Methods;
e) Purchase requisition will need to be approved as per Section 3 “Purchase Requisition or Signature Approval – Operating and Capital Expenditures” per FIN-001 Authorization Policy;
f) Purchase requisitions approved manually or through DocuSign will be entered into the SAP and electronic copy attached to the SAP Requisition for audit purposes;
g) Historical approval documentation be maintained in hand-written or DocuSign as long as retrieval for subsequent audit purposes can be performed.

4. Purchasing Documents

4.1 Prerequisites

An approved PR is required in order to create a PO. A purchase order is the document that is used to order materials and services from a supplier and is the acceptance of a supplier's offer. Depending on the nature of the purchase, the contractual agreement can take the form of a purchase order or a contract as per Section 17 “Contracts” of the WPPM Authorization Policy. A PO must be issued prior to ordering required material and/or service.

4.2 Purchase Orders

The Purchase Order is an agreement between the Company and third party which includes at a minimum but is not limited to:

i. Agreed upon Price or estimated value: as per quote submitted
ii. Description of Goods, Services and Deliverables: as per quote submitted
iii. Purchase Order Number: A unique number assigned through SAP to a specific purchase order, to facilitate accountability throughout the ordering, receiving, and payment process.
iv. Date: All purchase orders must be dated to determine the contractual start date.
v. Supplier Name and Address: The Supplier's complete legal name and address must be displayed on the purchase order.

   vi. Ship to Address: The full address of the location where the material being purchased is to be delivered.
   vii. Payment Terms: The predetermined terms by which the Company will pay the supplier for the goods and/or services being purchased. In all cases, payment terms must be determined prior to an order being issued. Standard Company payment terms are outlined below in Section 9 “Payment Terms” of the PRO-001 Policy
   viii. Transportation Terms: Transportation terms identify two key pieces of information:
      a. F.O.B. (free-on-board) point: Specifies where title to the goods transfers from the seller to the buyer. "FOB Destination" should be designated if at all feasible.
      b. Freight Payment: Specifies which party is responsible for payment of freight charges to the carrier. "Freight Prepaid and Allowed" or "Freight Prepaid and Charge" are examples of typical freight payment terms.
   ix. Sales Tax Requirements: All goods and services purchased are either subject to or exempt from provincial and local sales, use, or value added tax. The tax status of each purchase is based upon information entered into in a properly completed requisition, purchase order or vendor record.
   x. Approval: at least one signature on purchase requisition through DocuSign as per Section 4 “Purchase Order – Operating and Capital Expenditures” as per WPPM Authorization Policy.

Types of Purchase Orders

a) Standard Purchase Orders
   i. Must be created from an approved purchase requisition in SAP;
   ii. No changes to internal standard Terms and Conditions;
   iii. Used for the purchase of goods based on quantity and price;
   iv. Are applicable to all non-exempt purchases;
   v. Are not required for Procurement Card purchases;
   vi. Are not to be created after the goods have been received; and
   vii. All inventoried material must be purchased in this manner.

b) Blanket Purchase Orders
   i. Must be created from an approved purchase requisition in SAP;
   ii. No changes to internal standard Terms and Conditions;

- iii. A monetary drawdown from an approved amount;
- iv. Defined validity period;
- v. Primarily used for the purchase of Services;
- vi. Must be used with Service Contracts for processing payments;
- vii. Used to issue work against a Master Services Agreement;
- viii. Shall not be used to purchase assets or capital equipment;
- ix. Acceptable for the purchase of Stationary supplies; and
- x. Changes to an existing the Blanket Order either to add additional funds or extend the validity period must be entered in a new Purchase Requisition.

c) Internal Purchase Order
- i. Must be created from an approved annual department budget;
- ii. A monetary drawdown from an approved amount;
- iii. Defined validity period;
- iv. Primarily used for the purchase of Services; and
- v. Must be attached to a specific vendor.

Invoices recorded against Blanket and Internal purchase orders require approval authorization in accordance with section 4 of FIN-001 Authorization policy prior to be processed for payment.

4.3 Reconciliation of PO to Invoice

In the instance of reconciling difference due to minor changes in invoices expenses and approved PO value, purchasing manager has authorization of 2% of PO value up to a maximum of $20,000 to adjust PO to actual invoice value. Changes greater than authorization limit will require a new PR with approvals as described in section 3 of FIN-001 Authorization Policy.

4.4 Contracts

The majority of "routine" materials and services are purchased using the Company's standard contract templates with terms and conditions and issued on Company’s standard purchase order. This section is to establish guidelines for the management of "non-routine" purchases such as project work where it is common to have vendor proposed changes to Company’s standard contract documents with detailed scope of work.

Given the increased risk of non-routine purchases, the review process and approvals must follow the requirements laid out in section 17 of the FIN-001 Authorization Policy. Internal legal or external counsel opinion will be obtained on the contract to ensure the company's risk is mitigated when standard terms and conditions are changed or when a vendor's contract template is used and spend is over $20,000.

5. Document Management

All copies of Purchasing Documents issued by WPPM are to reside on the Watay Partner and Finance drive in their respective folders. All Purchase order documents are to be retained for a period of 10 years.

The Contract file will have the following format:

E:\WatayPikang\Corporate\WataynikaneyapPower\Contracts – Vendor Name

The Purchase Order will have the following formats:

J:\Purchase Orders_PRs_VP1As\Purchase Orders & Cos-PO – Vendor Name

Quarterly reviews of "Partner" E drive access will be conducted by Procurement Department to verify user access and maintain document control. At this time Procurement will cross reference all new or changed contracts on file per the "Partner" E drive in the quarter with key stakeholders at Watay to ensure completeness of contracts.

6. Record of Change

A Record of Change shall be completed and maintained by the Procurement Manager. Changes made to this document are to be recorded and submitted to the CFO for review and approval prior to coming into effect.

HUMAN RESOURCES POLICIES AND PROCEDURES

FORTIS ONTARIO

Corporate Card	HR Policy:	A-103
	Page:	1 of 1
	Issued:	July 12, 2001
	Revised:	February 28, 2007
	Issue No.:	2.0

1.0 SCOPE

This policy applies to all employees of FortisOntario and its operating subsidiaries who are authorized to have a corporate credit card.

2.0 POLICY

Corporate charge cards are to be used for business purposes only. Employees are to use their cards whenever possible for business expenses including all meals, airfare, lodging, and car rentals. Senior management will determine the monthly limits based on specific job requirements.

FortisOntario will process the payment of all cards through one (1) monthly payment. Electronic monthly statements are distributed to all employees. Employees are responsible for reconciling & allocating these expenses to the appropriate accounts prior to the next billing cycle. All statements must be appropriately coded with **all** receipts attached prior to being signed by their Manager and returned to Finance.

Employees shall notify their Manager or department head immediately, in cases where the card becomes lost or stolen. Corporate credit cards shall be returned upon completion of an employee's active employment.

Wataynikaneyap Power PM Inc.

Authorization Policy

Document:	FIN-001
Owner:	CFO
Revision:	0
Issued:	2020.04.15
Page:	Page 1 of 9

1 - Objective

a) The objective of this Policy is to outline the authorization levels for goods and service purchases, employee expense purchases using a corporate credit, financial transactions (i.e. cheque signing, approval of wire transfers, account transfers, direct deposits, credit facilities and other derivative instruments), monthly statutory payments, timesheet and payroll approval, disposition of assets, emergency purchases, and contracts.

b) This Policy is applicable to Wataynikaneyap Power PM Inc. (WPPM).

2 - Approval Levels

a) The following table outlines the positions assigned to the various Approval Levels where referenced within this Policy:

Approval Levels	Position Assigned
Level 1	• See Appendix A
Level 2	• See Appendix A
Level 3	• Director
Level 4	• Vice President, CFO & COO
Level 5	• President & CEO
Level 6	• Board of Director

b) Level 3 & 4 employees will be responsible for assigning and approving the allocation of resources to Levels 1 and 2 as outlined in Appendix A of this Policy.

3 - SAP Purchase Requisition or Signature Approval – Operating and Capital Expenditures

The following table outlines Approval Levels for SAP or Manual Purchase Requisition (PR), or signature approvals:

Approval Levels	Up to $14,999	Up to $39,999	Up to $99,999	Up to $199,999	$200,000 to $499,999	Over $500,000
Level 1	✓					
Level 2		✓				
Level 3			✓			
Level 4				✓	✓✓✓	✓✓✓
Level 5						✓

a) Splitting PRs to circumvent the Approval Levels is not permitted. PR Approval Levels are based on total pre-tax dollar value of the PR.
b) All PRs over $200,000 and under $500,000 require approval by 1 Vice President, CFO and COO (3 level 4 approvals).
c) All PRs over $500,000 require approval by Vice President, CFO, COO and the President.
d) The intent of the policy is to have the COO or CFO included in all approvals.

4 - SAP Purchase Order – Operating and Capital Expenditures

Manager of Finance will review SAP Purchase Order (PO) entered from approved PR and ensure accuracy. The list below provides fields verified for Manager of Finance to release PO:

- Levels of approvals are appropriate
- Coding of PO is appropriate to specific department/Capital Project
- PO Value matches PR

The following table outlines Approval Levels for PO approval in DocuSign:

Approval Levels	**Dollar Limit Per Approval Level**				
	Up to $14,999	**Up to $39,999**	**Up to $99,999**	**Up to $199,999**	**$200,000 and Over**
Level 1	✓				
Level 2		✓			
Level 3			✓		
Level 4				✓	✓✓

a) Splitting POs to circumvent the Approval Levels is not permitted. PO Approval Levels are based on total pre-tax dollar value of PO.
b) Evidence of Level 5/Level 6 approval not required for POs as approval received as part of PRs outlined in Section 3 above unless a material contract per.
c) No PO can be issued for a material contract as defined in Section 17 “Contracts” without Wataynikaneyap Power GP (“WPGP”) Board of Director approval.
d) When a PO has been issued for a material contract, a change order and an amendment PO can be processed up to and including the amount in the budget approved by WPGP Board of Directors. All change orders require the COO approval and the amended PO requires one Level 4 approval.

5 - Statutory Payments

WPPM makes ongoing statutory payments. Refer to Section 3 for Approval Levels for processing of payments. Supporting documentation is retained for record keeping purposes. Staff responsible for the preparation and review of supporting documentation for statutory payments are as follows:

Statutory Payment Type	Prepared by	Reviewed & Approved by
Corporate Income Taxes	Financial Accountant	Manager of Finance
Workplace Safety & Insurance Board	Financial Accountant	
Other Payroll payments including RRSP, Union Dues, Social Club and etc.		
Harmonized Sales Tax	Financial Accountant	
Statutory Payroll payments including employee tax, CPP, EI and EHT	Prepared and Submitted to CRA by payroll processor (ADP)	
Property Taxes	Municipality	Approval Levels in accordance with Section 3
Financing Interest and Fees	Financial Accountant /Lenders	Manager of Finance

6 - Corporate Credit Card Purchases

a) In accordance with Human Resources Policy A-103 Corporate Card, corporate credit cards are to be used for business purpose only including purchases of meals, travel, car rentals and lodging. Other permitted miscellaneous credit card purchase limits are outlined in Section 7 below. Approval Levels of all corporate credit card purchases are outlined in Section 9 below.

7 - Corporate Credit Card Miscellaneous Purchases

a) The purchase of Inventory items using corporate credit cards is not permitted. See threshold limits below for single purchases of miscellaneous expenses permitted on the corporate credit card:

Type of Other Expenses	Threshold
Capital Expenditures	Up to $2,500
Operating Expenses	Up to $5,000

b) Single one-time purchase limits of $1,500 are typically in place for corporate credit card purchases, so temporary increases to approval limits may need to be obtained from Finance in advance of the purchase transaction being completed. Changes to temporary limits will require same approvals as provided in section 9.

8 - Expense Report

a) An Expense Account Report form is to be prepared monthly for each employee for business expenses, other than those expenses incurred through the use of the corporate credit card. All expense amounts must be properly approved by the person whom the employee directly reports to as outlined in Section 9 and on expense report form. If Expense Report exceeds $10,000 approval by CFO or COO is required. Employees are required to provide receipts as evidence of expenditure. For further details regarding preparation of expense reports, refer to HR Policy A-104 Expense Accounts.

9 - Approval Level for Corporate Credit Card & Employee Expense Claims

a) Expense reports are to be reviewed and approved by the individual that the submitter reports directly to, as outlined in the table below:

Claims For	**Approver**
Employee	Supervisor, Manager, Director, Vice President, COO or President
Supervisor	Manager, Director, Vice President, CFO or COO
Manager	Director, CFO or COO
Director	Vice President, CFO or COO
CFO	Vice President or President
COO	President
President	Chair of the Board of Directors

11 - Invoices/Cheque Requisition Requiring Signature of Approval

a) In certain circumstances, the PR process may not be appropriate for the purchase of goods or services. Examples may include electricity purchases, legal, audit, or actuarial invoices. Additional exception examples have been provided in the Purchasing Policy. For these cases, invoices are to be approved by the appropriate level of management in accordance with Section 3 above, prior to being processed for payment.

b) For invoices to be charged against blanket POs, approval by the appropriate level of management in accordance with Section 4 above must be obtained prior to being processed for payment.

c) For invoices received from affiliate organizations (FNLP, FON, Newfoundland Power, OSLP and Fortis) two approvals must be obtained from either Level 4 or Level 5 in accordance with section 2.

d) For invoices to be charged against Service PO’s, approval by the requisition originator or manager is first required to verify that services have been received/performed satisfactorily. Then approval by the appropriate level of management in accordance with Section 4 above must be obtained prior to being processed for payment.

12 - Banking Transactions

a) Payment is the final stage of the commitment process. All banking transactions must be approved by two individuals who have been granted authority in accordance with a banking resolution that has been previously approved by the Board of Directors. Signing authority levels are outlined below:

Signing Authority Maximum Approval Levels for Banking Transactions	
Cheque Signing	Any two in Level 4 or 5 in accordance with Section 2.
Wire Transfers / Payments	
Credit Facility	
Electronic Bill Payments	

b) Credit Facilities are approved by the Board of Directors.

13 - Timesheet Approval

a) Timesheets are to be approved in ADP by the appropriate management level considering the most current organization chart. Approval authority is outlined as follows:
  - i. Vice President, CFO & COO (VP) Direct Reports:
    - i. VPs to approve all direct report timesheets in ADP on a timely basis for payroll processing. If VP is absent, have a delegate approve in ADP for payroll processing, AND VP to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).
  - ii. Director/Manager/Supervisor Direct Reports:
    - i. Approve all direct report timesheets in ADP on a timely basis for payroll processing. If absent:
      1. Operational group Directors/Managers/Supervisors - a designated Director/Manager/Supervisor approve in ADP for payroll processing, AND the Director/Manager/Supervisor is required to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).

   2. Non-operational group Directors/Managers/Supervisors – VP or another designate of same authorization level will approve in ADP for payroll processing, AND Directors/Managers/Supervisors required to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).

b) Where approvals of timesheets have been completed outside of ADP as outlined above, it is the approver's responsibility to retain sufficient evidence of review and approval as it may be subjected to further review.

14 - Payroll Approval Level

a) After reviewing ADP payroll reports and disbursements including supporting documentation (i.e. payroll detail report, status change form, payroll employee changes report, payroll register), payroll related payments are approved by the Chief Financial Officer.

15 - Disposal of Assets

a) Disposal of assets require appropriate level of approval in accordance with the following net book values upon disposition:

Net Book Value	Approval Level
Up to $74,999	Level 3
$75,000 and Over	Level 4

16 - Emergency Purchases

a) As defined in the Purchasing Policy, if an emergency exists, a reasonable effort shall be made to acquire the necessary authorization required in advance of the purchase. Approval evidence may be obtained outside of SAP. The appropriate level of documentation and approval in accordance with Section 3 above must be obtained as soon as possible after the emergency.

17 - Contracts

17.1 - WPPM Contracts on behalf of Wataynikaneyap Power LP (WPLP)

a. The Procurement Manager must review, prior to signing, and execution:
   i. All contracts with obligations in the aggregate or related financial exposure that exceed the Level 1 threshold as defined in Section 3,
   ii. Contracts entered by WPPM on behalf of WPLP that obligate WPLP to significant non-financial or performance obligations, such as warranties or indemnifications,

iii. Any quotation or proposal from a third party for the purchase of goods or services, and/or

iv. All material contracts as defined in the Wataynikaneyap Power GP Inc. Unanimous Shareholder Agreement (WPGP USA) dated August 27, 2015 quoted below:

> “ *1. Involves expenditures or payments in excess of $3,000,000 in aggregate;*
>
> *2. Involves expenditure or payments in excess of $500,000 in aggregate and has a term in excess of one year;*
> *3. Is outside of the ordinary course of the Partnership Business;*
> *4. Is in relation to land in respect of which a First Nation has an interest;*
> *5. Is in relation to Project Financing;*
> *6. Her Majesty the Queen in Right of Canada or Ontario or an agent of the Crown is a party;*
> *7. A First Nation is a party;*
>
> *And, for the avoidance of doubt includes the Project Management Agreements, all EPC Contracts and all Affiliate Contracts.”*

Contracts that do not exceed the Level 1 threshold as defined in Section 3 or meet the definition of Material Contract above, should also be reviewed by the Procurement Manager if there are concerns about the content of the contract. Whether or not a contract involves an expenditure of financial commitment, a minimum signature of CFO and COO will be required. Higher levels of approval would be required in accordance with the thresholds outlined in Section 3 and unanimous Board of Directors approval is required for all Material Contracts as defined in WPGP USA.

b. Commitments binding WPLP financially or contractually may not be made without first obtaining the necessary approvals. Documents bearing signatures in accordance with Section 3 of this policy must be in hand prior to the commitment. The dollar limits specified for a particular expenditure are for the entire expenditure. Dividing expenditures into smaller amounts to circumvent the intent of this policy is not permitted.

17.2 – WPLP Contracts

a. The Procurement Manager must review, prior to signing, and execution:

   v. All contracts with obligations in the aggregate or related financial exposure that exceed the Level 1 threshold as defined in Section 3,

   vi. Contracts that obligate WPLP to significant non-financial or performance obligations, such as warranties or indemnifications, and/or

vii. Any quotation or proposal from a third party for the purchase of goods or services, and/or

viii. All material contracts as defined in the Wataynikaneyap Power GP Inc. Unanimous Shareholder Agreement (WPGP USA) dated August 27, 2015 quoted below:

“ *1. Involves expenditures or payments in excess of $3,000,000 in aggregate;*

8. Involves expenditure or payments in excess of $500,000 in aggregate and has a term in excess of one year;
9. Is outside of the ordinary course of the Partnership Business;
10. Is in relation to land in respect of which a First Nation has an interest;
11. Is in relation to Project Financing;
12. Her Majesty the Queen in Right of Canada or Ontario or an agent of the Crown is a party;
13. A First Nation is a party;

And, for the avoidance of doubt includes the Project Management Agreements, all EPC Contracts and all Affiliate Contracts.”

Contracts that do not exceed the Level 1 threshold as defined in Section 3 should also be reviewed by the Procurement Manager if there are concerns about the content of the contract. Whether or not a contract involves an expenditure of financial commitment, a minimum signature of two officers of Wataynikaneyap Power GP Inc. (WPGP). Contracts that meet the definition of a Material Contract above will require unanimous WPGP Board of Directors approval.

b. Commitments binding WPLP financially or contractually may not be made without first obtaining the necessary approvals. Documents bearing signatures of WPGP officers must be in hand prior to the commitment. The dollar limits specified for a particular expenditure are for the entire expenditure. Dividing expenditures into smaller amounts to circumvent the intent of this policy is not permitted.

18 - Leases

a) WPPM on WPLP’s behalf is required to review and report on an ongoing basis contracts that are lease related. Any lease contract that conveys the right to control the use of an identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration must be submitted to Finance for review and consideration under US GAAP reporting requirements. Key stakeholders are required to respond to a quarterly questionnaire to ensure lease population completeness and accuracy.

19– Temporary Delegation of Signing Authority

a) In accordance with the Procurement Procedure delegation of approval is permitted during temporary absences of a person having permanent signing authority. The delegate must be of equal or higher status than that of the regular signing authority. A delegate of their signatures and the period of time for which the delegation is valid, is required.

b) In cases where the delegate is not of equivalent or higher status, and is named in an acting capacity for the position held but the permanent signing authority, an approval by the CFO or COO is required. If the CFO or COO is unavailable the CFO of FortisOntario may approve an individual in the CFO's absence.

20– Prepayment/Progress Payment Authorization

a) The Company issues payments to suppliers upon completion of services or material delivery. Requests to pay in advance of delivery must be approved by the CFO.

b) Capital or Repair Projects requiring progress payments require approval from the CFO and COO.

21– Cash Advances

c) VISA cash advances to a maximum of $500 for the $5000 credit limit cardholders and $1000 for cardholders with credit limits greater than $5000 can be used for extreme cases where employees travel to remote First Nations communities, need to pay for services such as transportation, translation, meals, lodging etc and cash payment is the only possibility. The Employee must reconcile the cash advance on the visa statement with supporting documentation.

22 - Complementary Policies

a) The following policies and procedures have been referenced within, and should be considered in conjunction with this Policy:
   - ii. PUR-001 Purchasing Policy
   - iii. A-103 Corporate Card
   - iv. A-104 Expense Accounts

[end of document]

Wataynikaneyap Power PM Inc.

Authorization Policy
Level 1 & 2 Allocation Process

Document: FIN-001 Appendix A
Owner: VP of Finance
Revision: 1
Issued: 2022-01-01
Page: Page 1 of 2

1 – Introduction

This Appendix provides a listing of position assignments to the Level 1 & 2 Approval Levels as noted in FIN-001. The Appendix also provides guidance on the change management requirements for making any updates to this Appendix.

2 – Approval Level Assignments

Level 1

Position	Name
Senior HR Advisor	K. Wright
Manager Accounting	F. Nisioiu
Executive Assistant	

Level 2

Position	Name
Senior Engineer	K. Kilfoil
Sr. Manager Health Safety & Environment	N. Hammond
Manager Project Environmental Assessments	N. Sooley
Manager Project Control	J. Fretz-Joseph
Manager Communications	M. Kita
Manager Operations	Edwin Chopee
Manager Project Relations & Project Engineer	
Manager Construction	M. Applin
Manager IT	Geoff Visentin

3 - Change Management

a. Level 3 & 4 Employees are responsible for assigning and approving the allocation of resources to the Approval Levels outlined in Section 2 above, and to ensure the steps below are followed:
    i. New Employee onboarding paperwork is to be completed indicating what level, if any, is required; or
    ii. Changes to the existing authorizations in Section 2 are to be documented in an email and sent to Director of Finance.

b. The Director of Finance is to be informed of any changes required to this Document.

[end of document]

Wataynikaneyap Power PM Inc.

Stores and Inventory Management

Document: PRO-001-003
Owner: VP Finance
Revision: 0
Issued:
Page: Page 1 of 7

1. Purpose

To ensure the efficiency in the materials management process through assigning responsibilities and accountability within the Operations and Procurement departments and any Third Party providers. Furthermore, the identification of appropriate processes and procedures will be assigned to departments and Third Party Providers to execute the assigned responsibilities.

2. Scope

Maintenance/Operations and Stores/Procurement functions must work closely together in a seamless environment to optimize materials management processes. Neither process can fully accomplish its goals and objectives without the active involvement and support of the other functions.

