## 1 - OEB Staff - 1

Reference:

Exhibit 1

Question:

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that EnWin Utilities wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

Response:

An updated Revenue Requirement Workform has been submitted including a tracking sheet with references to changes made since the April 26, 2019 submission.

## 1 - OEB Staff - 2

Reference:

Exhibit 1

Question:

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Tariff Schedule and Bill Impact model for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

---

Response:

A revised Tariff Schedule and Bill Impact model has been filed along with these interrogatory responses. The revised model incorporates the changes from the revised Cost Allocation Model and Revenue Requirement Work Form.

## 1 - OEB Staff - 3

Reference:

Exhibit 1, Page 65

Preamble:

EnWin Utilities states that "Enwin intends to conduct a second phase of application specific customer engagement. The purpose of this second phase is to follow up with customers, but in any event, a statistically relevant sample, in order to confirm that Enwin has captured the priorities, needs and preferences and struck an appropriate balance between cost and reliability in its DSP and other proposals submitted with this Application. Results from the second phase consultation will be filed with the Board subsequent to the filing of this Application."

Question:

a) Please provide the details of this second phase of consultation and the results of the consultation.

b) Please explain the reasons if the consultation has not been conducted to date.

---

Response:

a) As stated in Exhibit 1, Section 1.7.4 of ENWIN's application, a second phase of application-specific customer engagement was undertaken in May of 2019. Telephone surveys were conducted amongst a random sample of ENWIN's customers. A summary of the results of the consultation can be found in OEB Staff 3 - Attachment 1.

b) Not applicable, as the consultation has already been conducted.

Attachment 1: ENWIN Utilities Ltd. Customer Engagement Survey Report, dated June, 2019.

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# ENWIN Utilities Ltd.

## Customer Engagement Survey Report

*This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of ENWIN Utilities Ltd.*

**June 2019**

STRICTLY PRIVILEGED AND CONFIDENTIAL

# Key Findings

## Customer Engagement/Re-Engagement Survey

**57%**
**60%**

Most residential (57%) and small business (60%) customers say they were at least somewhat familiar with how distribution rates are set in Ontario prior to hearing the preamble provided at the outset of the survey.

**63%**
**63%**

More than three-in-five residential (63