3. Responsibility Assignment

The following table outlines the assigned responsibilities of the Operations and Procurement Departments:

Departments	**Responsibilities**
Operations:	i. Assist Stores in identifying obsolete materials, critical equipment, and critical spares ii. Adhere to Procurement Guidelines and Policies iii. Accurately estimate work order material requirements iv. Schedule planned worked orders with sufficient lead time to coordinate material availability and parts picking/staging v. Process all part returns with work order and cost code references in a timely manner vi. Ensure part issues are accurately charged to the correct work order/cost code number vii. Communicate with Procurement regarding material quality and delivery issues viii. Notify Procurement of parts that cannot be repaired so that work orders can be completed, and new items reordered
Procurement:	i. Create stores inventory purchase orders in a timely manner ii. Establish effective supplier agreements to ensure that materials cost, service leads, delivery and quality are maximized iii. Seek to optimize order cycle counts iv. Ensure products are delivered in a timely manner v. Conduct supplier performance reviews vi. Timely generation and review of stock purchase orders

	vii. Expedite orders as necessary viii. Ensure inventory database purchase lead times are accurate ix. Properly maintain master inventory table x. Accurately process all material transactions in a timely manner xi. Provide accurate database visibility for store’s materials xii. Work closely with the Operations department to identify “where used” information for spare pares inventories xiii. Provide a procedure for reserving stock parts xiv. Audit critical spares on a periodic basis xv. Identify excess inventories xvi. Provide easy access to critical spare part list for all important equipment xvii. Audit database quantities and field information on a systematic and prioritized basis

The following table outlines the assigned responsibilities of Third Party Providers outside of the organization who assist in the materials management process:

Third Party Provider	Responsibilities
Warehouse Provider	i. Maintain a professional and well-kept warehouse space ii. Provide proper and secure storage and identification of materials iii. Develop and implement material management “Best Practices” iv. Ensure the accuracy and completeness of inventory v. Ensure proper stock levels are maintained to optimize materials service levels with the materials investment levels vi. Provide high levels of customer service vii. Communicate with Procurement regarding supplier delivery issues

4. Inventory Procedures & Processes

4.1 Authority to Stock

Prior to adding a new item to inventory, the requestor is required to complete a “Materials Request Form.” The Materials Request Form outlines the following regarding the inventory: Asset Criticality, Delivery Time, Expected Usage, Reorder Point and Maximum Inventory level.

a) The requestor will complete the Materials Request form and include with the form a quote from the supplier supporting the new inventory and have the form signed off by their Manager.

b) All Material Request Forms are initially submitted to the Procurement Manager including a quote from the supplier supporting the new inventory being requested.

c) The Procurement manager will perform the initial review and approval of the Material Request Form, signing off indicating the information for the new inventory is valid

d) The Material Request Form will then be forwarded to the Director of Finance for final review and approval.

4.2 Store Order Review

To ensure all scheduled capital maintenance is completed during the fiscal year, it is essential that adequate inventory is on-hand at all times for routine and emergency maintenance. SAP contains a suggested re-order mechanism that monitors the consumption and replenishment of materials inventoried. When stock materials are created within SAP, a re-order point and re-order quantity are included. The following steps outline the process for ordering inventory to maintain adequate levels at site:

a) The re-order process starts with the Procurement Manager reviewing daily the Suggested Reorder Report within SAP.

b) Items are identified that require re-ordering and a final list is produced of items to be re-ordered with consideration given to the cost, frequency of consumption, etc.

c) With the final list approved, the Procurement Manager will sign-off on the final re-order list and send to the Director of Finance to sign-off.

d) When the Director of Finance has signed off on the final re-order list, the Procurement Manager will create the purchase orders required to fulfill the re-order materials required and circulate for appropriate approvals in accordance with the Authorization Policy.

4.3 Inventory Audits

The inventory balance on hand must be accurate to adequately support the yearly approved capital project, maintenance and emergency work as they arise to ensure the continued functionality of the transmission line. The accuracy of inventory in terms of actual stock and reported values is achieved through inventory audits.

The following table below outlines the various type of inventory audits that can be conducted, the frequency of the audit and the assertion being covered by performing the audit:

Count Type	Description	Frequency	Assertion
Physical Count	Counting all inventory at one time	Annual	Completeness
Cycle Count	Counting portions of the inventory at once so that over time all inventory is counted once a year	Quarterly	Existence
Spot Check	Choosing a few inventory items to be checked physically and compared to documentation (ideal for high turnover inventory)	Haphazard	Completeness

The following are to be excluded from any of the above-mentioned counting processes:

a) Items with a status of Inactive or Obsolete are only counted if there is inventory on-hand or if there was a transaction within the last twelve months

b) Order on Request Only ("ORO") items are only counted if there is inventory on-hand, or if there was a transaction within the last twelve months.

4.4 Adjustments

There exist instances where the physical inventory may differ from the book inventory. These differences may become apparent through inventory audits or when work order materials/staging is being completed. All differences that are identified need to be adjusted and reconciled so both the physical inventory and book inventory values are in agreeance. The following steps are taken to ensure both physical and inventory values are the same:

a) The Procurement Manager on a yearly basis will ensure the physical inventory balances as a result of an inventory audit or other means agrees to the book value of inventory (quantity and dollar value).

b) For any discrepancies identified, the Procurement Manager will prepare a stock discrepancy report in SAP which details the proposed adjustments and the reasoning for each variance.

c) The stock discrepancy report is sent to the Director of Finance for final review and approval. In some instances, additional review and signoffs are required for larger dollar adjustments to inventory

Common reasons for inventory adjustments include the following:

a) A cost adjustment is used to update the unit cost and the resulting total cost of the items on-hand.

b) A General Adjustment is used for any necessary adjustment that is not specifically done as part of an inventory reconciliation process. A general adjustment can make changes to the unit cost of the item and the physical quantity.

c) A Physical Adjustment is used to resolve any discrepancies found as the result of a Cycle Count, or any other informal check of a physical versus book inventory. The physical adjustment allows for an update of the on-hand inventory quantity.

d) Scrap adjustments are made when an item is deemed no longer of use, or is damaged beyond repair. This adjustment type plays a role in both the obsolescence and the rebuild processes. This adjustment type is used to change the status of items.

Every inventory adjustment should be viewed as an opportunity for improvement that can lead to greater corporate profitability. Meaning, if the inventory adjustment merely corrects the on-hand balance, continued discrepancies will likely result. The root cause of the discrepancy should be determined in an effort to prevent future occurrences of the error. (e.g. an improperly issued item, an item that was received but not binned properly, an item not checked out properly, etc.) Once of the same error. This will drive continuous improvement in inventory accuracy.

4.5 Receiving Items

Sufficient inventory documentation is required to ensure the assertions over inventory are supported, including the receiving documents. The following process outlines the controls regarding the receiving and recording of inventory.

a) All inventory received at a location (site or office) should include a packing slip or related document which will verify the items to be received in.

b) The receiving personal shall ensure the accuracy of the items being received. The receiving personal will verify the following information below:

    i. Vendor and recipient information
    ii. Shipping date
    iii. Purchase order number
    iv. Item description & stock number
    v. Quantity
    vi. Shortage, overage, and damage

c) Once all of the information has been verified on all three documents, the receiver shall check off each item and sign-off on the packing slip indicating the review has been completed. If any discrepancies are noted between the documents or damage to the products exist, Procurement shall be notified so next steps can be taken with the supplier to resolve the issue.

d) The packing slip is then sent to the Procurement Manager for final review and approval prior to receiving the items in SAP.

    i. If the items received are inventoried product, the inventory system is automatically updated when the items are received in SAP.
    ii. For non-inventoried items, the appropriate owner is notified and the product in stores until the items are need for the project.

Under no circumstances should an employee make a verbal agreement with a supplier to have materials purchased and delivered to the site without the proper documentation. If the situation is an emergency, and special arrangements have been made, the person requesting the materials should follow the policy regarding acquisition of an Emergency Purchase Orders and should notify stores of the delivery.

4.6 Inventory Returns

There may exist instances where materials requested for work orders and scheduled maintenance do not require all the material. This results in a return of inventory required to the storage site. The following steps outline the process for returning inventory back to site and within SAP:

a) For materials to be returned to inventory, the personnel completing the maintenance must complete a "Return to Stock" form. Information required in this form includes the following:
    i. Work order number for which the materials were requested for
    ii. Material description and quantity being return
    iii. Reasoning/explanation for the material return

b) The Return to Stock form is signed off by both the worker and job supervisor/manager and sent back with the materials to the storage site.

c) Site workers will review the Return to Stock form comparing the information being reported to the actual quantities returned and sign off on the form confirming there are no discrepancies. Any discrepancies in the amount reported and physical material should be brought to the attention of Procurement and the Job Supervisor/Manager so appropriate action can be taken to resolve the issue.

d) After the Return to Stock form is sent to the Procurement Manager for final review and sign off to process the credit to inventory in SAP.

4.7 Issuing Materials/Inventory

All materials issued out are required to have sufficient supporting documentation to support the request made. The following steps outline the process required to issue out inventory from the site as requests are received:

a) All requests for materials/inventory are made to the site through issuance of a work order or other document which details the materials and quantities required. All work orders must have a sign-off the job supervisor/manager prior to be fulfilled by the site location.

b) The site workers will fulfill the order in accordance with the materials listed on the work order or other document provided and signoff once the order is filled.

c) The personnel completing the job will review the materials and compared the quantities to the work order to ensure the accuracy in the materials provided. Upon completion of the review, the worker shall sign off on the work order confirming all the materials requested have been provided for the job to be performed.

Exhibit F, Tab 4, Schedule 1

Depreciation, Amortization and Depletion

DEPRECIATION, AMORTIZATION AND DEPLETION

WPLP will use straight-line depreciation calculations based on the depreciable gross book value of each asset class. The useful lives and corresponding depreciation rates determined by WPLP are shown in Table 1.

Table 1 – Useful Lives and Depreciation Rates

OEB Account and Description	Useful Life (Yrs)	Depreciation Rate
1715 - Station Equipment (Station and Transformers)	50	2.00%
1715A - Station Equipment (Switches and Breakers)	40	2.50%
1715B - Station Equipment (Protection and Control)	20	5.00%
1720 - Towers and Fixtures	60	1.67%
1725 - Poles and Fixtures	45	2.22%
1730 - Overhead Conductor and Devices	45	2.22%
1908 – Buildings and Fixtures	50	2.00%
1915 – Office Furniture	10	10.00%
1920 – Computer Hardware	5	20.00%
1930 - Transportation Equipment[1]	5-10	10.00-20.00%
1611 – Computer Software	5	20.00%

WPLP's 2024 depreciation expense is summarized in Table 2, with detailed calculations provided in **Appendix 'A'** of this Schedule. WPLP's proposed depreciation expense for the 2024 test year is based on a forecast of net fixed assets, calculated using the 12-month average of forecast monthly in-service additions in respect of all in-service portions of the transmission system, including those that are expected to go into service during the 2024 test year.[2] This approach is consistent with WPLP's approach to calculate rate base, as detailed in Exhibit C-3-1.

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[1] All in-service fleet is based on 5-year useful life (20% depreciation rate).

[2] WPLP plans to use a 12-month average of forecast monthly in-service additions until all assets are in service.

Table 2 – 2024 Depreciation Expense (Costs in $000’s)

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**
1715 - Station Equipment (Station and Transformers)	900	5,129	6,029
1715A - Station Equipment (Switches and Breakers)	157	510	667
1715B - Station Equipment (Protection and Control)	75	533	607
1720 - Towers and Fixtures	1,909	6,571	8,481
1725 - Poles and Fixtures	0	767	767
1730 - OH Conductor and Devices	3,385	9,760	13,145
Sub-Total Transmission System Plant	**6,427**	**23,270**	**29,697**
1908 - Buildings and Fixtures	4	13	17
1915 - Office Furniture and Equipment	2	8	10
1930 - Transportation Equipment	21	79	100
1611 - Computer Software	129	481	610
Total	**6,582**	**23,851**	**30,433**

The useful lives determined by WPLP are comparable to the range of useful lives used by other Ontario transmitters, as well as the ranges in the Asset Depreciation Study prepared by Kinectrics Inc.[3], as shown in Table 3 below. For this comparison, WPLP used the useful life ranges as stated by CNPI, FNEI and GLPT (prior to being acquired by Hydro One). With the exception of towers and fixtures,[4] WPLP adopted the same useful lives as CNPI Transmission.

WPLP adopted a 60-year useful life for towers and fixtures, since the lattice steel towers employed are expected to last longer than wood-pole structures. This approach is consistent with GLPT’s differentiation between 45-year useful lives for wood poles/towers, vs. 60-year useful lives for steel and composite poles/towers.

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[3] EB-2010-0178, Asset Depreciation Study for the Ontario Energy Board, July 8, 2010.

[4] CNPI’s transmission towers and fixtures associated with Account 1720 consist primarily of wood poles, and are therefore not comparable to WPLP’s towers and fixtures.

The only fixed asset account where WPLP's useful life is outside the Kinectrics recommended range is Account 1730 (Overhead Conductors and Devices). WPLP notes that the assessment of overhead conductor included in the Kinectrics Depreciation Study focused solely on the aluminum and copper conductors used for phase and neutral conductors in overhead lines. In contrast, the OEB's definition of Account 1730[5] includes assets such as ground wires (which for WPLP include integrated fiber optic cable), ground clamps, insulators, lightning arresters and switches. WPLP therefore considered it appropriate to use an overall expected life of 45 years for this asset category, consistent with the useful life adopted by each of CNPI and FNEI.

HONI, B2M and NRLP are excluded from the analysis in Table 3 since these transmitters all rely on a more complex method of calculating depreciation expense.[6]

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[5] OEB Accounting Procedures Handbook; Issued December 2011; p.56

[6] These transmitters rely on a Depreciation Rate Review study completed by a third-party expert on behalf of HONI, which calculates depreciation rates in consideration of differences in estimated remaining life by asset vintage.

Table 3 – Comparison of Useful Lives

WPLP			**CNPI Useful Life Range**[7]	**FNEI Useful Life Range**[8]	**GLPT Useful Life Range**[9]	**Kinectrics**	
OEB Account and Description	**Useful Life (Yrs)**	**Depreciation Rate**				**Category/Component**	**Useful Life Range**
1715 - Station Equipment (Station and Transformers)	50	2.00%	50	10-50	45-50	Power Transformers (Overall)	30-60
						Rigid Busbars	30-60
						Steel Structure	35-90
1715A - Station Equipment (Switches and Breakers)	40	2.50%	40		30-45	Station Independent Breakers	35-65
						Station Switch	30-60
1715B - Station Equipment (Protection and Control)	20	5.00%	20		5-20	DC System (Overall)	15-20
						Digital & Numeric Relays	15-20
1720 - Towers and Fixtures	60	1.67%	45	N/A	60	N/A[10]	
1725 - Poles and Fixtures	45	2.22%	45	15-40	45	Fully Dressed Wood Pole (Overall)	35-75
1730 - Overhead Conductor and Devices	45	2.22%	45	25-60	60	Overhead Conductors	50-75
1908 - Buildings and Fixtures	40	2.50%	N/A	20-40	25	Administrative Buildings	50-75
1915 - Office Furniture and Equipment	10	10.00%	N/A	4-10	10	Office Equipment	5-15
1930 - Transportation Equipment	5-10	10.00-20.00%	N/A	5-7	5	Vehicles (Various)	5-20
1611 – Computer Software	5	20.00%	N/A	4	5-15	Computer Software	2-5

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[7] EB-2014-0204, Exhibit 4, Tab 10, Schedule 2, p.1.

[8] EB-2016-0231, IRR 6-Staff-30(e).

[9] EB-2014-0238, Exhibit 4, Tab 3, Schedule 1, p.2.

[10] The Kinectrics Depreciation Study did not include lattice steel structures.

‘APPENDIX A’

Depreciation Expense Detail

Calculation of Depreciation Expense - All Assets

Accounting Standard ASPE
Year 2024

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Intangible	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	300,000	-	300,000	3,000,000	3,050,000	5	20.00%	610,000
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	216,854,379	-	216,854,379	145,838,566	301,447,883	50	2.00%	6,028,958
47	1715A	Station Equipment (Switches and Breakers)	21,071,060	-	21,071,060	10,189,112	26,689,589	40	2.50%	667,240
47	1715B	Station Equipment (Protection and Control)	9,021,703	-	9,021,703	5,853,461	12,149,550	20	5.00%	607,477
47	1720	Towers and Fixtures	381,456,968	-	381,456,968	231,572,120	508,840,677	60	1.67%	8,480,678
47	1725	Poles and Fixtures	33,493,965	-	33,493,965	2,024,377	34,520,424	45	2.22%	767,121
47	1730	OH Cond and Devices	451,670,202	-	451,670,202	237,516,888	591,541,755	45	2.22%	13,145,372
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		General Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	5,000,000	833,333	50	2.00%	16,667
8	1915	Office Furn & Equipment	40,000	-	40,000	80,000	96,667	10	10.00%	9,667
	1920	Comp Hardware	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	155,392	-	155,392	670,000	499,558	5	20.00%	99,912
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**1,114,063,668**	**-**	**1,114,063,668**	**641,744,523**	**1,479,669,437**			**30,433,091**

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard	ASPE
Year	2024

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	36,199,418	-	36,199,418	9,702,189	45,001,642	50	2.00%	900,033
47	1715A	Station Equipment (Switches and Breakers)	6,193,134	-	6,193,134	-	6,277,690	40	2.50%	156,942
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	1,491,470	-	1,498,363	20	5.00%	74,918
47	1720	Towers and Fixtures	112,607,525	-	112,607,525	1,635,674	114,567,969	60	1.67%	1,909,466
47	1725	Poles and Fixtures	-	-	-	-	-	-	-	-
47	1730	OH Cond and Devices	134,211,114	-	134,211,114	20,274,716	152,335,195	45	2.22%	3,385,227
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**290,702,661**	**-**	**290,702,661**	**31,612,579**	**319,680,858**			**6,426,586**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard	ASPE
Year	2024

CCA Class	**OEB**	**Description**	**Opening Gross PP&E**	**Less Fully Depreciated**	**Net for Depreciation**	**Current Year Additions**	**Total for Depreciation**	**Useful Life**	**Depreciation Rate**	**Depreciation Expense**
Transmission Plant			A	B	C = A - B	D	E = Avg Monthly Opening	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	180,654,961	-	180,654,961	136,136,377	256,446,241	50	2.00%	5,128,925
47	1715A	Station Equipment (Switches and Breakers)	14,877,926	-	14,877,926	10,189,112	20,411,899	40	2.50%	510,297
47	1715B	Station Equipment (Protection and Control)	7,530,233	-	7,530,233	5,853,461	10,651,187	20	5.00%	532,559
47	1720	Towers and Fixtures	268,849,443	-	268,849,443	229,936,446	394,272,709	60	1.67%	6,571,212
47	1725	Poles and Fixtures	33,493,965	-	33,493,965	2,024,377	34,520,424	45	2.22%	767,121
47	1730	OH Cond and Devices	317,459,087	-	317,459,087	217,242,172	439,206,561	45	2.22%	9,760,146
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**822,865,615**	**-**	**822,865,615**	**601,381,944**	**1,155,509,021**			**23,270,260**

Exhibit F, Tab 5, Schedule 1

Income and Property Taxes

INCOME AND PROPERTY TAXES

A. Overview

This Schedule provides the details supporting WPLP's forecasted income tax expense for the purpose of rate recovery for the 2024 test year. It also provides context with respect to the tax implications of WPLP's corporate structure with respect to various legislation.

Appendix "A' to this Schedule contains detailed calculations of WPLP's income tax expenses for the 2024 test year, which have also been filed in Excel format. A copy of WPLP's most recent tax return is included as an Appendix "A" to Exhibit A-7-1.

WPLP has calculated a total income tax expense of $501,972 for the 2024 test year. As detailed in this Schedule, this expense is limited to the Ontario Corporate Minimum Tax ("OCMT"), as applicable to its partners, because WPLP is a limited partnership and continues to have loss carry forwards in excess of taxable income for 2024.

B. Corporate Structure

WPLP is not a corporation that is exempt from tax under Section 149(1) of the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario). As such, WPLP is not subject to the payments in lieu of corporate income taxes ("PILs") regime under the *Electricity Act, 1998*.

WPLP is a limited partnership pursuant to the *Limited Partnerships Act* (Ontario). As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes, but is required to compute its taxable income, which is then allocated to its partners as follows:

- 51% of WPLP's taxable income is allocated to First Nation LP, whose limited partnership interests are held directly by the 24 Participating First Nations in equal shares; and,
- 49% of WPLP's taxable income is allocated to Fortis (WP) LP, whose limited partnership interests are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%).

The 24 Participating First Nations that are shareholders of First Nation LP are not subject to corporate income tax. As such, the 51% portion of WPLP's taxable income that is allocated to First Nation LP is not subject to income tax, which results in savings to ratepayers.

C. Regulatory Income Tax Expense

A combined income tax rate of 26.5% (15% federal + 11.5% provincial) is used for the calculation of the 2024 income tax expense. However, as detailed in Appendix "A", WPLP's forecasted allowable CCA deduction of approximately $58.03 million and use of loss carry forwards, result in zero taxable income.

D. Ontario Corporate Minimum Tax

The Ontario Corporate Minimum Tax ("OCMT") rate is 2.7%. This rate is applied to accounting income, without most tax adjustments, and the tax payable is equal to the amount by which the OCMT exceeds the Ontario corporate income tax.

Detailed calculations are provided in Appendix "A" with WPLP's 2024 forecasted OCMT payable summarized in Table 1 below.

Table 1 – WPLP's 2024 Ontario Corporate Minimum Tax ($000's)

Item	Description	Allocation / Rate	Amount
A	WPLP Regulatory Net Income (before Tax and adjustments)		37,942
B	% of LP Interests Held by Taxable Entities	49%	
C = A x B	Regulatory Net Income subject to Taxation		18,592
D	Ontario Minimum Corporate Tax Rate	2.7%	
E = C x D	***Ontario Minimum Corporate Tax***		***502***
F	Ontario Corporate Income Tax Payable		0
G = E-F	**Ontario Corporate Minimum Tax Payable**		**502**

As detailed in Appendix “A”, WPLP will record credits in the amount of the OCMT paid to be applied to reduce taxes payable in future years.

E. Reconciliation Between Regulatory Net Income Before Tax and Taxable Income

The difference between WPLP’s regulated net income before tax and WPLP’s taxable income consists of tax adjustments related to depreciation, CCA and financing fees (which are deductible for tax purposes over a five-year period), as detailed in Appendix “A”. WPLP confirms that the depreciation amount included in Appendix “A” is equal to the depreciation expense included in its 2024 test year revenue requirement, as calculated in Exhibit F-4-1.

WPLP’s CCA calculation for the 2024 test year is provided in Appendix “B” to this Schedule, and includes the effect of Accelerated CCA.

F. Taxable Income and Income Tax Expense

WPLP’s confirms that its forecasted 2024 regulatory net income before tax is equal to the return on equity component of its revenue requirement, as calculated in Exhibit G-2-1. WPLP’s taxable income is determined by adding depreciation expense and deducting CCA and financing fees, following which, the resulting taxable income is allocated to each partner, as detailed in Appendix “A”. For each partner (i.e. First Nation LP and Fortis (WP) LP), Appendix “A” then calculates the relevant income tax expense, with consideration of applicable tax rates and loss treatment of losses/credits.

The OCMT portion of each partner’s tax expense calculation is applied to an allocation of WPLP’s regulatory net income before tax, which is shown as “Allocation of Accounting Income” in Appendix “A”.

As discussed above, First Nation LP and its direct shareholders are not taxable entities. The tax rates applicable to First Nation LP are therefore set at 0% and the resulting income tax and OCMT expenses are $Nil.

The Fortis (WP) LP section of Appendix "A" provides the income tax and OCMT calculations applicable to Fortis (WP) LP's 49% allocation of WPLP's income, according to the process described above.

G. Property Tax Expense

WPLP's has included an immaterial property tax expense (less than $1,000) in its 2024 test year OM&A cost forecasts in relation to WPLP's land interests for the Wataynikaneyap TS.

APPENDIX "A"

WPLP 2024 Income Tax Calculation

WPLP
Calculation of Utility Income Taxes
2024 Test Year
($000's)

SUMMARY OF TAX EXPENSE

	2024
First Nation LP	0
Fortis (WP) LP	502
Total	**502**

WPLP

Line No.	Particulars		2024	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)		37,942	(1)
2	Book to Tax Adjustments:			
3	Depreciation and amortization		30,433	
4	Capital Cost Allowance		-58,030	
5	Other		0	
6	Total Adjustments	$	-27,597	
7	Regulatory Taxable Income/(Loss) before Loss Carry Forward	$	10,345	
	Allocation of Taxable Income			
8	First Nation LP (51%)		5,276	
9	Fortis (WP) LP (49%)		5,069	
10	Total	$	10,345	
	Tax Rates			
11	Federal Tax		15.00	%
12	Provincial Tax		11.50	%
13	Total Tax Rate		26.5	%

WPLP
Calculation of Utility Income Taxes
2024 Test Year
($000's)

First Nation LP

Line No.	Particulars		2024
	Determination of Taxable Income		
1	Allocation of Taxable Income from WPLP		5,276
4	Tax Rate		0.00 %
5	**Income Tax Expense**	**$**	**0**
	Determination of Corporate Minimum Tax		
	Allocation of Accounting Income from WPLP		19,350
	Corporate Minimum Tax Rate		0.00 %
	Corporate Minimum Tax Payable (Utilized)	**$**	**0**
	Total Taxes Expense for First Nation LP	**$**	**0**

WPLP
Calculation of Utility Income Taxes
2024 Test Year
($000's)

Fortis (WP) LP

Line No.	Particulars		2024	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		5,069	
2	Loss Carryforward		-5,069	
3	Taxable Income after Loss Carryforward		0	
4	Tax Rate		26.50	%
5	**Income Tax Expense**	**$**	**0**	
	Loss Continuity Schedule			
6	Opening Losses Carryforward		-36,849	
7	Losses (Incurred)/Utilized during the year		5,069	
8	Closing Losses Carryforward		-31,780	
	Determination of Corporate Minimum Tax			
9	Allocation of Accounting Income from WPLP		18,592	
10	Corporate Minimum Tax Rate		2.70	%
11	Corporate Minimum Tax Potentially Applicable		502	
12	Ontario Income Tax		0	
13	**Corporate Minimum Tax Payable (Utilized)**	**$**	**502**	
14	Opening CMT Credit Carryforward		567	
15	CMT Credit Incurred/(Utilized)		502	
16	Closing CMT Credit Carryforward		1,069	
17	**Total Taxes Expense for Fortis (WP) LP**	**$**	**502**	

(1) The regulated income of $37,440,000 provided in G-2-1 Table 1 has been grossed up for tax purposes.

APPENDIX “B”

WPLP 2024 CCA Calculation

WPLP
Calculation of Utility Income Taxes
2024 Test Year
($000's)

CCA Class	Opening UCC	Net Additions	Contribution in Aid of Construction	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Accelerated CCA Initiative	Closing UCC
1	-	5,000	-	5,000	(2,500)	2,500	0.04	100	200	4,700
8	28	80	-	108	(40)	68	0.20	14	19	76
10.1	47	670	-	717	(335)	382	0.30	115	208	394
12	-	3,000	-	3,000	(1,500)	1,500	1.00	1,500	-	1,500
47	974,495	632,995	(750,808)	856,681	(316,497)	540,184	0.08	43,215	12,660	1,551,615
UCC	974,570	641,745	(750,808)	865,506	(320,872)	544,634		44,943	13,087	1,558,285
							TOTAL CCA	**58,030**		

Exhibit G, Tab 1, Schedule 1

Capital Structure

CAPITAL STRUCTURE

In contrast to the 2022 and 2023 rate years, during which WPLP used a deemed capital structure for rate-making purposes comprised of 60% debt (4% short-term and 56% long-term) and 40% common equity, in the current Application, WPLP proposes to use its actual capital structure for rate-making purposes for the 2024 rate year. As described below, WPLP's use of its actual capital structure for the 2024 rate year is consistent with the terms of the Federal Funding Framework and results in savings for ratepayers. WPLP plans to revert back to using the deemed capital structure for rate-making purposes upon receiving the contribution in aid of construction (CIAC) pursuant to the Federal Funding Framework following completion of the Project.

WPLP therefore proposes to use its actual capital structure of 72.8% debt (0% short-term[1] and 72.8% long-term) and 27.2% common equity for rate-making purposes for the 2024 rate year. Table 1 illustrates the application of this capital structure to WPLP's 2024 rate base.

Table 1 – Capital Structure

	Capitalization Ratio	
	(%)	**($)**
Long-term Debt	72.8%	$1,072,606,245
Short-term Debt	0.0%	$0
Total Debt	*72.8%*	*$1,072,606,245*
Common Equity[2]	*27.2%*	*$400,000,000*
Total	**100%**	**$1,472,606,245**

WPLP, Canada and Ontario signed definitive documents to establish the Federal Funding Framework on July 3, 2019. Under the Federal Funding Framework, subject to appropriation by Parliament, Canada is expected to provide $1.55 billion in funding in relation to the project upon

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[1] As WPLP is using actual capital structure and all debt is from third parties, all debt has been allocated to long-term debt. For further details see Exhibit G-2-1.

[2] Based on Federal Funding Framework, WPLP is capped at $400 million equity due to the sliding scale and forecasted total project costs.

completion of construction, which will serve to reduce the resulting ratepayer impact in two ways. First, a portion of the funding will be applied as a CIAC, thereby reducing WPLP’s rate base in respect of the Remote Connection Lines. Second, the remainder of the funding will be provided to an independent Trust, which will use the funding to help offset the impacts of the Remote Connection Lines on RRRP for Ontario ratepayers.

The portion of the federal funding that will be provided to WPLP as a CIAC will be determined based on WPLP's total capital costs for the project as determined in this application.[3] More particularly, to provide an incentive to control and reduce capital costs during construction, the Federal Funding Framework establishes a sliding scale such that, as WPLP’s capital costs increase, the amount of the CIAC increases at a rate that has the effect of reducing WPLP’s deemed equity position in the project. The application of the federally funded CIAC to the Remote Connection Lines results in a reduction to the fixed monthly charges that WPLP recovers from HORCI, which will in turn result in HORCI needing to collect less revenue from the RRRP pool. The provision of the remaining federal funding to the independent Trust will further reduce rate impacts for Ontario ratepayers because the independent Trust will be required to provide funds to the IESO to be applied against the total RRRP funding that the IESO needs to collect from Ontario ratepayers each month, until such time as the independent Trust's funds are exhausted.

In applying the sliding scale under the Federal Funding Framework, if and when the total capital costs for the project are higher than $1.87B, WPLP’s partners are prohibited from making equity contributions greater than $400M.

WPLP’s partners (First Nation LP and Fortis (WP) LP) made significant equity contributions in 2022 and 2023 in consideration of assets coming into service and the overall financing and funding framework for the project:

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[3] See Exhibit B-1-5 for additional information.

- In 2022, First Nation LP and Fortis (WP) LP contributed $245,760,000 ($120,998,107 and $124,761,893, respectively); and

- In 2023, First Nation LP and Fortis (WP) LP will contribute an additional $60,300,000 ($30,753,000 and $ 29,547,000, respectively).

As WPLP forecasts that the total capital cost of the project will increase beyond $1.87B in 2024, its partners will not be permitted to make additional equity contributions upon additional assets coming into service during the year other than retaining earnings. Consequently, a greater portion of WPLP's capital will be funded by debt until such time that it receives the CIAC from Canada under the Federal Funding Framework, which is expected at the end of 2024. Upon receiving the CIAC from Canada, WPLP will revert back to using the deemed capital structure consistent with its approach in 2022 and 2023.

Use of its actual capital structure for rate-making purposes for 2024 provides savings for ratepayers of $6 million as compared to use of the deemed capital structure. These savings arise from applying the cost of debt, which is lower than the cost of equity, to 72.8% of the capital structure rather than to the 60% that would attract the cost of debt using the deemed capital structure.

The cost of capital parameters are discussed in Exhibit G-2-1.

Exhibit G, Tab 2, Schedule 1

Cost of Capital

COST OF CAPITAL

A. Overview

This schedule supports the cost rate applied to each component of WPLP's 2024 cost of capital. WPLP's total cost of capital for the 2024 test year is summarized in Table 1 below.

Table 1 – Capital Structure and Cost of Capital

	Capitalization Ratio		**Cost Rate**	**Return**
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	72.8%	$1,072,606,245	5.85%	$62,771,706
Short-term Debt	0.0%	$0	4.79%	$0
Total Debt	*72.8%*	*$1,072,606,245*	*5.85%*	*$62,771,706*
Common Equity	*27.2%*	*$400,000,000*	*9.36%*	*$37,440,000*
Total	**100%**	**$1,472,606,245**	**6.81%**	**$100,211,706**

B. Cost of Equity

WPLP's proposed revenue requirement reflects its use of the OEB's rate of return on equity ("ROE") of 9.36% for 2023 rate applications, as established by the OEB's Cost of Capital Parameter update letter of October 20, 2022, as a placeholder. WPLP will update this rate at a later stage of the proceeding to reflect the OEB's ROE for 2024 applications once the OEB publishes its cost of capital parameters for 2024.

C. Cost of Short-Term Debt

Given WPLP is using its actual capital structure and all debt financing of construction costs is through third parties, all debt has been allocated to long-term debt. WPLP is therefore showing no return for short-term debt.

D. Cost of Long-Term Debt

As this is WPLP's third transmission revenue requirement application and it continues to be focused on constructing the Transmission System while transitioning into its role as an operating transmitter, this section first describes the process and overall approach to financing that WPLP has taken and then explains the basis for the proposed cost of long-term debt.

1. Context and Process Related to Project Financing

WPLP has worked with Price Waterhouse Coopers ("PwC") to secure appropriate third-party financing for the construction of its transmission system. WPLP entered into a 'club deal' with a consortium of five bank lenders (the "Senior Bank Lenders") and Ontario to allow for better financing terms through increased competition among the lenders which supported a better outcome for WPLP and, ultimately, for ratepayers. In 2019, WPLP negotiated a Common Terms and Inter-Creditor Agreement ("CTIA") with Ontario and the Senior Bank Lenders (collectively the "Lenders") to provide total project financing of up to \$2.02 billion, consisting of up to \$1.34 billion from Ontario (the "Ontario Facility") and up to \$680 million from the Senior Bank Lenders (the "Senior Bank Facility"). For clarity, WPLP is not forecasting to require the entire amount of available financing.[1] However, it has secured financing that would cover a combination of pre-COVID-19 pandemic worst-case scenarios in consideration of cost increases, interest rate increases and construction delays.

The CTIA between WPLP and the Lenders contemplates that each draw will be funded by all of the Lenders, in proportion to the total amount of funding available from each lender. This arrangement resulted from the negotiations between the parties and ensures that the Senior Bank Lenders would be able to lend a reasonable portion of the funds that they have committed, which in turn enables them to offer that funding at competitive rates. As a result of this agreement, approximately 66% (1.34/2.02) of the total project financing will be provided by Ontario, and approximately 34% (0.68/2.02) will be provided by the Senior Bank Lenders. Therefore, as an

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[1] Discussions between WPLP and its EPC contractor over responsibility for costs related to delays in the construction schedule due to the COVID-19 pandemic and related matters are ongoing. The outcome of these discussions could impact the amount of financing required. At this time, WPLP does not know what portion of such EPC contractor cost overruns may be WPLP's responsibility and therefore, is not able to determine the ultimate impact on financing.

example if WPLP ultimately needs to borrow $1.9 billion, then it would get approximately $1.254 billion from Ontario and approximately $646 million from the Senior Bank Lenders.

2. Interest Rates Applicable to Long-Term Debt

The Ontario Facility calculates interest based on a per annum rate comprised of: (a) a variable rate equal to the rate applicable to three-month Treasury bills issued by Ontario at the time of each advance, plus (b) a margin of 50 basis points[2], and (c) an administrative fee of 10 basis points applicable to the amount drawn and outstanding.

The Senior Bank Facility calculates interest based on a per annum rate comprised of: (a) a variable rate equal to the Canadian Dealer Offered Rate ("CDOR") at the time of each advance, plus (b) a margin of 150 basis points, and (c) an administrative fee of 45 basis points on the amount of financing available but not yet advanced.

WPLP has calculated its cost of long-term debt based on the weighted average of the interest rates for the debt facilities described above, consistent with the *Report of the Board 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. Debt issuance costs are amortized over the term of the Ontario Facility and the Senior Bank Facility. The total of 2024 amortization of debt issuance costs and forecasted administrative fees described above are included in the determination of total 2024 interest and fees. The effective 2024 cost of debt rate for each debt facility is then calculated by dividing the forecasted 2024 total interest and fees by the forecasted 2024 12-month average principal balance. Based on this methodology, WPLP's long-term debt rate is calculated to be 5.85% for 2024, as illustrated in Table 2.

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[2] The CTIA specifies that the margin may be increased by 5 basis points under certain conditions, none of which are expected to occur during the 2024 Test Year.

Table 2 – Debt Facilities and Cost of Long-Term Debt

Description	**Lender**	**2024 Principal ($) (12-month Average)**[3]	**2024 Interest & Fees ($)**	**Rate (%)**[4]
Ontario Facility	Province of Ontario	747,827,618	37,207,495	4.98%
Senior Bank Facility	Senior Bank Lenders	450,780,204	32,938,151	7.31%
Total		**1,198,607,822**	**70,145,646**	**5.85%**

WPLP's actual cost of debt will largely be determined by: (a) the timing and amount of advances on WPLP's debt facilities, which will mostly be determined by actual construction progress and associated payment requirements related to WPLP's EPC contract; and (b) the actual Ontario T-Bill and CDOR rates in 2024, which could vary significantly from the forecasts underpinning the calculations in Table 2. WPLP is therefore proposing to continue the Construction Period Interest Costs Variance Account that was established in EB-2021-0134 to record the difference between its forecasted and actual costs of debt during the construction phase of the project, as further detailed in Exhibit H-1-1.

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[3] Principal balance reflects repayment of debt expected when assets go in-service in accordance with WPLP's CTIA.

[4] Interest rate for Ontario facility is based on a T-bill forecasted rates and Senior bank facility is based on forecasted CDOR rates. Senior bank facility includes additional cost mechanisms on unused balance of facility resulting in minimal change as value of principal changes.

Exhibit H, Tab 1, Schedule 1

Overview of Deferral and Variance Accounts

OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

This Exhibit provides an overview of WPLP's existing deferral and variance accounts, identifies the accounts it proposes to continue during the 2024 test year, and sets out WPLP's proposals for modifications to those accounts or new accounts which it seeks approval to establish for the 2024 test year. The disposition of account balances is discussed in Exhibit H-2-1 and H-2-2, with the latter setting out WPLP's proposed approach to the treatment of COVID-related amounts incurred in the construction of the Transmission Project.[1]

A. Existing Accounts and their Continuation

To understand WPLP's existing regulatory accounts, it is helpful to understand the regulatory context for the accounts, including how the accounts were established and have evolved, as well as how they are related to the in-servicing of portions of WPLP's transmission system over time.

1. CWIP Account 2055 (Transmission Development Costs)

On March 23, 2017, the OEB in its Decision and Order in EB-2016-0262 approved WPLP's request to establish a deferral account to capture and record development costs associated with the Transmission Project up to the effective date of the initial transmission rate order for WPLP. Specifically, the OEB authorized the account with an effective date of November 23, 2010 (recognizing the critical role of prior development activities for the project) and required WPLP to establish three sub-accounts (1508.001 through 1508.003), as follows:

- Sub-account 1508.001 was established for WPLP to record its actual development costs incurred for the Wataynikaneyap Transmission Project from November 23, 2010, excluding any start-up and formation costs and costs for electricity distribution-related activities. As set out in the relevant accounting order, development costs include 13 categories of costs, including for engineering, design and procurement, permitting,

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[1] As discussed in this Exhibit H-1-1 and in Exhibit H-2-2, the treatment of COVID-related amounts incurred in the construction of the Transmission Project during 2020 has already been determined by the OEB.

environmental assessments, Aboriginal engagement and communication, project management and regulatory activities.

- Sub-account 1508.002 was established for WPLP to record "all funding amounts received for development activities" related to the Wataynikaneyap Transmission Project from November 23, 2010. In a post-decision letter dated May 12, 2017, OEB staff clarified the scope of this sub-account and its purpose, which was "intended to facilitate informed decision-making by the OEB when considering disposition of the account". In WPLP's initial transmission revenue requirement proceeding (EB-2021-0134), the parties to the OEB-approved Settlement Agreement agreed, and the OEB in approving the Settlement Agreement confirmed, that this subaccount should be discontinued and that the amounts tracked in the subaccount should not be applied as offsets to any development or construction costs.

- Sub-account 1508.003 was established for WPLP to record "carrying charges on net development costs". Given the discontinuation of Sub-account 1508.002, this sub-account continues to be used to record carrying charges but without netting off any amounts.

Balances recorded in the Transmission Development Costs Deferral Account, including each of the three sub-accounts, were reported to the OEB semi-annually, from July 2017 until July 2019, pursuant to the OEB's requirements in EB-2016-0262.

In the LTC proceeding (EB-2018-0190), WPLP requested that the OEB approve an accounting order establishing a Construction Work in Progress (CWIP) Deferral Account into which WPLP would transfer costs from its Transmission Development Costs Deferral Account and record capital costs incurred from the date of the OEB's LTC Decision until such time as the OEB approves the inclusion of those amounts in WPLP's rate base. Instead of approving the proposed account, the OEB directed WPLP to use CWIP Account 2055, which is a standard account in the OEB's Uniform System of Accounts, to record construction costs for future disposition. The OEB also approved WPLP's request to transfer the balance of the Transmission Development Costs

Deferral Account to CWIP Account 2055. As such, WPLP continued to separately track capital costs, funding received and carrying charges within CWIP Account 2055. Since the decision in EB-2021-0134, WPLP has stopped tracking the funding amounts received but has continued to track capital costs and carrying charges in CWIP Account 2055. Moreover, pursuant to the LTC Decision and consistent with the initial rates Decision from EB-2021-0134, WPLP has continued to provide semi-annual reports to the OEB in relation to its CWIP account since October 15, 2019, thereby continuing the reporting previously carried out pursuant to EB-2016-0262.

As identified in Exhibit C-2-1, WPLP is allocating all of its indirect capital costs (including development costs) to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset. As the in-servicing of certain segments of the Transmission System will continue into 2024, CWIP Account 2055 remains relevant. As such, WPLP proposes to continue to use this account in 2024, subject to the following modification.

WPLP is proposing to establish a new sub-account for CWIP Account 2055 to enable tracking of the COVID-related capital costs incurred from 2020 onward which are associated with assets that are either already in service or which will come into service by the end of 2024. As described in Exhibit H-2-1 and Exhibit H-2-2, WPLP is also proposing to transfer the amounts that are currently recorded in the 2021-2023 COVID Construction Costs Deferral Account (2021-2023 CCCDA) to this proposed sub-account.

2. Pikangikum Distribution System Deferral Account

In EB-2018-0267, WPLP received approval to establish a deferral account for the purposes of recording and facilitating the future recovery of costs relating to the temporary operation of its distribution system, which was then being constructed between Red Lake and the Pikangikum First Nation Reserve. WPLP proposed to record costs incurred in respect of the distribution system from the date it went into service until such time as the system is incorporated into and becomes part of WPLP’s Transmission System. WPLP explained that all or substantially all of the capital costs of developing and constructing the distribution system were paid for through federal government funding from Indigenous and Northern Affairs Canada (INAC),[2] and that the account would be used only to record the OM&A costs for the system, as well as any capital costs that may be incurred after the in-service date that are not paid for by the INAC funding. The OEB authorized the requested Pikangikum Distribution System Deferral Account to be established, effective from the in-service date for the distribution system until such time as it is converted to form part of WPLP's Transmission System. The account was established in lieu of setting a distribution revenue requirement and charging distribution rates to Hydro One Remote Communities Inc. (HORCI) during the temporary period that the system is being operated at a distribution voltage. Specifically, the OEB required WPLP to establish six sub-accounts (1508.004 through 1508.009) of Account 1508, Other Regulatory Assets, as follows:

- Sub-account 1508.004 is to record OM&A costs.
- Sub-account 1508.005 is to record capital costs incurred after the distribution system is in service.
- Sub-account 1508.006 is to record depreciation expense.
- Sub-account 1508.007 is to record accumulated depreciation.
- Sub-account 1508.008 is to record OM&A carrying charges.
- Sub-account 1508.009 is to record capital carrying charges.

WPLP's Pikangikum Distribution System was placed in service on December 20, 2018, from which time it operated as a distribution system, supplied by HONI's 44 kV distribution system and providing service to the HORCI distribution system that serves end-use customers in Pikangikum. On May 12, 2023, the Pikangikum Distribution System was converted to being supplied by HONI's 115 kV transmission system and, effective from such date, has formed part of WPLP's Transmission System. While no new capital or OM&A costs will be recorded in the account during 2024, WPLP proposes to continue this account until the final balance has been disposed of in a future transmission revenue requirement application to the OEB. As WPLP has incurred costs in respect of the Pikangikum Distribution System up to the date of conversion on May 12, 2023,

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[2] Currently Indigenous Services Canada (ISC).

the final audited balance is not expected to be disposed of until WPLP's 2025 transmission rate application. Therefore, as described in Exhibit H-2-1, WPLP is seeking partial disposition of the audited balance as at December 31, 2022, plus forecasted deferral account carrying charges, and proposes to continue this account in 2024.

3. In-Service Date Variance Account (ISDVA)

In EB-2021-0134, WPLP received approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: In-Service Date Variance Account for the purpose of recording the difference between WPLP's approved revenue requirement based on forecasted in-service dates for the various lines/stations comprising its Transmission System and its revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. The ISDVA was established as a symmetrical account, such that it tracks higher revenue requirements for earlier in-service dates that may be achieved, as well as lower revenue requirements if later in-service dates occur. In effect, the purpose of the ISDVA is to true-up WPLP's revenue requirement to ensure ratepayers do not end up paying for transmission service they do not ultimately receive, while also providing WPLP with appropriate cost recovery if it is able to provide transmission service on parts of its system earlier than forecast.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the ISDVA with an effective date of January 1, 2022. Moreover, continuation of this account was approved in EB-2022-0149. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

In requesting the ISDVA, WPLP stated that it expected this account would be maintained until after WPLP's entire Transmission System is in service. Given that the Transmission Project is still under construction, and transmission assets will be coming into service in the 2024 test year, WPLP proposes to continue using the ISDVA to record differences between its approved revenue requirement based on the forecasted in-service dates in 2024 for the various lines/stations comprising its Transmission System and its revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. As such, WPLP is seeking partial disposition of the audited balance as at December 31, 2022 (as described in Exhibit H-2-1), along with forecasted carrying charges, and will seek disposition of the final balance of the ISDVA in a future application.

For clarity, when calculating its revenue requirement based on the actual in-service dates for each asset for purposes of determining the amounts to record in this account for 2024, WPLP plans to use the same cost of capital rates as those which are ultimately approved in this Application and would record any difference between its approved revenue requirement and its recalculated revenue requirement in the ISDVA.

4. Construction Period Interest Costs Variance Account (CPICVA)

In EB-2021-0134, WPLP received approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: Construction Period Interest Costs Variance Account for the purpose of recording the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in that application and WPLP’s actual effective interest rate on long-term debt during the construction period (the "Interest Cost Differential"). Due to the variable-rate debt facilities WPLP secured with Ontario and Senior Bank Lenders to finance the Transmission Project, there could be differences in interest rates that could lead to material variances between the interest costs included in rates and WPLP’s actual interest costs. The CPICVA was established as a symmetrical account, such that it tracks higher revenue requirements for higher interest costs, as well as lower revenue requirements for lower interest costs.

The Interest Cost Differential in respect of an asset is recorded from the actual in-service date of the asset[3] until the effective date of an approved WPLP revenue requirement that reflects WPLP's cost of long-term debt financing for that asset. As WPLP relies on project specific financing for the duration of the construction period and will transition to long-term debt financing after all

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[3] Prior to the in-service date, interest will be calculated on WPLP's CWIP account balance, in accordance with the OEB's Decision and Order in EB-2018-0190 and will be recorded as a carrying cost within the CWIP account.

assets comprising the Line to Pickle Lake and Remote Connection Line are in service,[4] it is expected based on the current project schedule that Interest Cost Differentials will continue to be recorded up to and during the 2025 rate year, with WPLP's 2026 revenue requirement reflecting the cost of long-term debt.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the CPICVA with an effective date of January 1, 2022. Moreover, continuation of this account was approved in EB-2022-0149. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

WPLP proposes to continue using the CPICVA to record differences between the effective interest rate for long-term debt approved in this Application and WPLP's actual effective interest rate on long-term debt in 2024, as the Transmission Project will still be under construction and interest rate differences may continue to arise. WPLP is seeking partial disposition of the audited balance as at December 31, 2022 (as described in Exhibit H-2-1), including forecasted carrying charges, and will seek disposition of the final balance of the CPICVA in a future application.

5. Deferred Contingency Deferral Account (DCDA)

Pursuant to the approved Settlement Agreement in EB-2021-0134, the parties agreed that WPLP would remove and defer recovery of $48,075,777 in forecasted contingency amounts from its 2022 in-service asset additions used to calculate year-end rate base (such amount referred to as the "Deferred Contingency Amount"). The parties also agreed that WPLP would establish a new deferral account, being Account 1508 (Other Regulatory Assets), Sub Account: Deferred Contingency Deferral Account, effective January 1, 2022, to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP would seek to recover, to the extent the forecasted contingency is actually realized, subject to OEB review in a future transmission rate application. The amount eligible to be recorded in the DCDA was limited to the revenue requirement impact attributed to contingency costs to a maximum of $48,075,777 for

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[4] The process of transitioning to long-term financing is expected to take approximately 6-9 months once all project components are in-service.

2022. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

Pursuant to the approved Settlement Agreement in EB-2022-0149, the parties agreed with WPLP's proposal to use the same approach to contingency in 2023 as was approved for 2022 in EB-2021-0134, subject to the modification that the DCDA would also be used to record the revenue requirement impact attributable to contingency costs associated with 2023 in-service additions. WPLP therefore removed and deferred $17,299,725 of contingency from the 2023 rate base and will record the revenue requirement impact associated with that contingency amount, to the extent it is realized and does not exceed the amount removed from 2023 rate base, in the DCDA. The amount eligible to be recorded in the DCDA is therefore limited to the revenue requirement impact attributable to contingency costs to a maximum of $48,075,777 in respect of 2022 and $17,299,725 in respect of 2023, corresponding to the forecasted contingency amounts which were removed and deferred from the 2022 and 2023 in-service additions used to calculate WPLP's 2022 and 2023 rate bases. In EB-2022-0149, WPLP agreed to establish separate sub-accounts within the DCDA to separately record principal and interests amounts related to the Line to Pickle Lake and the Remote Connection Lines, for each of 2022 and 2023.

As the actual amount of contingency realized in 2023 is not yet available, and WPLP has additional forecasted contingency amounts of $64,582,124 associated with its planned 2024 in-service asset additions used to calculate year-end rate base, WPLP proposes to continue this account in 2024. WPLP is seeking partial disposition of the audited balance as at December 31, 2022 (as described in Exhibit H-2-1), as well as forecasted carrying charges, and proposes to continue to use the DCDA to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP will seek to recover, to the extent the forecasted contingency is actually realized, limited to the revenue requirement impact attributable to contingency costs for 2023 and 2024, to a maximum of $81,881,849.

6. COVID Construction Costs Deferral Account (CCCDA)

On April 13, 2021, the OEB issued a letter in EB-2020-0133 indicating its determination that the guidelines being developed for the generic Account 1509 - Impacts Arising from the COVID-19 Emergency will not apply to greenfield utilities, including WPLP. The OEB recognized that the circumstances and impacts of the pandemic on greenfield utilities is distinct, and that any ratemaking implications of the pandemic should therefore be determined through each greenfield utility's rate proceedings.

In EB-2021-0134, WPLP requested approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: COVID Construction Costs Deferral Account to record its incremental development and construction costs resulting from the COVID-19 pandemic. WPLP explained that the CCCDA was required to facilitate the recovery of WPLP's incremental COVID-related Project costs as an expense rather than as a cost of capital in its revenue requirement, as further described in Exhibit H-2-2.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the CCCDA with an effective date of March 10, 2020. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines. The approved Settlement Agreement also provided that WPLP would record in the account and over a 4-year period dispose of its COVID costs incurred to December 31, 2020 (i.e. 25% in each of 2022, 2023, 2024 and 2025). In the approved Settlement Agreement in EB-2022-0149, the parties agreed that WPLP would continue to recover the 2020 COVID costs as recorded in the CCCDA over the remaining three years of the disposition period approved in EB-2021-0134 (2023, 2024 and 2025). The parties also agreed that WPLP would not record in the CCCDA or dispose of any incremental year-end 2021 COVID costs in 2023, but instead that it would record such costs and any incremental year-end 2022 and 2023 COVID costs in a new "2021-2023 COVID Construction Costs Deferral Account", as described below. WPLP is therefore seeking disposition of the applicable portion of the audited balance of the CCCDA as at December 31, 2022 (as described in Exhibit H-2-1), as well as forecasted carrying charges.

7. 2021-2023 COVID Construction Costs Deferral Account

In approving the Settlement Agreement in EB-2022-0149, the OEB authorized the establishment of a new deferral account, being Account 1508, Other Regulatory Assets – Sub Account "2021-2023 COVID Construction Costs Deferral Account" (the "2021-2023 CCCDA"), effective January 1, 2021. WPLP is authorized to record in the account incremental year-end COVID costs from 2021 to 2023, with prudence and the approach to disposition of such amounts (either as capital or as an OM&A expense) to be determined at the time of disposition in a future rate application once the COVID cost information for these years is known, and with the applicable carrying charges to be consistent with the approach to disposition that is ultimately approved at the time of disposition (i.e. at the applicable CWIP rate if ultimately treated as capital).

Pursuant to the Settlement Agreement in EB-2022-0149, upon establishing the 2021-2023 CCCDA, WPLP transferred incremental COVID-related costs incurred on or after January 1, 2021, previously recorded in the CCCDA, to the 2021-2023 CCCDA. WPLP has recorded COVID-related construction costs incurred thereafter directly in the 2021-2023 CCCDA. Furthermore, on an interim basis pending determination of the approach to disposition, WPLP has recorded interest on the balance in the 2021-2023 CCCDA using the OEB's prescribed interest rate for deferral and variance accounts.

In the current Application, WPLP is proposing to dispose of the 2023 year-end forecasted balance of the 2021-2023 CCCDA as capital, to update the recorded carrying charges to reflect AFUDC, and to continue this account subject to certain modifications. More particularly, WPLP is proposing to transfer the 2021-2023 CCCDA audited (to December 31, 2022) and unaudited (from January 1, 2023 to December 31, 2023) 2023 year-end forecast balance, together with applicable AFUDC, to CWIP Account 2055 on December 31, 2023. WPLP is also seeking to continue the account to enable the tracking of any additional COVID-related capital costs that WPLP may recognize as having been incurred by WPLP upon conclusion of the commercial discussions that are ongoing with its EPC contractor and which may relate to the 2021-2023 period. Furthermore, WPLP is requesting modifications to the account to specify that any amounts recorded in the account will be treated as capital and by expanding the scope of the account by one year to enable tracking of COVID-related capital costs (including, for greater certainty, legal costs and costs relating to access issues in the Whitefeather Forest area[5]) relating to 2020 (in addition to such costs relating to 2021-2023) that WPLP may recognize as having been incurred upon conclusion of the commercial discussions that are ongoing with its EPC contractor. A draft revised accounting order is provided in Appendix 'A'. WPLP's proposed approach to the disposition of the transferred amounts from CWIP Account 2055 to rate base is described in Exhibit H-2-1. See also Exhibit H-2-2 and the section below regarding the proposed EPC COVID-Related Costs Deferral Account.

8. Construction Period OM&A Variance Account

In approving the Settlement Agreement in EB-2022-0149, the OEB authorized the establishment of a new variance account, being Account 1508, Other Regulatory Assets – Sub Account "Construction Period OM&A Variance Account", effective January 1, 2023. The account is asymmetrical, to the benefit of ratepayers, and the amounts eligible to be recorded in the Construction Period OM&A Variance Account are the differences, if any, between WPLP's forecast annual OM&A expenses as approved by the OEB and its actual OM&A expenses for the corresponding year (in each case excluding depreciation expense and income tax expense), during the period that WPLP's transmission project is under construction. Any shortfall in actual spending relative to forecast, together with applicable interest on the principal balance recorded, will be returned to ratepayers in a future rate proceeding.[6] WPLP also agreed to establish separate sub-accounts within the Construction Period OM&A Variance Account to separately record principal and interests amounts related to the Line to Pickle Lake and the Remote Connection Lines. As the account is intended to be in place for the duration of the construction period, WPLP proposes that this account be continued for the 2024 test year.

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[5] See Exhibit H-1-1, Appendix 'A', Footnote 2.

[6] WPLP notes that while it has a budget for donations, those costs are not included in the calculation of the balance in this account, and WPLP does not otherwise seek to recover any amounts relating to donations from ratepayers.

B. Continuity Schedule for Existing Accounts

Table 1, below, provides a summary of WPLP's existing deferral and variance account balances, including each of the sub-accounts that remain in effect as described above, as at December 31, 2022. Continuity schedules for WPLP's existing regulatory accounts from their inception up to and including their audited balances as at December 31, 2022 have been filed in Excel format with the application as "H-1-1_WPLP Deferral and CWIP Continuity 2024.xlsx".

Table 1: Existing Regulatory Account Balances (December 31, 2022)

Account	**Principal**	**Carrying Charges (Net)**	**Total**
2055 – CWIP: Transmission Development Costs	$602,804,643	$49,522,299	$652,326,942
1508 – Pikangikum Distribution System Deferral Account	$2,826,420	$111,305	$2,937,725
1508 – In-Service Date Variance Account	($15,009,351)	($185,891)	($15,195,242)
1508 – Construction Period Interest Costs Variance Account	$3,383,187	$12,595	$3,395,782
1508 – COVID Construction Costs Deferral Account	$13,148,917	$293,110	$13,442,027
1508 – Deferred Contingency Deferral Account	$21,994	$87	$22,082
1508 – 2021-2023 COVID Construction Costs Deferral Account	$68,174,054	$1,009,776	$69,183,830

WPLP confirms that it calculated monthly carrying charges for its deferral accounts by applying the OEB's prescribed interest rates for deferral and variance accounts[7] to the monthly opening principal balances in each account. In accordance with the LTC Decision,[8] WPLP applied its effective borrowing cost to determine carrying charges for CWIP Account 2055, since its cost of debt has been lower than the OEB's published CWIP interest rates.

C. Proposed New Accounts

WPLP is proposing in the current Application to establish two new regulatory accounts, as follows.

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[7] See: https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

[8] EB-2018-0190, Decision and Order, April 1, 2019 (Revised April 29, 2019), p. 28

1. Federal CIAC Variance Account

WPLP is requesting approval to establish a new “Federal CIAC Variance Account”, effective January 1, 2024, for the purpose of recording the revenue requirement impact of the difference, if any, between WPLP’s forecasted date of the Contribution in Aid of Construction (“CIAC”) funds being distributed to WPLP pursuant to the Federal Funding Framework and the actual date of the CIAC funds being distributed to WPLP. WPLP forecasts that the date the CIAC funds will be distributed to WPLP pursuant to the Federal Funding Framework is December 31, 2024. However, the actual date the funds will be distributed is subject to a number of variables and cannot be determined with certainty at this time. WPLP proposes that this account be symmetrical, such that it would track higher revenue requirement amounts for recovery by WPLP if the CIAC funds are distributed later than expected, as well as reduced revenue requirement amounts to be returned to customers if the CIAC funds are distributed earlier than expected. As the CIAC funds would be provided in respect of the Remote Connection Lines, any recovery of amounts by WPLP or return of amounts to customers arising from the account will be recovered or returned, as applicable, only through the portion of WPLP’s revenue requirement that relates to the Remote Connection Lines. The need for this account, and the reasons it meets the OEB's eligibility criteria for establishing a new account, are as follows.

In WPLP’s view, the proposed account is the most prudent approach for ratepayers while also being fair to WPLP by providing an opportunity for appropriate cost recovery in the event the CIAC is received later than the forecast date and by providing an opportunity for returning excess amounts to customers in the event the CIAC is received earlier than the forecast date. The amounts recorded in the account would be clearly outside of the base upon which WPLP’s revenue requirement will be derived because WPLP’s rates for 2024 will be determined using December 31, 2024 as the forecasted date upon which the CIAC will be received. Moreover, the resulting variances could be material due to the magnitude of the CIAC. For example, if based on the forecasted total project costs of $1,906 million[9] the CIAC is forecasted to be $865 million, then a

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[9] Forecasted total project costs from Table 3 in Exhibit B-1-5.

one-month difference in when it is received could have a revenue requirement impact of approximately $1.4 million due to the timing impact on depreciation.

A draft accounting order for the proposed Federal CIAC Variance Account is provided in Appendix ‘B’.

2. EPC COVID-Related Costs Deferral Account

WPLP is requesting approval to establish, effective January 1, 2024, a new EPC COVID-Related Costs Deferral Account (“EPC COVID Account”) to record costs, including applicable AFUDC, incurred and to be incurred by WPLP under its EPC Contract that relate to 2024 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area[10], other than any such costs that are related to the 2020-2023 period and which would instead be recorded in the 2021-2023 CCCDA. As WPLP and Valard continue to engage in commercial discussions regarding COVID cost and schedule impacts, there continues to be a significant degree of uncertainty regarding any amounts that WPLP may ultimately bear responsibility for, as well as with respect to the costs (including legal costs) associated with WPLP’s consideration, negotiation and potential settlement and/or other resolution of COVID cost and schedule impacts. WPLP believes that any costs it may ultimately be responsible for in relation to anticipated EPC contractor claims, which are potentially material, would be capital expenditures that form part of the Transmission Project and therefore, once the amounts are settled or otherwise determined on a final basis as between the parties, WPLP would propose that those capital costs (if any) be added to WPLP’s rate base.

The proposed EPC COVID Account is appropriate because it would provide an opportunity for WPLP to seek appropriate cost recovery, in respect of 2024 or later, once the quantum of any amount for which WPLP may be responsible is settled or otherwise determined on a final basis as between WPLP and Valard (with the comparable amounts in respect of 2020-2023 being recorded

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[10] See Exhibit H-1-1, Appendix ‘C’, Footnote 1.

in the 2021-2023 CCCDA based on the proposed modifications thereto). Until such time, any such amounts remain uncertain. The amounts to be recorded in the account would be clearly outside of the base upon which WPLP's revenue requirement will be derived because WPLP has not included in its proposed revenue requirement for 2024 (or for any prior year) any of the COVID cost or schedule impacts that are the subject of the ongoing commercial negotiations, or any costs for considering or negotiating those amounts.

A draft accounting order for the proposed EPC COVID Account is provided in Appendix 'C'.

Wataynikaneyap Power LP
CWIP Interest Summary

Month	Opening CWIP Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance	Notes
Transfer	57,090,899	2,015,760.17	2,015,760.17	(1)/(2)
Apr-19	57,587,789	-	2,015,760.17	
May-19	59,287,570	-	2,015,760.17	
Jun-19	60,358,779	-	2,015,760.17	
Jul-19	61,811,351	-	2,015,760.17	
Aug-19	63,619,732	-	2,015,760.17	
Sep-19	65,821,561	-	2,015,760.17	
Oct-19	73,400,434	86,830.26	2,102,590.43	(3)
Nov-19	88,053,404	783,635.59	2,886,226.02	
Dec-19	95,395,592	744,121.72	3,630,347.74	
Jan-20	103,971,328	769,413.73	4,399,761.47	
Feb-20	128,483,008	747,309.03	5,147,070.50	
Mar-20	157,497,178	820,978.16	5,968,048.66	
Apr-20	206,020,543	788,180.57	6,756,229.23	
May-20	231,607,302	752,421.56	7,508,650.79	
Jun-20	253,369,453	724,715.84	8,233,366.63	
Jul-20	274,877,061	766,889.50	9,000,256.13	
Aug-20	295,759,627	788,913.66	9,789,169.79	
Sep-20	327,588,650	771,005.50	10,560,175.29	
Oct-20	363,722,915	837,528.93	11,397,704.22	
Nov-20	405,521,404	809,468.74	12,207,172.96	
Dec-20	433,459,979	818,820.59	13,025,993.55	
Jan-21	486,216,556	873,940.62	13,899,934.17	
Feb-21	538,781,461	812,064.22	14,711,998.39	
Mar-21	644,161,788	919,216.96	15,631,215.35	
Apr-21	700,621,393	927,987.93	16,559,203.28	
May-21	710,116,892	1,027,149.96	17,586,353.24	
Jun-21	737,799,710	1,061,331.63	18,647,684.87	
Jul-21	748,459,691	1,140,964.70	19,788,649.57	
Aug-21	762,691,842	1,162,273.81	20,950,923.38	
Sep-21	813,244,413	965,218.86	21,916,142.24	
Oct-21	839,804,928	1,207,895.26	23,124,037.50	
Nov-21	863,560,703	1,161,128.19	24,285,165.69	
Dec-21	889,733,556	1,235,374.59	25,520,540.28	
Jan-22	915,342,118	1,179,095.47	26,699,635.75	
Feb-22	958,712,782	1,118,976.71	27,818,612.46	
Mar-22	1,005,671,491	1,394,136.57	29,212,749.03	
Apr-22	1,063,672,636	1,397,583.68	30,610,332.71	
May-22	1,094,047,024	1,863,428.67	32,473,761.38	
Jun-22	1,115,653,654	2,167,212.86	34,640,974.24	
Jul-22	1,169,544,338	2,709,170.53	37,350,144.77	
Aug-22	903,189,871	3,019,426.52	40,369,571.29	
Sep-22	927,109,676	2,372,577.29	42,742,148.58	
Oct-22	670,664,248	2,018,053.52	44,760,202.10	
Nov-22	594,741,323	2,478,873.37	47,239,075.47	
Dec-22	602,803,994	2,283,872.20	49,522,947.67	

Notes

(1) Initial transfer from development deferral account to CWIP, pursuant to the OEB's Decision and Order in EB-2018-0190.

(2) In accordance with the OEB's decision and order in EB-2021-0134, WPLP reversed carrying charges on Third Party Funding that was previously net against carrying charges on development costs.

(3) In accordance with the OEB's decision and order in EB-2018-0190, WPLP used its actual cost of debt in respect of CWIP interest rates, starting at financial close in October 2019

Reconciliation to Fixed Asset Continuity Schedule

		Reference
CWIP Principal (Net)	602,803,994	Per Above
Carrying Charges	49,522,948	Per Above
	652,326,942	
CWIP per FAC	**915,254,096**	

Reconciliation to Audited Financial Statements

		Reference
CWIP Principal (Net)	602,803,994	Per Above
Carrying Charges	49,522,948	Per Above
	652,326,942	
CWIP per AFS	**652,326,942**	

Wataynikaneyap Power LP

COVID Deferral Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Dec-20	17,399,652.04	-	-
Jan-21	17,399,652.04	8,423.34	8,423.34
Feb-21	17,399,652.04	7,608.18	16,031.52
Mar-21	17,399,652.04	8,423.34	24,454.85
Apr-21	17,399,652.04	8,151.62	32,606.47
May-21	17,399,652.04	8,423.34	41,029.81
Jun-21	17,399,652.04	8,151.62	49,181.43
Jul-21	17,399,652.04	8,423.34	57,604.77
Aug-21	17,399,652.04	8,423.34	66,028.10
Sep-21	17,399,652.04	8,151.62	74,179.72
Oct-21	17,399,652.04	8,423.34	82,603.06
Nov-21	17,399,652.04	8,151.62	90,754.68
Dec-21	17,399,652.04	8,423.34	99,178.02
Jan-22	17,399,652.04	8,423.34	107,601.36
Feb-22	17,399,652.04	7,608.18	115,209.53
Mar-22	17,399,652.04	8,423.34	123,632.87
Apr-22	17,062,632.15	14,587.11	138,219.98
May-22	16,561,020.26	14,781.38	153,001.36
Jun-22	16,059,408.37	13,884.03	166,885.39
Jul-22	15,557,796.48	30,006.89	196,892.29
Aug-22	15,056,184.59	29,069.64	225,961.92
Sep-22	14,554,572.59	27,224.88	253,186.80
Oct-22	14,052,962.31	47,838.69	301,025.49
Nov-22	13,551,350.67	44,699.97	345,725.46
Dec-22	13,049,739.03	46,562.25	392,287.71

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	13,049,739
Carrying Charges	392,288
	13,442,027
Balance per AFS	**13,442,027**

Wataynikaneyap Power LP
COVID Deferral Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Dec-20	-	-	-
Jan-21	150,179.83	-	-
Feb-21	3,523,458.88	65.67	65.67
Mar-21	7,367,059.70	1,705.74	1,771.41
Apr-21	8,563,793.21	3,451.42	5,222.82
May-21	11,043,423.67	4,145.81	9,368.64
Jun-21	13,313,577.88	5,173.77	14,542.41
Jul-21	14,722,805.35	6,445.23	20,987.64
Aug-21	16,102,841.99	7,127.45	28,115.09
Sep-21	17,482,670.82	7,544.07	35,659.16
Oct-21	21,575,163.13	8,463.53	44,122.69
Nov-21	23,910,090.43	10,107.82	54,230.51
Dec-21	41,931,998.62	11,575.10	65,805.61
Jan-22	43,186,712.64	20,299.68	86,105.29
Feb-22	43,477,451.05	18,883.83	104,989.13
Mar-22	47,674,656.51	21,047.85	126,036.98
Apr-22	48,322,366.15	39,968.34	166,005.32
May-22	48,382,360.19	41,861.73	207,867.05
Jun-22	48,431,713.18	40,561.65	248,428.70
Jul-22	49,809,037.46	90,494.32	338,923.03
Aug-22	49,861,688.67	93,067.85	431,990.87
Sep-22	50,111,552.77	90,160.86	522,151.73
Oct-22	50,155,530.16	164,709.12	686,860.86
Nov-22	50,321,851.12	159,535.81	846,396.66
Dec-22	68,174,053.93	163,379.34	1,009,776.01

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	68,174,054
Carrying Charges	1,009,776
	69,183,830
Balance per AFS	**69,183,830**

Wataynikaneyap Power LP
Pikangikum Distribution Deferral Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Dec-18	108,159.41	-	-
Jan-19	145,056.55	225.06	225.06
Feb-19	172,176.02	272.63	497.69
Mar-19	272,626.61	358.27	855.95
Apr-19	303,312.06	488.49	1,344.44
May-19	334,938.12	561.58	1,906.03
Jun-19	355,151.82	600.14	2,506.16
Jul-19	370,571.84	657.57	3,163.73
Aug-19	711,972.86	686.12	3,849.84
Sep-19	726,801.05	1,275.70	5,125.54
Oct-19	751,934.44	1,345.68	6,471.22
Nov-19	1,348,533.77	1,347.30	7,818.52
Dec-19	1,623,685.55	2,496.82	10,315.34
Jan-20	1,635,676.96	2,998.05	13,313.39
Feb-20	1,667,863.61	2,825.34	16,138.73
Mar-20	1,718,577.99	3,079.62	19,218.36
Apr-20	1,747,086.53	3,070.90	22,289.26
May-20	1,846,096.29	3,225.90	25,515.16
Jun-20	1,939,259.67	3,298.76	28,813.93
Jul-20	1,955,308.02	936.25	29,750.18
Aug-20	2,221,530.08	944.00	30,694.17
Sep-20	2,251,947.50	1,037.93	31,732.10
Oct-20	2,293,724.35	1,087.21	32,819.31
Nov-20	2,329,952.37	1,071.66	33,890.97
Dec-20	2,011,949.77	1,124.87	35,015.84
Jan-21	2,040,934.87	969.47	35,985.31
Feb-21	2,120,369.88	892.42	36,877.73
Mar-21	2,152,695.85	1,026.49	37,904.23
Apr-21	2,184,263.88	1,008.52	38,912.75
May-21	2,238,446.79	1,057.42	39,970.17
Jun-21	2,259,365.62	1,048.70	41,018.87
Jul-21	2,484,595.28	1,093.78	42,112.65
Aug-21	2,741,691.72	1,202.82	43,315.47
Sep-21	2,934,074.19	1,284.46	44,599.93
Oct-21	3,133,946.65	1,420.41	46,020.34
Nov-21	3,156,654.55	1,468.23	47,488.58
Dec-21	3,194,911.44	1,528.17	49,016.74
Jan-22	3,223,707.33	1,539.36	50,556.10
Feb-22	3,301,516.86	1,409.60	51,965.70
Mar-22	3,332,428.88	1,598.30	53,563.99
Apr-22	3,533,430.10	2,793.76	56,357.76
May-22	3,297,209.85	3,061.02	59,418.77
Jun-22	3,067,294.77	2,764.24	62,183.01
Jul-22	3,192,718.43	5,731.22	67,914.23
Aug-22	3,014,064.09	5,965.57	73,879.80
Sep-22	3,488,461.47	5,450.09	79,329.89
Oct-22	3,287,959.96	11,466.05	90,795.94
Nov-22	3,057,515.23	10,458.42	101,254.35
Dec-22	2,826,419.78	10,049.59	111,303.94

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	2,826,420
Carrying Charges	111,304
	2,937,724
Balance per AFS	**2,937,724**

Wataynikaneyap Power LP
Construction Period Interest Costs Variance Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Jan-22	-	-	-
Feb-22	-	-	-
Mar-22	-	-	-
Apr-22	-	-	-
May-22	-	-	-
Jun-22	30.97	-	-
Jul-22	138.78	0.06	0.06
Aug-22	144,405.12	0.26	0.32
Sep-22	535,444.51	261.12	261.44
Oct-22	1,095,332.83	1,759.93	2,021.37
Nov-22	2,156,946.50	3,484.06	5,505.43
Dec-22	3,383,187.02	7,089.56	12,594.99

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	3,383,187
Carrying Charges	12,595
	3,395,782
Balance per AFS	**3,395,782**

Wataynikaneyap Power LP
Deferred Contingency Deferral Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Jan-22	-	-	-
Feb-22	-	-	-
Mar-22	-	-	-
Apr-22	-	-	-
May-22	-	-	-
Jun-22		-	-
Jul-22			-
Aug-22			-
Sep-22	4,044.45	-	-
Oct-22	9,512.59	8.57	8.57
Nov-22	14,771.60	30.26	38.83
Dec-22	21,994.14	48.56	87.39

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	21,994
Carrying Charges	87
	22,082
Balance per AFS	**22,082**

Wataynikaneyap Power LP
In-Service Date Variance Account Summary

Month	Closing Deferral Acct Balance	Carrying Charges by Month	Cumulative Carrying Charges Balance
Jan-22	-	-	-
Feb-22	-	-	-
Mar-22	-	-	-
Apr-22	- 572,293.69	-	-
May-22	- 2,250,137.17	- 495.78	- 495.78
Jun-22	- 4,575,239.93	- 1,886.41	- 2,382.19
Jul-22	- 8,144,925.82	- 8,548.80	- 10,930.99
Aug-22	- 11,190,168.34	- 15,218.74	- 26,149.73
Sep-22	- 13,210,204.82	- 20,234.28	- 46,384.01
Oct-22	- 14,687,181.01	- 43,419.95	- 89,803.96
Nov-22	- 15,020,399.98	- 46,717.31	- 136,521.27
Dec-22	- 15,009,350.52	- 49,369.79	- 185,891.06

Reconcilitaion to Audited Financial Statements

Deferral Account Principal	- 15,009,351
Carrying Charges	- 185,891
	- 15,195,242
Balance per AFS	**- 15,195,242**

APENDIX A

2021-2023 COVID Construction Costs Deferral Account - Draft Revised Accounting Order

DRAFT REVISED ACCOUNTING ORDER – WATAYNIKANEYAP POWER LP 2021-2023 COVID CONSTRUCTION COSTS DEFERRAL ACCOUNT

Wataynikaneyap Power LP (WPLP) shall modify the scope of its "2021-2023 COVID Construction Costs Deferral Account" (2021-2023 CCCDA), which currently authorizes it to record incremental year-end costs from 2021 to 2023 which are directly attributable to the COVID-19 pandemic (the "Incremental COVID Construction Costs").[1] As of January 1, 2024, WPLP shall also be permitted to record in the 2021-2023 CCCDA any additional COVID-related costs (including, for greater certainty, legal costs and costs relating to access issues in the Whitefeather Forest area[2]) that WPLP may recognize as having been incurred by WPLP upon conclusion of the commercial discussions that are ongoing with its EPC contractor, which costs may relate to 2020 (in addition to any such costs relating to 2021-2023).[3] Any such amounts will be treated as capital costs. The prudence of the amounts recorded will be determined at the time of disposition in a future rate application once WPLP's COVID-related capital cost information for these years is known.

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[1] For greater certainty, this account is distinct from WPLP's existing COVID Construction Costs Deferral Account (CCCDA), which applies exclusively to incremental COVID costs from 2020 for which disposition as an OM&A expense, over a 4-year period from 2022-2025, was approved in EB-2021-0134.

[redacted]

[3] For greater certainty, no amounts shall be recorded in the 2021-2023 CCCDA (as hereby modified) if such amounts have previously been recorded in the CCCDA.

The 2021-2023 CCCDA will continue to be known as Account 1508, Other Regulatory Assets – Sub Account "2021-2023 COVID Construction Costs Deferral Account", but will be subject to the modified scope as of January 1, 2024 and will thereafter permit amounts to be recorded effective from January 1, 2020. WPLP will record interest on the balance in the sub-account using WPLP's actual cost of debt (AFUDC). Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. WPLP will maintain separate sub-accounts within the 2021-2023 CCCDA in order to separately record principle and interest amounts related to the Line to Pickle Lake and the Remote Connection Lines.

The balance in this account will be brought forward for disposition in future proceedings. The following outlines the proposed accounting entries for this deferral account:

USofA#	Account Description
CR 2205	Accounts Payable
DR 1508	Other Regulatory Assets – Sub Account "2021-2023 COVID Construction Costs Deferral Account"

- *To record any Incremental COVID Construction Costs incurred in 2020, 2021, 2022 or 2023*

USofA#	Account Description
CR 4405	Interest and Dividend Income
DR 1508	Other Regulatory Assets – Sub Account "2021-2023 COVID Construction Costs Deferral Account"

- *To record interest on the principal balance of the deferral account*

APENDIX B

Federal CIAC Variance Account – Draft Accounting Order

DRAFT ACCOUNTING ORDER – WATAYNIKANEYAP POWER LP

FEDERAL CIAC VARIANCE ACCOUNT

Wataynikaneyap Power LP (WPLP) shall establish a new "Federal CIAC Variance Account" to record the revenue requirement impact of the difference, if any, between WPLP's forecasted date of the Contribution in Aid of Construction ("CIAC") funds being distributed to WPLP pursuant to the Federal Funding Framework and the actual date of the CIAC funds being distributed to WPLP.

WPLP forecasts that the date the CIAC funds will be distributed to WPLP pursuant to the Federal Funding Framework is December 31, 2024. However, the actual date the funds will be distributed is subject to a number of variables and cannot be determined with certainty at this time. The Federal CIAC Variance Account shall be symmetrical, such that it would track higher revenue requirement amounts for recovery by WPLP if the CIAC funds are distributed later than expected, as well as reduced revenue requirement amounts to be returned to customers if the CIAC funds are distributed earlier than expected. As the CIAC funds would be provided in respect of the Remote Connection Lines, any recovery of amounts by WPLP or return of amounts to customers arising from the account shall be recovered or returned, as applicable, only through the portion of WPLP's revenue requirement that relates to the Remote Connection Lines.

The account will be established as Account 1508, Other Regulatory Assets – Sub Account "Federal CIAC Variance Account", effective January 1, 2024. WPLP will record interest on the balance in the sub-account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The balance in this account will be brought forward for disposition in a future proceeding.

The following outlines the proposed accounting entries for this deferral account:

USofA#	Account Description
DR/CR 1508	Other Regulatory Assets – Sub Account "Federal CIAC Variance Account"
CR/DR 4110	Transmission Service Revenue

- *To record the Federal CIAC Revenue Requirement Differential*

USofA#	Account Description
DR/CR 1508	Other Regulatory Assets – Sub Account "Federal CIAC Variance Account"
CR/DR 6035	Other Interest Expense

- *To record interest on the principal balance of the variance account*

APENDIX C

EPC COVID-Related Costs Deferral Account – Draft Accounting Order

DRAFT ACCOUNTING ORDER – WATAYNIKANEYAP POWER LP

EPC COVID-RELATED COSTS DEFERRAL ACCOUNT

Wataynikaneyap Power LP (WPLP) shall establish a new EPC COVID-Related Costs Deferral Account to record costs incurred and to be incurred by WPLP in respect of anticipated claims for cost and schedule relief under its EPC contract that relate to 2024 or later and which are in relation to COVID and related access issues in the Whitefeather Forest,[1] including costs (such as legal costs) associated with WPLP's consideration, negotiation and potential settlement and/or other resolution of COVID-related costs ("EPC COVID Account").

The EPC COVID Account will be established as Account 1508, Other Regulatory Assets – Sub Account "EPC COVID-Related Costs Deferral Account", effective January 1, 2024. WPLP will record interest on the balance in the sub-account using WPLP's actual cost of debt (AFUDC). Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. WPLP will establish separate sub accounts within the EPC COVID Account in order to separately record principle and interest amounts related to the Line to Pickle Lake and the Remote Connection Lines.

The balance in this account will be brought forward for disposition in future proceedings.

[redacted]

The following outlines the proposed accounting entries for this deferral account:

USofA#	Account Description
CR 2205	Accounts Payable
DR 1508	Other Regulatory Assets – Sub Account “EPC COVID-Related Costs Deferral Account”

- *To record any EPC COVID-Related Costs incurred or to be incurred after the deferral account is established*

USofA#	Account Description
CR 4405	Interest and Dividend Income
DR 1508	Other Regulatory Assets – Sub Account “EPC COVID-Related Costs Deferral Account”

- *To record interest on the principal balance of the deferral account*

Exhibit H, Tab 2, Schedule 1

Disposition of Deferral and Variance Accounts

DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

This Exhibit describes WPLP's proposals for the disposition of amounts recorded in its existing regulatory accounts, which are described in Exhibit H-1-1 and are as follows:

- Pikangikum Distribution System Deferral Account;
- In-Service Date Variance Account ("ISDVA");
- Construction Period Interest Costs Variance Account ("CPICVA");
- Deferred Contingency Deferral Account ("DCDA");
- COVID Construction Costs Deferral Account ("CCCDA");
- 2021-2023 COVID Construction Costs Deferral Account ("2021-2023 CCCDA");
- Construction Period OM&A Variance Account; and
- CWIP Account 2055.

In summary, WPLP is seeking partial disposition for six of its accounts in the 2024 test year. Table 1, below, sets out the amounts proposed for disposition from the following five accounts: the Pikangikum Distribution System Deferral Account, the ISDVA, the CPICVA, the DCDA and the CCCDA. The sixth account for which partial disposition is sought, CWIP Account 2055, is disposed of through rate base (as described in Section A below) and is therefore not listed in the summary table below. Also included in Table 1 is the 2021-2023 CCCDA, for which WPLP is seeking to transfer amounts to CWIP Account 2055. Each of these proposals is described in greater detail below. WPLP is not seeking disposition for the Construction Period OM&A Variance Account as no amounts have been recorded in this account to date.

WPLP is proposing to dispose of the ISDVA, CPICVA and DCDA over a 4-year period to mitigate ratepayer and WPLP financial impacts. While there is an overall balance owed to ratepayers from these accounts in 2024, WPLP is forecasting a balance due from ratepayers in the CPICVA in excess of $20 million for the 2025 test year. As such, establishing a 4-year recovery period for these accounts is equitable to both WPLP and Ontario ratepayers. WPLP's proposed disposition periods for its other accounts are consistent with the disposition periods used in its 2023 rate application.

Table 1 – Deferral Account Disposition Continuity

	Audited 2021 Balance[1]	2022 Incremental Costs	2022 Transfers	2022 Recovery	Audited 2022 Balance[2]	Forecasted Carrying Charges	2023 Application Recovery	Adjusted Balance	Disposition to LTPL[3]	Disposition to RCL[3]
Pikangikum Distribution System Deferral Account	$3,243,928	$1,740,763	-	($2,046,966)	$2,937,725	158,973	($1,193,963)	$1,899,735	-	$1,899,735
In-Service Date Variance Account	-	($15,195,242)	-	-	($15,195,242)	(2,264,673)	-	($17,459,915)	($1,763,962)	($2,601,017)
Construction Period Interest Costs Variance Account	-	$3,395,782	-	-	$3,395,782	510,469	-	$3,906,251	$551,307	$425,256
Deferred Contingency Deferral Account	-	$22,082	-	-	$22,082	3,319	-	$25,400	$5,747	$603
COVID Construction Costs Deferral Account	$59,496,634	$392,288	($42,096,982)	($4,349,913)	$13,442,027	993,801	($4,349,913)	$10,085,915	$3,516,436[4]	$1,526,521[4]
COVID Construction Costs 2021-2023 Deferral Account	-	$27,086,848	$42,096,982	-	$69,183,830	-	-	$69,183,830	-	-
	$62,740,562	$43,293,945	-	($6,396,879)	$73,786,203	(598,111)	($5,543,876)	$67,641,216	$2,309,529	$1,251,098

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[1] Exhibit A-7-1- Attachment 2. Note that COVID-19 costs were recorded in CWIP Account 2055 in the 2020 audited financial statements and reclassed to a deferral account in 2021 upon OEB approval of the CCCDA in EB-2021-0134.

[2] Audited balances include deferral account carrying charges.

[3] Disposition amount is 25% of adjusted deferral account balance for the ISDVA, DPICVA and DCDA.

[4] Disposition amount is 25% of deferral account balance as at December 31, 2020 approved in EB-2021-0134 plus carrying charges.

A. Pikangikum Distribution System Deferral Account

As noted in Exhibit H-1-1, the Pikangikum Distribution System was converted to being supplied by HONI’s 115 kV transmission system on May 12, 2023, and effective from that date has formed part of WPLP’s Transmission System. In the current Application, WPLP proposes to dispose of the incremental portion of the audited December 31, 2022 balance for this account, inclusive of forecasted interest to the end of 2023.

Specifically, WPLP proposes to dispose of $1,899,735, being the incremental portion of the audited December 31, 2022 balance inclusive of incurred carrying charges ($1,740,762**)**, plus forecasted interest to the end of 2023 of $158,973, by adding these amounts to the portion of its 2024 base transmission revenue requirement that is allocated to the Remote Connection Lines.

While no new capital or OM&A costs will be recorded in the account during 2024, WPLP proposes to continue this account until the final balance has been disposed of in a future transmission revenue requirement application to the OEB. As WPLP has incurred costs in respect of the Pikangikum Distribution System up to the date of conversion on May 12, 2023, the final audited balance is not expected to be disposed of until WPLP’s 2025 transmission rate application.

Adding the amounts being disposed of to the portion of the base revenue requirement that is allocated to the Remote Connection Lines will result in cost recovery through the fixed monthly charge that is applicable to HORCI. This is appropriate since HORCI is the distributor providing service to the Pikangikum First Nation, which is the only load that was served by WPLP’s Pikangikum Distribution System. HORCI is therefore the entity that would have otherwise paid these costs if WPLP had established distribution rates instead of this deferral account.

B. In-Service Date Variance Account (ISDVA)

WPLP proposes to dispose of the audited December 31, 2022 balance plus forecasted interest for 2023 in this account, and to continue using this account in 2024 to record the differences between its approved revenue requirement based on the forecasted in-service dates for the relevant lines/stations and its revenue requirement if calculated based on the actual in-service dates for those lines/stations. WPLP is proposing disposition of the balance in the ISDVA over a 4-year period.

C. Construction Period Interest Costs Variance Account (CPICVA)

WPLP proposes to dispose of the audited December 31, 2022 balance plus forecasted interest for 2023 in this account, and to continue using this account in 2024 to record the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in the 2023 rate application and WPLP's actual effective interest rate on long-term debt during the construction period. WPLP is proposing disposition of the balance over a 4-year period.

D. Deferred Contingency Deferral Account (DCDA)

WPLP proposes to dispose of the audited December 31, 2022 balance plus forecasted interest for 2023 in this account, and to continue using this account in 2024. WPLP will continue to use the DCDA in 2024 to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP will seek to recover, to the extent the forecasted contingency is actually realized, limited to the revenue requirement impact attributable to contingency costs for 2023 and 2024 to a maximum of $81,881,849. WPLP is proposing disposition of the balance over a 4-year period**.**

E. COVID Construction Costs Deferral Account (CCCDA)

Pursuant to the approved Settlement Agreement in EB-2021-0134 and as confirmed in the approved Settlement Agreement in EB-2022-0149, WPLP will recover its audited 2020 year-end balance over a four-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025) plus carrying charges for 2021, 2022 and 2023 in 2024. Accordingly, in 2024 WPLP seeks recovery of $5,042,957, which represents the third 25% tranche of the total audited 2020 year-end balance ($4,349,913), plus applicable carrying costs of $693,044.

F. 2021-2023 COVID Construction Costs Deferral Account (CCCDA)

WPLP is proposing to transfer the 2021-2023 CCCDA audited (to December 31, 2022, in the amount of $69,183,830), and unaudited (from January 1, 2023 to December 31, 2023, in the amount of $11,022,005) 2023 year-end forecast balance to CWIP Account 2055 on December 31, 2023, inclusive of carrying charges. As discussed in Exhibit H-1-1, WPLP is proposing to expand the scope of this account by one year to include 2020 and to continue the 2021-2023 CCCDA to enable tracking of any COVID-related capital costs that it may recognize as having been incurred by WPLP upon conclusion of the commercial discussions that are ongoing with its EPC contractor and which may relate to the 2020-2023 period. See also the discussion of CWIP Account 2055 below and Exhibit H-2-2.

G. CWIP Account 2055

As described in Exhibit H-1-1, WPLP was directed by the OEB in the LTC Decision to record its transmission system construction costs in CWIP Account 2055. In addition, in the LTC Decision the OEB directed WPLP to transfer the balances from its Transmission Development Costs Deferral Account to CWIP Account 2055. The transferred development costs are recorded in sub-accounts related to capital costs and carrying charges. WPLP proposes to recover these amounts as follows:

- The balances in the CWIP Account 2055 sub-accounts for development capital costs and associated carrying charges[5], previously included in the Transmission Development Costs Deferral Account, are proposed to be recovered through the allocation of all indirect capital costs (which include these development costs) to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in Exhibit C-2-1.[6] The reasonableness of WPLP's transmission development costs is supported by evidence provided throughout this application, particularly in Exhibit B.

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[5] In accordance with the approved Settlement Agreement in EB-2021-0134, the third-party funding sub-account has been discontinued.

[6] WPLP's development costs are part of the Non-EPC Capital Costs described in Exhibits B-1-5 and C-1-2. For clarity, the Non-EPC Capital Costs that are allocated proportionally to fixed assets as they come into service include both historical actual development costs described in this bullet, plus the historical and forecasted capital construction costs described in the next bullet.

- The balances in the CWIP Account 2055 consisting of construction costs for the transmission project are proposed to be recovered through the assignment of these direct capital costs to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in Exhibit C-2-1. The reasonableness of WPLP's transmission construction costs is supported by evidence provided throughout this application, particularly in Exhibit B.

Regarding the COVID-related costs for which WPLP has requested to transfer amounts to CWIP Account 2055 from the 2021-2023 CCCDA, WPLP proposes as follows:

- In respect of assets that are in service as of the date of this Application or that are expected to come into service during the remainder of 2023, WPLP proposes to add to its rate base, effective January 1, 2024[7], the COVID-related costs;

- In respect of assets that are expected to come into service during 2024, WPLP proposes to add to its rate base, effective from the dates such assets come into service during 2024, the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023; and

- In respect of all such COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055, WPLP proposes to treat them as part of the construction costs for the transmission project. As such, WPLP proposes to assign direct costs and allocate indirect costs to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in Exhibit C-2-1. The reasonableness of these COVID-related costs is supported by evidence set out in Exhibit H-2-2.

WPLP has included Attachment A which provides the continuities for each account and the forecasted carry charges for recovery.

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[7] More detail provided in Exhibit C-2-1 Table 1.

Exhibit H, Tab 2, Schedule 1

Disposition of Deferral and Variance Accounts

ATTACHMENT 1

Continuity Tables for Deferral and Variance Account Recovery

Wataynikaneyap Power LP
Interest Schedule
2024 Rate Application Support

Construction Periond Interest Cost Variance	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**
Opening Principle Balance	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	- 70,483
Closing Principle Balance	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,383,187	3,312,704
OEB Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	12,595	26,186	38,462	52,053	65,901	80,211	94,058	108,368	122,677	136,525	150,835	164,683	178,992
Interest Addition	13,591	12,276	13,591	13,848	14,309	13,848	14,309	14,309	13,848	14,309	13,848	14,309	14,309
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	- 10,897
Closing Interest Balance	26,186	38,462	52,053	65,901	80,211	94,058	108,368	122,677	136,525	150,835	164,683	178,992	182,404

2022 Audited Balance	
Principle	3,383,187
Interest	12,595
	3,395,782
Per FS	3,395,782
Variance	-

Deferred Contingency Deferral Account	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**
Opening Principle Balance	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	- 458
Closing Principle Balance	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,994	21,536
OEB Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	87	176	256	344	434	527	617	710	803	893	986	1,076	1,169
Interest Addition	88	80	88	90	93	90	93	93	90	93	90	93	93
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	- 71
Closing Interest Balance	176	256	344	434	527	617	710	803	893	986	1,076	1,169	1,191

2022 Audited Balance	
Principle	21,994
Interest	87
	22,082
Per FS	22,082
Variance	-

COVID Construction Cost Deferral Account - 2020	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**
Opening Principle Balance	13,049,739	12,687,246	12,324,754	11,962,261	11,599,768	11,237,275	10,874,783	10,512,290	10,149,797	9,787,304	9,424,812	9,062,319	8,699,826
Principle Recovery	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493
Closing Principle Balance	12,687,246	12,324,754	11,962,261	11,599,768	11,237,275	10,874,783	10,512,290	10,149,797	9,787,304	9,424,812	9,062,319	8,699,826	8,337,333
OEB Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	392,288	444,712	490,748	540,259	589,223	638,285	684,281	730,277	774,739	816,284	857,680	896,257	934,587
Interest Addition	52,424	46,036	49,512	48,963	49,062	45,996	45,996	44,463	41,545	41,396	38,577	38,330	36,797
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	- 57,754
Closing Interest Balance	444,712	490,748	540,259	589,223	638,285	684,281	730,277	774,739	816,284	857,680	896,257	934,587	913,630

2022 Audited Balance	
Principle	13,049,739
Interest	392,288
	13,442,027
Per FS	13,442,027
Variance	-

Wataynikaneyap Power LP
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Construction Periond Interest Cost Variance	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**
Opening Principle Balance	3,312,704	3,242,221	3,171,738	3,101,255	3,030,772	2,960,289	2,889,806	2,819,323	2,748,839	2,678,356	2,607,873	2,537,390	2,466,907
Principle Recovery	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483
Closing Principle Balance	3,242,221	3,171,738	3,101,255	3,030,772	2,960,289	2,889,806	2,819,323	2,748,839	2,678,356	2,607,873	2,537,390	2,466,907	2,396,424
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	29	31	30	31	30	31	31	30	31	30	31	31	28
Opening Interest Balance	182,404	184,615	187,431	189,516	191,736	193,244	194,868	196,193	196,836	197,565	197,631	197,764	197,599
Interest Addition	13,107	13,713	12,982	13,117	12,405	12,521	12,223	11,540	11,626	10,963	11,030	10,732	9,424
Interest Recovery	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897
Closing Interest Balance	184,615	187,431	189,516	191,736	193,244	194,868	196,193	196,836	197,565	197,631	197,764	197,599	196,126
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Deferred Contingency Deferral Account	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**
Opening Principle Balance	21,536	21,078	20,620	20,161	19,703	19,245	18,787	18,328	17,870	17,412	16,954	16,496	16,037
Principle Recovery	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458
Closing Principle Balance	21,078	20,620	20,161	19,703	19,245	18,787	18,328	17,870	17,412	16,954	16,496	16,037	15,579
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	29	31	30	31	30	31	31	30	31	30	31	31	28
Opening Interest Balance	1,191	1,205	1,224	1,237	1,251	1,261	1,272	1,280	1,284	1,289	1,289	1,290	1,289
Interest Addition	85	89	84	85	81	81	79	75	76	71	72	70	61
Interest Recovery	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71
Closing Interest Balance	1,205	1,224	1,237	1,251	1,261	1,272	1,280	1,284	1,289	1,289	1,290	1,289	1,279
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

COVID Construction Cost Deferral Account - 2020	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**
Opening Principle Balance	8,337,333	7,974,841	7,612,348	7,249,855	6,887,362	6,524,870	6,162,377	5,799,884	5,437,391	5,074,899	4,712,406	4,349,913	3,987,420
Principle Recovery	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493
Closing Principle Balance	7,974,841	7,612,348	7,249,855	6,887,362	6,524,870	6,162,377	5,799,884	5,437,391	5,074,899	4,712,406	4,349,913	3,987,420	3,624,928
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	29	31	30	31	30	31	31	30	31	30	31	31	28
Opening Interest Balance	913,630	888,865	864,842	838,246	811,157	781,594	751,438	719,748	685,734	650,979	613,997	576,175	536,820
Interest Addition	32,988	33,730	31,158	30,664	28,191	27,598	26,064	23,740	22,998	20,772	19,932	18,398	15,233
Interest Recovery	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754
Closing Interest Balance	888,865	864,842	838,246	811,157	781,594	751,438	719,748	685,734	650,979	613,997	576,175	536,820	494,299
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

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Construction Periond Interest Cost Variance	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
Opening Principle Balance	2,396,424	2,325,941	2,255,458	2,184,975	2,114,492	2,044,009	1,973,526	1,903,043	1,832,560	1,762,077	1,691,594	1,621,110	1,550,627
Principle Recovery	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483
Closing Principle Balance	2,325,941	2,255,458	2,184,975	2,114,492	2,044,009	1,973,526	1,903,043	1,832,560	1,762,077	1,691,594	1,621,110	1,550,627	1,480,144
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	30	31	31	30	31	30	31	31	28	31
Opening Interest Balance	196,126	195,365	193,988	192,631	190,677	188,723	186,471	183,652	180,804	177,408	173,963	170,221	165,517
Interest Addition	10,136	9,520	9,540	8,943	8,943	8,645	8,078	8,049	7,501	7,453	7,155	6,193	6,559
Interest Recovery	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897
Closing Interest Balance	195,365	193,988	192,631	190,677	188,723	186,471	183,652	180,804	177,408	173,963	170,221	165,517	161,178

2022 Audited Balance
Principle
Interest

Per FS
Variance

Deferred Contingency Deferral Account	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
Opening Principle Balance	15,579	15,121	14,663	14,205	13,746	13,288	12,830	12,372	11,913	11,455	10,997	10,539	10,081
Principle Recovery	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458
Closing Principle Balance	15,121	14,663	14,205	13,746	13,288	12,830	12,372	11,913	11,455	10,997	10,539	10,081	9,622
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	30	31	31	30	31	30	31	31	28	31
Opening Interest Balance	1,279	1,274	1,265	1,256	1,243	1,230	1,215	1,197	1,178	1,156	1,134	1,109	1,079
Interest Addition	66	62	62	58	58	56	53	52	49	48	47	40	43
Interest Recovery	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71
Closing Interest Balance	1,274	1,265	1,256	1,243	1,230	1,215	1,197	1,178	1,156	1,134	1,109	1,079	1,050

2022 Audited Balance
Principle
Interest

Per FS
Variance

COVID Construction Cost Deferral Account - 2020	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
Opening Principle Balance	3,624,928	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,986	362,493	-	-	-
Principle Recovery	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	-	-	-
Closing Principle Balance	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,986	362,493	-	-	-	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	30	31	31	30	31	30	31	31	28	31
Opening Interest Balance	494,299	451,877	407,477	361,989	314,622	266,067	215,980	164,161	111,007	56,220	-	-	-
Interest Addition	15,332	13,354	12,266	10,386	9,199	7,666	5,935	4,600	2,967	1,533			
Interest Recovery	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	- 57,754	-	-	-
Closing Interest Balance	451,877	407,477	361,989	314,622	266,067	215,980	164,161	111,007	56,220	-	-	-	-

2022 Audited Balance
Principle
Interest

Per FS
Variance

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Construction Periond Interest Cost Variance	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**
Opening Principle Balance	1,480,144	1,409,661	1,339,178	1,268,695	1,198,212	1,127,729	1,057,246	986,763	916,280	845,797	775,314	704,831	634,348
Principle Recovery	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483
Closing Principle Balance	1,409,661	1,339,178	1,268,695	1,198,212	1,127,729	1,057,246	986,763	916,280	845,797	775,314	704,831	634,348	563,865
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	30	31	30	31	31	30	31	30	31	31	28	31	30
Opening Interest Balance	161,178	156,340	151,405	145,989	140,458	134,629	128,347	121,922	115,064	108,042	100,722	92,787	84,871
Interest Addition	6,058	5,962	5,481	5,366	5,068	4,616	4,472	4,039	3,875	3,577	2,962	2,981	2,596
Interest Recovery	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897
Closing Interest Balance	156,340	151,405	145,989	140,458	134,629	128,347	121,922	115,064	108,042	100,722	92,787	84,871	76,570
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Deferred Contingency Deferral Account	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**
Opening Principle Balance	9,622	9,164	8,706	8,248	7,790	7,331	6,873	6,415	5,957	5,499	5,040	4,582	4,124
Principle Recovery	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458
Closing Principle Balance	9,164	8,706	8,248	7,790	7,331	6,873	6,415	5,957	5,499	5,040	4,582	4,124	3,666
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	30	31	30	31	31	30	31	30	31	31	28	31	30
Opening Interest Balance	1,050	1,019	986	951	915	877	836	794	750	704	656	604	553
Interest Addition	39	39	36	35	33	30	29	26	25	23	19	19	17
Interest Recovery	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71
Closing Interest Balance	1,019	986	951	915	877	836	794	750	704	656	604	553	499
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

COVID Construction Cost Deferral Account - 2020	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**
Opening Principle Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Principle Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	30	31	30	31	31	30	31	30	31	31	28	31	30
Opening Interest Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Addition													
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Wataynikaneyap Power LP
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Construction Periond Interest Cost Variance	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Opening Principle Balance	563,865	493,381	422,898	352,415	281,932	211,449	140,966	70,483
Principle Recovery	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483	- 70,483
Closing Principle Balance	493,381	422,898	352,415	281,932	211,449	140,966	70,483	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	31	30	31	30	31
Opening Interest Balance	76,570	68,058	59,180	50,072	40,665	30,922	20,919	10,599
Interest Addition	2,385	2,019	1,789	1,491	1,154	894	577	298
Interest Recovery	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897	- 10,897
Closing Interest Balance	68,058	59,180	50,072	40,665	30,922	20,919	10,599	-
2022 Audited Balance								
Principle								
Interest								
Per FS								
Variance								

Deferred Contingency Deferral Account	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Opening Principle Balance	3,666	3,207	2,749	2,291	1,833	1,375	916	458
Principle Recovery	- 458	- 458	- 458	- 458	- 458	- 458	- 458	- 458
Closing Principle Balance	3,207	2,749	2,291	1,833	1,375	916	458	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	31	30	31	30	31
Opening Interest Balance	499	443	385	326	265	201	136	69
Interest Addition	16	13	12	10	8	6	4	2
Interest Recovery	- 71	- 71	- 71	- 71	- 71	- 71	- 71	- 71
Closing Interest Balance	443	385	326	265	201	136	69	-
2022 Audited Balance								
Principle								
Interest								
Per FS								
Variance								

COVID Construction Cost Deferral Account - 2020	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Opening Principle Balance	-	-	-	-	-	-	-	-
Principle Recovery	-	-	-	-	-	-	-	-
Closing Principle Balance	-	-	-	-	-	-	-	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	31	30	31	30	31
Opening Interest Balance	-	-	-	-	-	-	-	-
Interest Addition								
Interest Recovery	-	-	-	-	-	-	-	-
Closing Interest Balance	-	-	-	-	-	-	-	-
2022 Audited Balance								
Principle								
Interest								
Per FS								
Variance								

In-Service Date Variance Account	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**
Opening Principle Balance	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	312,695
Closing Principle Balance	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 15,009,351	- 14,696,656
OEB Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	- 185,891	- 246,188	- 300,649	- 360,945	- 422,381	- 485,864	- 547,300	- 610,783	- 674,267	- 735,702	- 799,185	- 860,621	- 924,104
Interest Addition	- 60,296	- 54,461	- 60,296	- 61,436	- 63,483	- 61,436	- 63,483	- 63,483	- 61,436	- 63,483	- 61,436	- 63,483	- 63,483
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	51,053
Closing Interest Balance	- 246,188	- 300,649	- 360,945	- 422,381	- 485,864	- 547,300	- 610,783	- 674,267	- 735,702	- 799,185	- 860,621	- 924,104	- 936,534
2022 Audited Balance													
Principle	- 15,009,351												
Interest	- 185,891												
	- 15,195,242												
Per FS	- 15,195,242												
Variance	-												

Distribution System Deferral Account	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**
Opening Principle Balance	2,861,436	2,762,855	2,664,275	2,565,695	2,467,115	2,368,535	2,269,955	2,171,375	2,072,794	1,974,214	1,875,634	1,777,054	1,678,474
Principle Recovery	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 98,580	- 139,873
Closing Principle Balance	2,762,855	2,664,275	2,565,695	2,467,115	2,368,535	2,269,955	2,171,375	2,072,794	1,974,214	1,875,634	1,777,054	1,678,474	1,538,601
OEB Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	76,289	86,617	95,475	105,012	114,347	123,615	132,143	140,577	148,594	155,912	163,095	169,606	175,955
Interest Addition	11,495	10,025	10,703	10,502	10,435	9,695	9,601	9,184	8,484	8,350	7,677	7,516	7,099
Interest Recovery	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 1,167	- 18,438
Closing Interest Balance	86,617	95,475	105,012	114,347	123,615	132,143	140,577	148,594	155,912	163,095	169,606	175,955	164,616
2022 Audited Balance													
Principle	2,861,436												
Interest	76,289												
	2,937,724												
Per FS	2,937,724												
Variance	-												

In-Service Date Variance Account	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25
Opening Principle Balance	- 14,696,656	- 14,383,961	- 14,071,266	- 13,758,571	- 13,445,877	- 13,133,182	- 12,820,487	- 12,507,792	- 12,195,097	- 11,882,402	- 11,569,708	- 11,257,013	- 10,944,318
Principle Recovery	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695
Closing Principle Balance	- 14,383,961	- 14,071,266	- 13,758,571	- 13,445,877	- 13,133,182	- 12,820,487	- 12,507,792	- 12,195,097	- 11,882,402	- 11,569,708	- 11,257,013	- 10,944,318	- 10,631,623
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	29	31	30	31	30	31	31	30	31	30	31	31	28
Opening Interest Balance	- 936,534	- 943,631	- 953,416	- 959,959	- 967,098	- 971,081	- 975,575	- 978,747	- 978,890	- 979,417	- 977,000	- 974,882	- 971,441
Interest Addition	- 58,150	- 60,838	- 57,596	- 58,193	- 55,036	- 55,548	- 54,225	- 51,196	- 51,580	- 48,636	- 48,935	- 47,613	- 41,810
Interest Recovery	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053
Closing Interest Balance	- 943,631	- 953,416	- 959,959	- 967,098	- 971,081	- 975,575	- 978,747	- 978,890	- 979,417	- 977,000	- 974,882	- 971,441	- 962,198
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Distribution System Deferral Account	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25
Opening Principle Balance	1,538,601	1,398,728	1,258,855	1,118,983	979,110	839,237	699,364	559,491	419,618	279,746	139,873	0	0
Principle Recovery	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	- 139,873	-	-
Closing Principle Balance	1,398,728	1,258,855	1,118,983	979,110	839,237	699,364	559,491	419,618	279,746	139,873	0	0	0
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	29	31	30	31	30	31	31	30	31	30	31	31	28
Opening Interest Balance	164,616	152,265	139,743	126,457	112,752	98,321	83,432	67,952	51,804	35,140	17,847	- 0	- 0
Interest Addition	6,088	5,916	5,153	4,733	4,008	3,550	2,958	2,290	1,775	1,145	592	0	0
Interest Recovery	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	- 18,438	-	-
Closing Interest Balance	152,265	139,743	126,457	112,752	98,321	83,432	67,952	51,804	35,140	17,847	- 0	- 0	- 0
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

In-Service Date Variance Account	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
Opening Principle Balance	- 10,631,623	- 10,318,928	- 10,006,234	- 9,693,539	- 9,380,844	- 9,068,149	- 8,755,454	- 8,442,760	- 8,130,065	- 7,817,370	- 7,504,675	- 7,191,980	- 6,879,286
Principle Recovery	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695
Closing Principle Balance	- 10,318,928	- 10,006,234	- 9,693,539	- 9,380,844	- 9,068,149	- 8,755,454	- 8,442,760	- 8,130,065	- 7,817,370	- 7,504,675	- 7,191,980	- 6,879,286	- 6,566,591
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	30	31	31	30	31	30	31	31	28	31
Opening Interest Balance	- 962,198	- 956,112	- 947,295	- 938,564	- 927,188	- 915,812	- 903,113	- 887,897	- 872,553	- 854,777	- 836,788	- 817,476	- 793,898
Interest Addition	- 44,967	- 42,237	- 42,322	- 39,677	- 39,677	- 38,355	- 35,837	- 35,709	- 33,278	- 33,064	- 31,742	- 27,475	- 29,097
Interest Recovery	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053
Closing Interest Balance	- 956,112	- 947,295	- 938,564	- 927,188	- 915,812	- 903,113	- 887,897	- 872,553	- 854,777	- 836,788	- 817,476	- 793,898	- 771,941
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Distribution System Deferral Account	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
Opening Principle Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Principle Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	30	31	31	30	31	30	31	31	28	31
Opening Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0
Interest Addition	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

In-Service Date Variance Account	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**
Opening Principle Balance	- 6,566,591	- 6,253,896	- 5,941,201	- 5,628,506	- 5,315,812	- 5,003,117	- 4,690,422	- 4,377,727	- 4,065,032	- 3,752,338	- 3,439,643	- 3,126,948	- 2,814,253
Principle Recovery	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695
Closing Principle Balance	- 6,253,896	- 5,941,201	- 5,628,506	- 5,315,812	- 5,003,117	- 4,690,422	- 4,377,727	- 4,065,032	- 3,752,338	- 3,439,643	- 3,126,948	- 2,814,253	- 2,501,558
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	30	31	30	31	31	30	31	30	31	31	28	31	30
Opening Interest Balance	- 771,941	- 747,766	- 723,164	- 696,428	- 669,181	- 640,612	- 610,037	- 578,822	- 545,687	- 511,827	- 476,644	- 438,731	- 400,904
Interest Addition	- 26,878	- 26,451	- 24,318	- 23,806	- 22,484	- 20,479	- 19,839	- 17,919	- 17,193	- 15,871	- 13,140	- 13,226	- 11,519
Interest Recovery	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053
Closing Interest Balance	- 747,766	- 723,164	- 696,428	- 669,181	- 640,612	- 610,037	- 578,822	- 545,687	- 511,827	- 476,644	- 438,731	- 400,904	- 361,369
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

Distribution System Deferral Account	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**
Opening Principle Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Principle Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	30	31	30	31	31	30	31	30	31	31	28	31	30
Opening Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0
Interest Addition	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0
2022 Audited Balance													
Principle													
Interest													
Per FS													
Variance													

In-Service Date Variance Account	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Opening Principle Balance	- 2,501,558	- 2,188,864	- 1,876,169	- 1,563,474	- 1,250,779	- 938,084	- 625,390	- 312,695
Principle Recovery	312,695	312,695	312,695	312,695	312,695	312,695	312,695	312,695
Closing Principle Balance	- 2,188,864	- 1,876,169	- 1,563,474	- 1,250,779	- 938,084	- 625,390	- 312,695	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	31	30	31	30	31
Opening Interest Balance	- 361,369	- 320,897	- 278,803	- 235,685	- 191,244	- 145,310	- 98,224	- 49,731
Interest Addition	- 10,581	- 8,959	- 7,935	- 6,613	- 5,120	- 3,968	- 2,560	- 1,323
Interest Recovery	51,053	51,053	51,053	51,053	51,053	51,053	51,053	51,053
Closing Interest Balance	- 320,897	- 278,803	- 235,685	- 191,244	- 145,310	- 98,224	- 49,731	-
2022 Audited Balance								
Principle								
Interest								
Per FS								
Variance								

Distribution System Deferral Account	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Opening Principle Balance	0	0	0	0	0	0	0	0
Principle Recovery	-	-	-	-	-	-	-	-
Closing Principle Balance	0	0	0	0	0	0	0	-
OEB Interest Rate	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
# of days in month	31	30	31	31	30	31	30	31
Opening Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	- 0
Interest Addition	0	0	0	0	0	0	0	0
Interest Recovery	-	-	-	-	-	-	-	-
Closing Interest Balance	- 0	- 0	- 0	- 0	- 0	- 0	- 0	-
2022 Audited Balance								
Principle								
Interest								
Per FS								
Variance								

Exhibit H, Tab 2, Schedule 2

COVID - Related Construction Costs

COVID-RELATED CONSTRUCTION COSTS

This schedule provides an overview of the OEB-approved and WPLP-proposed treatments for construction costs resulting from the COVID-19 pandemic and related matters.

A. BACKGROUND

The COVID-19 pandemic has impacted the Transmission Project's cost, including costs related to WPLP's EPC contract as well as costs unrelated to its EPC contract. Some of the impacts have been described in WPLP's previous transmission rate applications.[1] Since its last rate application, WPLP has continued to diligently monitor and oversee the performance of its EPC contractor, Valard, including with respect to health and safety, implementation of the COVID-19 Management Plan, schedule and cost.

WPLP is forecasting that, by the end of 2023, it will have incurred known COVID-19 Transmission Project costs unrelated to its EPC contract of approximately $1.4 million, and under its EPC contract of approximately $92 million. The amounts incurred under the EPC contract were approximately $17.4 million in 2020, $68.2 million in 2021-2022 and are forecast to be approximately $6.4 million by the end of 2023. Notably, there are additional COVID-19 costs not included in these amounts that are the subject of commercial discussions currently progressing between WPLP and its EPC contractor in relation to EPC costs and schedule. As these additional costs are the subject of ongoing commercial discussions between the parties, they remain uncertain.[2] While these additional costs may relate to the period since the onset of the pandemic in early 2020, due to their remaining uncertainty they have not been recognized by WPLP as having been incurred given the status of the commercial discussions to date.

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[1] See Exhibit H-2-2 in each of EB-2021-0134 and EB-2022-0149.

[redacted]

B. PREVIOUSLY APPROVED RATE TREATMENT

Through WPLP's prior transmission rate proceedings, the OEB has provided for the recovery of known 2020 costs from the COVID-19 pandemic and for the recording of known 2021-2023 costs from the COVID-19 pandemic in deferral accounts, as follows.

1. 2020 COVID-19 Costs

In EB-2021-0134, the OEB approved a Settlement Proposal pursuant to which the parties agreed that WPLP will (a) establish a new COVID Construction Costs Deferral Account (CCCDA), effective March 11, 2020, to record the amount of construction costs relating to the Transmission System that are directly attributable to the COVID-19 pandemic, and (b) recover the audited year-end 2020 balance thereof, together with applicable carrying costs, as an expense through disposition over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025). WPLP incurred total known COVID-19 costs of approximately $17.4 million in 2020 and will continue to recover the applicable portions of this amount, plus carrying costs, in 2024 and 2025 in accordance with the OEB's Decision and Order in EB-2021-0134. The specific amount to be recovered in 2024 is identified in Exhibit H-2-1.

The cost of $17.4 million for 2020 reflects the known impacts of implementing COVID-19 health and safety measures, lost productivity in performing construction work and impacts on construction activities during 2020. This cost was incurred by WPLP through the execution of Change Orders under the EPC contract, arising from the COVID-related Force Majeure event, which provided Valard with specific cost and schedule relief, including for 2020. It is important to note that, to the extent Valard claims any additional costs for COVID-19 impacts and related matters (which continue to be the subject of commercial discussions between the parties) related to 2020, such amounts have not been recognized as having been incurred by WPLP to date. For the reasons set out below, any 2020 capital cost amounts, if and when they are recognized as having been incurred by WPLP, would instead be recorded in the 2021–2023 COVID Construction Costs

Deferral Account (2021-2023 CCCDA) at that time, treated as capital, and subject to OEB review upon WPLP requesting disposition of that account.[3]

2. 2021-2023 COVID-19 Costs

In EB-2022-0149, the OEB approved a Settlement Proposal pursuant to which the parties agreed that WPLP will establish the 2021-2023 CCCDA, effective January 1, 2021, to record the year-end construction costs from 2021 to 2023 which are directly attributable to the COVID-19 pandemic, with prudence and the approach to disposition (i.e. as capital or as an expense) to be determined at the time of disposition in a future rate proceeding once the COVID-19 costs for these years are known, and with the applicable carrying charges to be consistent with the approach to disposition that is ultimately approved at the time of disposition (i.e. the CWIP rate/AFUDC if disposed of as capital and the OEB prescribed rate if disposed of as an expense).

WPLP's audited year-end known construction costs directly attributable to the COVID-19 pandemic, as recorded in the 2021-2023 CCCDA, are approximately $42.1 million for 2021 and $26.27 million for 2022. WPLP's unaudited forecast of 2023 known construction costs directly attributable to the COVID-19 pandemic is approximately $6.4 million. WPLP therefore expects that its 2023 year-end balance in the 2021-2023 CCCDA will be approximately $74.6 million[4]. Similar to above it is important to note that, pending the resolution of final EPC costs with Valard, additional costs for COVID-19 impacts and related matters (which continue to be the subject of commercial discussions between the parties) related to the 2021-2023 period, have not been recognized as having been incurred by WPLP to date and are not recorded in the 2021-2023 CCCDA. Any such amounts, if and when they are recognized as having been incurred by WPLP, would instead be recorded in the 2021-2023 CCCDA at that time and would thereafter be subject to OEB review upon WPLP requesting disposition of that account. Any cost for COVID-19 and related matters arising from the resolution of final EPC costs with Valard and related to 2024 or

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[3] See below and Exhibit H-1-1 for WPLP's request to expand the scope of this account to include 2020.

[4] For additional information on COVID-19 cost breakdown see Exhibit B-1-5.

later, and not otherwise related to the 2021- 2023 period (or 2020), would be recorded in the proposed EPC COVID-Related Costs Deferral Account.[5]

[redacted]

As noted above, with respect to the amounts recorded in the 2021-2023 CCCDA, prudence and the approach to disposition (i.e. as capital or as an expense) is to be determined at the time of disposition, and the applicable carrying charges are to be consistent with the approach to disposition that is ultimately approved (i.e. the CWIP rate/AFUDC if disposed of as capital and the OEB prescribed rate if disposed of as an expense). Although WPLP has used the OEB prescribed rate for deferral and variance accounts as the carrying charge on an interim basis, as discussed below WPLP is proposing to treat the recorded amounts as capital. As such, WPLP proposes to update the applicable carrying charges to instead reflect its CWIP rate/AFUDC.

C. PROPOSED RATE TREATMENT

The following sections describe WPLP's proposed rate treatment for its recognized or potential Transmission Project costs arising from the COVID-19 pandemic and related matters.

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[5] See Exhibit H-1-1 and section C.3, below.

1. 2020 COVID-19 Costs

In this Application, in accordance with the OEB's determination in EB-2021-0134, WPLP is continuing to recover the audited year-end 2020 balance of the CCCDA, together with applicable carrying costs, as an expense through disposition over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025). Accordingly, as indicated in Exhibit H-2-1, WPLP is seeking recovery of $5,042,957 in 2024, which represents the third 25% tranche of the total audited 2020 year-end balance, plus applicable carrying costs.

Moreover, as noted above, if and to the extent WPLP recognizes any additional amounts relating to 2020 arising from the resolution of final EPC costs with Valard and recognized for accounting purposes as having been incurred, any such amounts would be recorded in the 2021-2023 CCCDA at the time they are recognized, treated as capital, and subject to OEB review upon WPLP requesting disposition of that account. WPLP considers this to be the appropriate treatment for 2020 capital costs that may arise from the resolution of final EPC COVID-related costs since, as noted below, WPLP is proposing in this Application to dispose of the 2023 year-end balance of the 2021-2023 CCCDA, plus applicable carrying charges, as capital rather than as an expense. In effect, the 2021-2023 CCCDA is a tracking account (inclusive of carrying charges) and not a revenue requirement-based account as in the case of the CCCDA. Any additional COVID-related capital cost for 2020 recognized in the manner described above is more appropriately recorded in an account on the same basis as COVID-related capital costs for 2021- 2023. As a result, WPLP is requesting that the scope of the 2021-2023 CCCDA be expanded to allow for the tracking of 2020 COVID-related capital costs as described above.

2. 2021-2023 COVID-19 Costs

For the known COVID-related costs of approximately $68.2 million that have been incurred by WPLP for 2021 and 2022, and which are currently included in the audited year-end balance of the 2021-2023 CCCDA as at December 31, 2022, WPLP proposes to dispose of this amount as capital, along with applicable carrying charges relating to the period from January 1, 2021 to December 31, 2023, for recovery starting January 1, 2024. In accordance with the terms established for the

2021-2023 CCCDA, the applicable carrying charges are to be consistent with the approved method of disposition. As such, by disposing of this amount as capital, WPLP proposes that the applicable carrying charges be determined based on its CWIP rate (i.e. AFUDC) applicable to the period from January 1, 2021 to December 31, 2023. WPLP proposes that the resulting amount of approximately $73.6 million, be transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023.

For the unaudited forecast of known COVID-related costs of approximately $6.4 million that have been or are expected to be incurred by WPLP by year-end 2023, similar to the above WPLP proposes to dispose of this amount as capital, along with applicable carrying charges based on its CWIP rate (i.e. AFUDC) to December 31, 2023, for recovery starting January 1, 2024. WPLP proposes that the resulting amount of approximately $6.6 million, be transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023.

Regarding the aforementioned costs, once transferred from the 2021-2023 CCCDA to CWIP Account 2055, WPLP further proposes in this Application as follows:

- In respect of assets that are in service as of the date of this Application or that are expected to come into service during the remainder of 2023, WPLP proposes to add to its rate base, effective January 1, 2024, the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023;[6]

- In respect of assets that are expected to come into service during 2024, WPLP proposes to add to its rate base, effective from the dates such assets come into service during 2024, the COVID-related costs transferred from the 2021-2023 CCCDA to CWIP Account 2055 on December 31, 2023; and

- In respect of all such COVID-related costs transferred from the 2021-2023 CCCDA, WPLP proposes to treat them as part of the construction costs for the Transmission Project. As

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[6] See Exhibit C-2-1, Table 1.

such, WPLP proposes to assign direct costs and allocate indirect costs to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in Exhibit C-2-1.

As noted above, if and to the extent WPLP recognizes any additional amounts relating to the 2021-2023 period arising from the resolution of final EPC costs with Valard and recognized for accounting purposes as having been incurred, any such amounts would be recorded in the 2021-2023 CCCDA at the time they are recognized and those amounts would be subject to OEB review upon WPLP requesting disposition of that account.

WPLP's rationale for seeking recovery of the foregoing amounts as capital, rather than as an expense, is discussed in section 5, below.

3. 2024 COVID-19 Costs

WPLP anticipates that it may incur additional COVID-related costs associated with the Transmission Project in 2024 (outside of the costs that are the subject of the ongoing commercial discussions with Valard, which would be recorded in the EPC COVID-Related Costs Deferral Account). Any such costs, to the extent they are known, would be treated as capital. In WPLP's next rate application, it would propose to add such costs directly to rate base effective January 1, 2025.

4. Contractor Cost Overruns

As noted above, the final resolution of EPC costs between Valard and WPLP that relate to COVID-19 impacts and related matters not otherwise recorded in the 2021-2023 CCCDA will be recorded in the EPC COVID-Related Costs Deferral Account. These amounts primarily relate to schedule delays that the EPC contractor takes the position arose from implementation of COVID-19 health and safety measures, as well as access issues in the Whitefeather Forest. These additional costs are currently the subject of commercial discussions between WPLP and Valard and therefore remain uncertain in terms of quantum and responsibility. They may relate to any year of the construction period since the pandemic commenced in early 2020. Consequently, no such amounts are recognized as having been incurred by WPLP to date.[7] If and when any of the amounts are recognized as having been incurred by WPLP upon the conclusion of the commercial discussions or upon otherwise being determined, such amounts, including applicable AFUDC, would be recorded in the appropriate account. As these costs may relate to any year of the construction period since the pandemic commenced, those costs related to the 2020-2023 period (including in relation to in-service and rate based amounts for that period) and subject to the amended scope for the account as requested in this Application will be recorded in the 2021-2023 CCCDA and those costs related to 2024 or later will be recorded in the proposed EPC COVID-Related Costs Deferral Account and thereafter be subject to OEB review upon WPLP requesting disposition of such accounts. The proposed EPC COVID-Related Costs Deferral Account is discussed in Exhibit H-1-1.

5. Rationale for Recovery as Capital

As indicated above, WPLP is proposing in this Application to dispose of the 2023 year-end balance of the 2021-2023 CCCDA, plus applicable carrying charges, as capital rather than as an expense. The following explains WPLP's rationale for seeking recovery of these amounts as capital.

In EB-2021-0134, WPLP described the Federal Funding Framework relating to its project. The Federal Funding Framework for the project was finalized on July 3, 2019, based on definitive documents signed by WPLP, Canada and Ontario. At a high level, the Federal Funding Framework specifies that Canada will provide $1.55 billion in funding in relation to the project, which will serve to reduce the resulting ratepayer impact in two ways:

a) a portion of the funding will be applied as a Contribution in Aid of Construction ("CIAC"), thereby reducing WPLP's rate base in respect of the Remote Connection Lines; and

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[redacted].

b) the remainder of the funding will be provided to an independent Trust which will use the funding to help offset the rate impacts of the Remote Connection Lines on RRRP for Ontario ratepayers.

The portion of funding to be provided to WPLP as a CIAC will be determined by WPLP's total project capital costs. The negotiated Federal Funding Framework establishes a sliding scale such that, as WPLP’s costs increase, the CIAC amount increases at a rate that reduces WPLP’s deemed equity position in the project. This provides a strong incentive to control and reduce capital costs during construction. Federally funded CIAC treatment for the Remote Connection Lines results in a reduction to the fixed monthly charges that WPLP recovers from HORCI, which will in turn result in HORCI needing to collect less revenue from the RRRP pool. Funding provided to the independent Trust will further reduce rate impacts for Ontario ratepayers because the independent Trust will be required to provide funds to the IESO to be applied against the total RRRP funding that the IESO needs to collect from Ontario ratepayers each month, until such time as the independent Trust's funds are exhausted.

Based on the current forecasted construction cost, not including any amounts that may ultimately be recorded for recovery in the proposed EPC COVID-Related Costs Deferral Account, the Owner’s equity at the end of construction would be at the floor point on the sliding scale under the Federal Funding Framework. As such, whereas it was to the benefit of ratepayers in the initial rate application for COVID-related costs to be treated as an expense, it is now to the benefit of ratepayers for WPLP to treat COVID-related costs using the more standard approach, as capital.

Exhibit I, Tab 1, Schedule 1

Overview of Cost Allocation & Rate Design

OVERVIEW OF COST ALLOCATION & RATE DESIGN

In contrast to other Ontario transmitters, where cost recovery is predominantly achieved through the three UTR rate pools, WPLP is subject to a unique cost recovery and rate framework, requested and approved by the OEB in EB-2018-0190, as described further in Exhibit I-2-1. Under this framework, WPLP must allocate its revenue requirement between the Line to Pickle Lake (for recovery through the UTR Network rate) and the Remote Connection Lines (for recovery through monthly fixed charges applicable to HORCI).

This exhibit provides details of WPLP's cost allocation process, impacts to the UTR Network rate, the determination of the fixed monthly rate applicable to HORCI, and the bill impacts resulting from WPLP's 2024 revenue requirement.

The components of WPLP's 2024 revenue requirement, with references to supporting schedules in this Application, are summarized in Table 1, below.

Table 1 – Summary of 2024 Revenue Requirement

	Total	**Reference**
Gross Fixed Assets (avg)	1,506,408,792	C-3-1
Accumulated Depreciation (avg)	-33,802,548	C-3-1
Net Fixed Assets (avg)	1,472,606,245	C-1-1
Working Capital Allowance	0	C-4-1
Rate Base	1,472,606,245	C-1-1
Regulated Rate of Return	6.81%	G-2-1
Regulated Return on Rate Base	100,211,706	G-2-1
OM&A Expenses	30,983,687	F-2-1
Property Taxes	0	F-5-1
Depreciation Expense	30,433,091	F-4-1
Income Taxes	501,972	F-5-1
Service Revenue Requirement	**162,130,456**	
Other Revenue Offset	0	E-3-1

Base Revenue Requirement	**162,130,456**	
Disposition of Pikangikum Distribution System Deferral Account	1,899,734	H-2-1
Disposition of COVID Deferral Account (CCCDA)	5,042,957	H-2-1
Disposition of In-Service Date Variance Account	-4,364,979	H-2-1
Disposition of Construction Period Interest Costs Variance Account	976,563	H-2-1
Disposition of Deferred Contingency Deferral Account	6,350	H-2-1
Revenue Requirement for Rates	**165,691,082**	

A. Cost Allocation

WPLP's 2024 Revenue Requirement for Rates of approximately $165.7 million is allocated between the Line to Pickle Lake and the Remote Connection Lines as shown in Table 2.

Table 2 – Allocation of 2024 Revenue Requirement

	LTPL	RCL	Total
Revenue Requirement for Rates	**37,657,460**	**128,033,622**	**165,691,082**

Exhibit I-2-1 provides the details supporting this allocation, along with references to supporting sections of the Application.

B. Rate Design and Bill Impacts

In Exhibit I-3-1, WPLP has calculated a resulting change in the UTR Network rate of $0.03/kW, using status-quo values for all other transmitters in order to isolate the impact of this Application. The bill impact resulting from the Line to Pickle Lake revenue requirement is $0.05 per month, or 0.04% for a typical residential customer, as detailed in Exhibit I-4-1. WPLP anticipates that the OEB will determine actual 2024 UTR rates in a generic proceeding, based on the approved 2024 revenue requirements of each transmitter in Ontario.

In accordance with WPLP's OEB-approved cost recovery and rate framework, the revenue requirement allocated to the Remote Connection Lines will be recovered through a fixed monthly charge of $10,669,468 applicable to HORCI, effective from January 1, 2024, as described in Exhibit I-3-2. The expense incurred by HORCI in respect of this transmission rate would form part of HORCI's revenue requirement and as such form part of the RRRP funding calculation and RRRP payable to HORCI. The impact of HORCI recovering this amount through the RRRP pool is $0.48 per month, or 0.36% for a typical residential customer,[1] as detailed in Exhibit I-4-1. Exhibit I-4-1 also describes how the transmission rate charged to HORCI does not result in bill increases for HORCI's residential customers in remote communities.

The total bill impact for a typical residential customer arising from WPLP's 2024 revenue requirement is $0.54 per month, or 0.40%.

Details of bill impacts for typical general service customers and transmission-connected customers arising from WPLP's 2024 revenue requirement are provided in Exhibit I-4-1.

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[1] Throughout this Exhibit I, a typical residential customer is considered to be a Hydro One Networks Medium-Density (R1) customer, using 750 kWh/month on Time-of-Use rates.

Exhibit I, Tab 2, Schedule 1

Cost Allocation

COST ALLOCATION

A. WPLP's Cost Recovery and Rate Framework

In EB-2018-0190, WPLP requested OEB approval for a project-specific cost recovery and rate framework to support the unique funding and financing circumstances surrounding WPLP's project, which is summarized as follows:

> Under the proposed framework, the revenue requirement impacts arising from the Remote Connection Lines (based on direct and indirect capital expenditures and OM&A expenses) would be charged by WPLP through fixed monthly transmission rates applicable to service provided to HORCI from the Remote Connection Lines, which rates would be approved by the Board from time to time in future transmission rate proceedings. The revenue requirement impacts arising from all other in-service capital and OM&A costs would be recovered through the UTR. HORCI would include in its revenue requirement the costs it incurs to pay WPLP's transmission rates. In accordance with section 4(2.1) of the RRRP Regulation, the incremental amount in HORCI's revenue requirement attributable to the rates charged by WPLP would be recovered through the RRRP mechanism, while rates applicable to HORCI's customers would be expected to continue to be set based only on inflationary adjustments in accordance with the RRRP Regulation.[1]

In its decision and order in EB-2018-0190, the OEB approved the cost recovery and rate framework as requested.[2] As a result of that decision, and consistent with its prior rate applications, WPLP is required to allocate its total revenue requirement into two categories:

1. **Line to Pickle Lake –** network assets for which direct costs, and an allocation of indirect costs, will be recovered through the UTR Network rate; and

2. **Remote Connection Lines –** assets that would otherwise be categorized as line connection and transformation connection assets, for which direct costs, and an allocation of indirect costs, will be recovered through a monthly fixed charge applied to service provided to

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[1] EB-2018-0190; WPLP Reply Submission; February 15, 2019; pp. 24-25

[2] EB-2018-0190; Decision and Order; April 1, 2019; pp. 27-28

HORCI, in lieu of requiring a capital contribution and applying UTR Line and Transformation Connection rates.

Further detail on the categorization of WPLP's assets is provided in Exhibit B-2-1.

B. Rate Base

The rate base information from Exhibit C, summarized in Table 1 below, includes all direct capital costs as well as an allocation of overhead costs, as detailed in Appendix A of Exhibit B-1-5.

Table 1 – Rate Base by Category

Category	**Item**	**2024 Forecast ($000's)**		
		Opening	**Closing**	**12-Month Average**
LTPL	Gross Fixed Assets	290,703	322,315	320,998
	Less Accumulated Depreciation	-7,745	-14,171	-10,932
	Net Fixed Assets	**282,958**	**308,144**	**310,066**
	Working Capital Allowance	0	0	0
	Rate Base			**310,066**
	% of Transmission System Rate Base			**21.1%**
RCL	Gross Fixed Assets	822,866	1,424,248	1,180,567
	Less Accumulated Depreciation	-12,220	-35,491	-22,490
	Net Fixed Assets	**810,645**	**1,388,757**	**1,158,076**
	Working Capital Allowance	0	0	0
	Rate Base			**1,158,076**
	% of Transmission System Rate Base			**78.9%**
Sub-Total Transmission System		**1,093,603**	**1,696,901**	**1,468,142**
GP	Gross Fixed Assets	495	9,245	4,844
	Less Accumulated Depreciation	-59	-795	-380
	Net Fixed Assets	**437**	**8,451**	**4,464**
	Working Capital Allowance	0	0	0
	Rate Base			**4,464**
Total Rate Base				**1,472,606**

For the purpose of determining WPLP's 2024 revenue requirement and setting rates, rate base attributable to General Plant ("GP") assets (i.e. $4.4 million in 2024) is allocated 21.1% to the LTPL and 78.9% to the RCL based on the respective proportions of 2024 transmission system rate base for each category, as shown in Table 2.

Table 2 – Rate Base by Category with General Plant Allocations

Category	2024 Rate Base		
	Transmission System Assets	Allocation of GP Assets	Total
LTPL	310,066	943	311,008
RCL	1,158,076	3,521	1,161,598
Total	**1,468,142**	**4,464**	**1,472,606**

C. OM&A Expenses and Income Taxes

WPLP's 2024 OM&A includes expenses that are directly related to fixed assets, as well as an allocation of overheads, as detailed in Appendix A of Exhibit B-1-5. WPLP's 2024 income tax expense consists of the Ontario Corporate Minimum Tax payable by one of WPLP's partners, as detailed in Exhibit F-5-1.

Based on the calculations in Table 1, indirect OM&A costs for the 2024 test year are allocated 21.1% to the Line to Pickle Lake and 78.9% to the Remote Connection Lines, as illustrated in Table 3.

Table 3 – Allocation of 2024 OM&A and Income Tax Expense

	LTPL	**RCL**	**Total**
Direct OM&A Expenses	1,307,850	377,500	1,685,350
Indirect OM&A Expenses			29,298,337
Income Tax Expense			501,972
Allocation Factor from Table 1	*21.1%*	*78.9%*	*100%*
Allocation of Indirect OM&A	6,187,689	23,110,649	29,298,337
Allocation of Income Tax Expense	106,014	395,958	501,972
Total 2024 OM&A	**7,495,539**	**23,488,149**	**30,983,687**
Total 2024 Allocated Income Tax	**106,014**	**395,958**	**501,972**

D. Depreciation Expense

In Exhibit F-4-1, 2024 depreciation expenses are calculated separately for each of the Line to Pickle Lake and the Remote Connection Lines, based on the forecasted number of in-service months for assets in each category. Depreciation expenses related to General Plant are allocated between the Line to Pickle Lake and the Remote Connection Lines on the same 21.1%/78.9% basis described above. Table 4 below shows the depreciation expense for each rate category for the 2024 test year.

Table 4 – 2024 Depreciation Expense by Rate Category

	LTPL	**RCL**	**Total**
Depreciation Expense	6,582,078	23,851,013	30,433,091

E. Partial Disposition of Deferral Account Balances

As described in Exhibit H-2-1, WPLP is proposing to recover its proposed deferral and variance account dispositions as follows:

1. **Pikangikum Distribution System Deferral Account:** WPLP proposes to add the 2022 year-end balance inclusive of incurred and forecasted carrying charges of $1,899,734 to the portion of the 2024 base revenue requirement that is allocated to the Remote Connection Lines. Further detail on the proposed disposition and the appropriateness of allocating the entire amount to the Remote Connection Lines rate category is provided in Exhibit H-2-1. Recovery for this account is over 1 year, consistent with initial rate application and 2023 rate application.

2. **CCCDA:** In accordance with the OEB's decision in EB-2021-0134, WPLP has calculated that the amount of COVID-related construction costs from 2020 to be recovered in 2024, inclusive of applicable carrying costs as described in Exhibit H-2-1, is $5,042,957. WPLP records portions of this cost separately for the Line to Pickle Lake and the Remote Connection Lines. The costs included in Table 6 are based on direct tracking for each asset pool and no further cost allocation is required.

3. **ISDVA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the ISDVA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is required. Accordingly, WPLP proposes to dispose of the negative balance of $17,459,915, which is representative of the December 31, 2022 audited balance of $15,195,242 plus calculated carrying charges of $2,264,673[3] over a 4 year period. The disposal would be a balance of $(1,763,962) in the Line to Pickle Lake sub-account and a balance of $ (2,601,017) in the Remote Connection Line sub-account, by subtracting them from the respective revenue requirements, as further shown in Table 6 below.

4. **CPICVA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the CPICVA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is

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[3] See Exhibit H-2-1 – Attachment A which provides calculation tables for disposal over 4 years and forecasted carrying charges.

required. Accordingly, WPLP proposes to dispose of the balance of $3,906,251, which is representative of the December 31, 2022 audited balance of $3,395,782 plus calculated carrying charges of $510,469[4] over a 4 year period. WPLP proposes to dispose of the balance of $551,307 in the Line to Pickle Lake sub-account and the balance of $ 425,256 in the Remote Connection Line sub-account by adding them to the respective revenue requirements, as further shown in Table 6 below.

5. **DCDA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the DCDA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is required. Accordingly, WPLP proposes to dispose of the balance of $25,400, which is representative of the December 31, 2022 audited balance of $22,082 plus calculated carrying charges of $3,319[5] over a 4 year period. WPLP proposes to dispose of the balance of $ 5,747 in the Line to Pickle Lake sub-account and the balance of $603 in the Remote Connection Line sub-account by adding them to the respective revenue requirements, as further shown in Table 6 below.

Table 5 provides a summary of the balances in the various accounts that are subject to partial disposition.

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[4] See Exhibit H-2-1 – Attachment A which provides calculation tables of disposal over 4 years and forecasted carrying charges.

[5] See Exhibit H-2-1 – Attachment A which provides calculation tables of disposal over 4 years and forecasted carrying charges.

Table 5 – Partial Disposition of Deferral Account Balances

	2022 Audited Balances		**Forecasted Carrying Charges**		**2023 Approved Recoveries**		**Total[6]**	
	LTPL	**RCL**	**LTPL**	**RCL**	**LTPL**	**RCL**	**LTPL**	**RCL**
Disposition of Pikangikum Distribution System Deferral Account	-	$2,937,724	-	158,973	-	($1,196,963)	-	$1,899,734
Disposition of COVID Construction Costs Deferral Account (CCCDA)	$9,268,939	$5,605,220	692,974	300,827	($3,033,179)	($1,316,734)	$6,928,734	$4,589,313
Disposition of In-Service Date Variance Account (ISDVA)	($6,142,410)	($9,052,832)	($913,436)	($1,351,237)	-		($7,055,846)	($10,404,069)
Disposition of Construction Period Interest Costs Variance Account (CPICVA)	$1,917,349	$1,478,433	$287,880	$222,590	-		$2,205,229	$1,701,023
Disposition of Deferred Contingency Deferral Account (DCDA)	19,984	2,097	$3,002	$316	-		$22,986	$2,413
Total	**$5,168,001**	**($565,628)**	**$70,419**	**($668,531)**	**($3,033,179)**	**($2,513,697)**	**$2,101,103**	**($2,211,586)**

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[6] Dispositions for ISDVA, CPICVA and DCDA are ¼ of Total balances. Disposition for CCCDA is ¼ of principal balance approved in EB-2021-0134 plus audited carrying charges of $392,288 and forecasted carry charges recovered over 2 years as principal will be fully collected in 2 years. Pikangikum Distribution System Deferral Account is recovered over 1 year consistent with prior rate applications.

F. Allocation of Revenue Requirement

WPLP's 2024 revenue requirement for each of the Line to Pickle Lake and the Remote Connection Lines is summarized in Table 6, along with references to the relevant sections of the Application supporting each component of the revenue requirement.

Table 6 – Allocation of 2024 Revenue Requirement

	LTPL	**RCL**	**Total**	**Reference**
Gross Fixed Assets (avg)	322,021,112	1,184,387,681	1,506,408,792	C-3-1
Accumulated Depreciation (avg)	-11,012,718	-22,789,830	-33,802,548	C-3-1
Net Fixed Assets (avg)	311,008,394	1,161,597,851	1,472,606,245	C-1-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	311,008,394	1,161,597,851	1,472,606,245	C-1-1
Regulated Rate of Return	6.81%	6.81%	6.81%	G-2-1
Regulated Return on Rate Base	21,164,301	79,047,405	100,211,706	G-2-1
OM&A Expenses	7,495,539	23,488,149	30,983,687	F-2-1
Property Taxes	0	0	0	F-5-1
Depreciation Expense	6,582,078	23,851,013	30,433,091	F-4-1
Income Taxes	106,014	395,958	501,972	F-5-1
Service Revenue Requirement	**35,347,932**	**126,782,524**	**162,130,456**	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**35,347,932**	**126,782,524**	**162,130,456**	
Disposition of Pikangikum Distribution System Deferral Account	0	1,899,734	1,899,734	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	3,516,436	1,526,521	5,042,957	H-2-1
Disposition of In-Service Date Variance Account (ISDVA)	-1,763,962	-2,601,017	-4,364,979	H-2-1
Disposition of Period Interest Costs Variance Account (CPICVA)	551,307	425,256	976,563	H-2-1
Disposition of Deferred Contingency Deferral Account (DCDA)	5,747	603	6,350	H-2-1
Revenue Requirement for Rates	**37,657,460**	**128,033,622**	**165,691,082**	

Exhibit I, Tab 3, Schedule 1

Calculation of Uniform Transmission Rates

CALCULATION OF UNIFORM TRANSMISSION RATES

A. Overview

Transmission rates in Ontario were established on a uniform basis for all licensed transmitters in Ontario on April 30, 2002 as per RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044, and have generally been updated on an annual basis ever since. Uniform Transmission Rates ("UTRs") are determined by aggregating the most recent OEB-approved revenue requirements for each Ontario licensed transmitter, allocating those revenue requirements between the three UTR rate pools, and dividing the allocated revenue requirements by forecasted charge determinants. On December 8, 2022, the OEB issued its decision and rate order in EB-2022-0250 for the 2023 UTRs, effective January 1, 2023.

As described in Exhibit I-2-1, the portion of WPLP's revenue requirement associated with the Line to Pickle Lake, which is $37,657,460 for the 2024 test year, will be recovered through the UTR Network rate, as detailed in this schedule. As a result of the assets that WPLP expects to have in-service for all or part of 2024, WPLP is forecasting Network charge determinants of 156.2 MW, as detailed in Exhibit E-1-1.[1]

The addition of the above revenue requirement and charge determinants results in an increase of $0.03/kW, or 0.59%, to the Network UTR rate.

B. Current Uniform Transmission Rates

Table 1 below illustrates the calculation of the current UTRs, effective January 1, 2023, which includes WPLP's approved 2023 UTR revenue requirement. These values serve as the starting point for comparison in the tables that follow.

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[1] Additional amounts may be added to WPLP's rate base in respect of the Line to Pickle Lake (and Remote Connection Lines) in a future period upon disposition of any balance that may be recorded in the proposed EPC COVID-Related Costs Deferral Account.

Table 1 – Current UTR Calculations

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$4,765,263.00	$841,036	$2,381,792.00	$7,988,091
CNPI	$2,772,269	$489,287	$1,385,646	$4,647,202
WPLP	$29,243,172	$0	$0	$29,243,172
NextBridge	$54,003,549	$0	$0	$54,003,549
H1N SSM	$26,194,946	$4,623,229	$13,092,857	$43,911,032
H1N	$1,166,867,384	$205,944,134	$583,228,083	$1,956,039,601
B2MLP	$34,728,950	$0	$0	$34,728,950
NRLP	$8,388,996	$0	$0	$8,388,996
All Transmitters	$1,326,964,529	$211,897,686	$600,088,378	$2,138,950,593

Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	40.643	0.000	0.000	
NextBridge	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	232,792.251	225,964.444	192,218.503	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	237,084.434	229,497.186	193,476.053	

Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**5.60**	**0.92**	**3.10**	
	↓	↓	↓	
FNEI	0.00359	0.00397	0.00397	
CNPI	0.00209	0.00231	0.00231	
WPLP	0.02204	0.00000	0.00000	
NextBridge	0.04070	0.00000	0.00000	
H1N SSM	0.01974	0.02182	0.02182	
H1N	0.87935	0.97190	0.97190	
B2MLP	0.02617	0.00000	0.00000	
NRLP	0.00632	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

C. Calculation of 2024 Test Year UTRs

Table 2 below shows the calculation of 2024 UTRs, with the addition of WPLP's forecasted Network revenue requirement and charge determinants, and assuming that the values for all other transmitters remain the same as in EB-2022-0250. WPLP expects that the OEB will determine the actual 2024 UTRs once 2024 revenue requirements are approved for all other Ontario licensed transmitters.

WPLP has also provided an analysis of the changes in 2024 UTRs resulting from the current Application in Table 3 below.

Table 2 – Calculation of 2024 UTRs

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$4,765,263	$841,036	$2,381,792	$7,988,091
CNPI	$2,772,269	$489,287	$1,385,646	$4,647,202
WPLP	$37,657,460	$0	$0	$37,657,460
NextBridge	$54,003,549	$0	$0	$54,003,549
H1N SSM	$26,194,946	$4,623,229	$13,092,857	$43,911,032
H1N	$1,166,867,384	$205,944,134	$583,228,083	$1,956,039,601
B2MLP	$34,728,950	$0	$0	$34,728,950
NRLP	$8,388,996	$0	$0	$8,388,996
All Transmitters	$1,335,378,817	$211,897,686	$600,088,378	$2,147,364,881
Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	156.151	0.000	0.000	
NextBridge	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	232,792.251	225,964.444	192,218.503	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	237,199.942	229,497.186	193,476.053	
Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**5.63**	**0.92**	**3.10**	
	↓	↓	↓	
FNEI	0.00357	0.00397	0.00397	
CNPI	0.00208	0.00231	0.00231	
WPLP	0.02820	0.00000	0.00000	
NextBridge	0.04044	0.00000	0.00000	
H1N SSM	0.01962	0.02182	0.02182	
H1N	0.87380	0.97190	0.97190	
B2MLP	0.02601	0.00000	0.00000	
NRLP	0.00628	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Table 3 – Changes in 2024 UTRs Resulting from this Application

Transmitter	**Change in Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	-	-	-	-
CNPI	-	-	-	-
WPLP	$8,414,288	$0	$0	$8,414,288
NextBridge	-	-	-	-
H1N SSM	-	-	-	-
H1N	-	-	-	-
B2MLP	-	-	-	-
NRLP	-	-	-	-
All Transmitters	$8,411,072	$0	$0	$8,411,072
Transmitter	**Change in Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	-	-	-	
CNPI	-	-	-	
WPLP	115.508	-	-	
NextBridge	-	-	-	
H1N SSM	-	-	-	
H1N	-	-	-	
B2MLP	-	-	-	
NRLP	-	-	-	
All Transmitters	115.508	-	-	
Transmitter	**Change in Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**0.03**	**0.00**	**0.00**	
	↓	↓	↓	
FNEI	-0.00002	-	-	
CNPI	-0.00001	-	-	
WPLP	0.00616	-	-	
NextBridge	-0.00026			
H1N SSM	-0.00012	-	-	
H1N	-0.00555	-	-	
B2MLP	-0.00016	-	-	
NRLP	-0.00004	-	-	
Total of Allocation Factors	0.00000	-	-	

D. Revenue Reconciliation

Table 4 below compares WPLP's forecasted 2024 revenue, based on the rates and charge determinants in Table 2, with the 2024 revenue requirement calculated in Exhibit I-2-1.

Table 4 – 2024 Revenue Reconciliation

2024 Network Charge Determinants (kW)	237,199,942
2024 Network UTR Rate ($/kW)	$5.63
2024 WPLP Network Allocation Factor	0.02820
2024 Revenue Forecast	$37,657,683
2024 WPLP LTPL Revenue Requirement	$37,657,460
Difference due to Rounding	$222
	0.001%

Exhibit I, Tab 3, Schedule 2

Monthly Fixed Charge to Hydro One Remotes

EB-2023-0168
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MONTHLY FIXED CHARGE TO HYDRO ONE REMOTES

In accordance with the OEB's Decision and Order in EB-2018-0190 and consistent with the approach taken by WPLP and approved by the OEB in WPLP's prior rate proceedings (EB-2021-0134 and EB-2022-0149), WPLP will recover the portion of its revenue requirement associated with the Remote Connection Lines through a fixed monthly charge applicable to HORCI, effective from January 1, 2024.

WPLP's 2024 revenue requirement attributable to the Remote Connection Lines is $128,033,622. This amount includes an allocated base revenue requirement of $126,782,524, as detailed in Exhibit I-2-1, and interim disposition of deferral and variance accounts of $1,251,097, as summarized in Exhibit H-2-1 and Exhibit I-2-1. Recovering this amount through a fixed charge to HORCI over the 12-month period from January to December 2024 results in a fixed monthly charge of $10,669,468 that would apply for each month from January 2024 to December 2024.

Exhibit I, Tab 4, Schedule 1

Bill Impacts

BILL IMPACTS

This schedule details the bill impacts for typical Ontario residential and general service distribution customers, as well as for an average transmission-connected customer, resulting from WPLP's proposed changes to its revenue requirement for 2024.

The bill impacts discussed in this schedule do not include any offsetting reductions to the portion of HORCI's existing revenue requirement related to the purchase of diesel fuel or the impact of any future changes in the revenue that HORCI receives from rates. Additionally, the RRRP rate impacts do not include the impact of any amounts provided under the Federal Funding Framework, which WPLP anticipates receiving in 2024, as discussed in Part E of this Schedule. The bill impacts do reflect the use of the actual debt to equity structure as compared to the deemed debt to equity structure, as agreed to under the Federal Funding Framework to calculate WPLP's revenue requirements (discussed in Exhibit G-2-1).

The bill impacts discussed in this schedule are reflective of typical Hydro One customers and average transmission-connected customers, with references to the sources of information used to calculate each bill impact. Importantly, WPLP notes that Non-Standard A customers of HORCI in the connecting communities and other remote communities will not experience bill impacts resulting from WPLP's 2024 revenue requirement, because the rates for those customers are determined through relevant RRRP regulations and do not include components for Network UTR charges or RRRP charges. Additionally, Standard A customers in the connecting communities will experience significant bill reductions upon grid connection, due to HORCI's Standard A rates being significantly lower for grid-connected communities as compared to air-access non-grid-connected communities.[1]

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[1] HORCI's Standard A rates effective May 1, 2023 range from $1.0498-$1.1489/kWh for Air Access (non-grid-connected) communities vs. $0.3599/kWh for grid-connected communities.

A. Bill Impacts for Distribution-Connected Customers

The total bill impact of this application for a typical residential customer is an increase of approximately $0.54 per month, or 0.40%, and the total bill impact of this application for a typical General Service customer is an increase of approximately $1.45 per month, or 0.34%, as summarized in Table 1.

Table 1 – Summary of Total 2024 Bill Impact

Item	**Description**	**Amount**[2]	
		Residential	**General Service**
A	Typical monthly bill	$135.97[3]	$428.31[4]
B	Increase related to Network RTSR	$0.05	$0.11
C	Increase related to RRRP rate	$0.49	$1.33
D = B + C	Total bill increase	$0.54	$1.45
E = D / A	Bill impact (%)	0.40%	0.34%

B. Bill Impact Resulting from Line to Pickle Lake

As calculated in Exhibit I-3-1, the portion of WPLP's 2024 revenue requirement associated with the Line to Pickle and allocated to the UTR Network rate pool results in an increase in the UTR Network rate of $0.03/kw, or 0.585%. The resulting bill impact of this application for a typical residential customer is an increase of 0.04%, and the resulting bill impact of this application for a typical General Service customer is an increase of 0.03%, as calculated in Table 2.

Table 2 – Bill Impact – Line to Pickle Lake

Item	**Description**	**Amount**

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[2] All amounts are inclusive of 13% HST and the Ontario Electricity Rebate.

[3] Total bill amount for a Hydro One R1 TOU customer (750 kWh per month), as indicated in the OEB's online bill calculator (https://www.oeb.ca/rates-and-your-bill/bill-calculator), as at April 30, 2023.

[4] Total bill amount for a Hydro One General Service Energy Billed TOU customer (2000 kWh per month), as indicated in the OEB's online bill calculator, as at April 30, 2023.

		Residential	**General Service**
A	Typical monthly bill (see Table 1)	$135.97	$428.31
B	Portion of bill related to Network RTSR	$9.00[5]	$19.32[6]
C	Increase in Network UTR	0.59%	0.59%
D = B x C	Bill increase	$0.05	$0.11
E = D / A	Bill impact (%)	0.04%	0.03%

C. Bill Impact Resulting from Remote Connection Lines

As described in Exhibit I-2-1, the OEB approved a cost recovery and rate framework whereby the portion of WPLP's revenue requirement allocated to the Remote Connection Lines will be recovered from HORCI, which in turn will add its cost for paying these amounts to its revenue requirement. In accordance with section 4(2.1) of the RRRP Regulation (O. Reg. 442/01), these incremental amounts in HORCI's revenue requirement will be recovered through RRRP funding. Importantly, WPLP expects that rates applicable to HORCI's non-Standard A customers will continue to be set based only on inflationary adjustments in accordance with the RRRP Regulation, such that HORCI's costs of receiving transmission service from WPLP will not result in an incremental bill impact for these customers. Table 3 calculates the 2024 RRRP rate, based on the assumption that the RRRP rate will be used for recovery by HORCI of 100% of the fixed charges that it pays to WPLP, and keeping all other values the same as 2023.

Table 3 – RRRP Rate Calculation

	2023	**2024**	**Change**
First Nations (O. Reg. 442/01, schedule 1)	$1,600,000	$1,600,000	$0
Algoma Power	$16,490,664	$16,490,664	$0
Hydro One Remote Communities Inc.	$47,921,000	$47,921,000	$0

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[5] HONI R1 Network RTSR Rate of $0.0110/kWh * 750 kWh * 1.076 loss factor = $8.88 ($9.00 after 13% HST and 11.7% Ontario Electricity Rebate).

[6] HONI GSe Network RTSR Rate of $0.0087/kWh * 2000 kWh * 1.096 loss factor = $19.07 ($19.32 after 13% HST and 11.7% Ontario Electricity Rebate)

Hydro One Remote Communities Inc. - WPLP	$54,020,437	$128,033,622	$74,013,185
Total RRRP Funding Required[7]	***$120,032,101***	***$194,045,286***	***$74,013,185***
Ontario TWh	133.8	133.8	0
RRRP Rate (Calculated)	$0.000897	$0.001450	$0.000553
RRRP Rate (Rounded to 4 Decimals)	$0.0009	$0.0015	$0.0006

The calculation in Table 3 shows that the calculated RRRP rate rounded to 4 decimal places would increase by $0.0006/kWh. WPLP has calculated the typical residential bill impact resulting from this change in Table 4 below.

Table 4 – RRRP Bill Impact Calculations

Item	**Description**	**Amount**	
		Residential	**General Service**
A	Typical monthly bill (see Table 1)	$135.97	$428.31
B	RRRP rate increase ($/kWh)	$0.0006	$0.0006
C = kWh * 1.076/1.096	Uplifted consumption (kWh)	807	2,192
D = B x C	Bill increase due to RRRP	$0.48	$1.32
E = D * (1+ 0.13 – 0.117)	Bill increase adjusted for HST and OER	$0.49	$1.33
F	Bill impact (%)	0.36%	0.31%

D. Bill Impacts for Transmission-Connected Customers

WPLP has calculated the estimated bill impact of this application for an average transmission-connected customer resulting from its 2024 revenue requirement, as detailed in Table 5, below. WPLP relied on the IESO's December 2022 Year-to-Date weighted average wholesale market

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[7] RRRP variance account balances have been omitted from this analysis in order to isolate the impact of the RRRP funding requested in this application. Similarly, the 2024 RRRP funding requirements for parties other than WPLP have been held constant from 2023 to 2024 for the purpose of bill impact analysis. WPLP expects that the OEB will consider the RRRP variance account balance and changes to 2024 RRRP funding for other parties when it determines the 2024 RRRP rate in due course.

electricity charges[8] and as such the calculated percentage increases reflect a customer with an Ontario-average demand profile.

Table 5 – Transmission-Connected Customer Bill Impacts

Item	Description	Amount
A	Total Wholesale Market Charges ($/MWh)	120.02
B	Total Wholesale Transmission Charges ($/MWh)	14.23
C = B / A	Transmission % of Total Bill	11.86%
D	% Increase in Transmission Revenue Requirement	0.39%
E = C * D	% Bill Increase from Line to Pickle Lake	0.05%
F	Total RRRP Charges ($/MWh)	0.50
G = F / A	RRRP % of Total Bill	0.42%
H	% Increase in RRRP Rate	67%
I = G * H	% Bill Increase from Remote Connection Lines	0.28%
J = E + I	**Total % Bill Increase**	**0.32%**

E. Federal Funding Framework

In EB-2018-0190, WPLP described a contemplated Federal Funding Framework relating to its project, resulting from a March 12, 2018 Memorandum of Understanding between WPLP, Canada and Ontario.[9] The mechanics and conditions of the contemplated funding, as well as clarifications resulting from interrogatories, were summarized in WPLP's February 15, 2019 Reply Submission.[10] At a high level, Canada will provide $1.55 billion in funding in relation to the project, which will serve to reduce the resulting ratepayer impact in two ways:

a) a portion of the funding will be applied as a Contribution in Aid of Construction ("CIAC"), reducing WPLP's rate base in respect of the Remote Connection Lines; and,

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[8] https://www.ieso.ca/en/Power-Data/Monthly-Market-Report – Generated for December 2022

[9] EB-2018-0190, Exhibit J-1-2.

[10] EB-2018-0190, WPLP Reply Submission, February 15, 2019, pp. 27-29.

b) the remainder of the funding would be provided to an independent Trust which will use the funding to help offset the impacts of the Remote Connection Lines on RRRP for Ontario ratepayers.

The portion of funding that would be provided to WPLP as a CIAC will be determined by WPLP's total project costs. As WPLP's costs increase, the CIAC amount increases at a rate that reduces WPLP's deemed equity position in the project, thereby providing a strong incentive to control and reduce costs during construction. Reductions to WPLP's rate base in respect of the Remote Connection Lines resulting from the CIAC treatment of federal funding would therefore result in a reduction to the fixed monthly charges that WPLP will recover from HORCI, which will in turn result in HORCI needing to collect less revenue from the RRRP pool. Funding provided to the independent Trust will further reduce rate impacts for Ontario ratepayers because the independent Trust will be required to provide funds to the IESO to be applied against the total RRRP funding that the IESO needs to collect from Ontario ratepayers each month, until such time as the independent Trust's funds are exhausted.

On July 3, 2019, WPLP, Canada and Ontario signed definitive documents regarding the Federal Funding Framework for the project. While funding remains conditional on appropriation by Parliament of the required funds, the definitive documents solidify the mechanics by which the funding would be provided.

WPLP anticipates that the distribution of funds will occur at the end of 2024, following the later of: (a) the OEB's Decision and Order in respect of this Application; or (b) completion of construction and receipt of funds by the independent Trustee. For purposes of rate-setting, WPLP forecasts that it will receive the CIAC on December 31, 2024. As discussed in Exhibit H-1-1, WPLP has proposed to establish the Federal CIAC Variance Account to record the revenue requirement impact of receiving the CIAC earlier or later than this forecast date.

Accordingly, the bill impacts presented in this Application do not consider any potential reductions resulting from the receipt of federal funding, though they do reflect the use of the actual debt to equity structure which has the effect of reducing rates in accordance with the federal funding framework. This Application incorporates the impact of federal funding on a forecast basis.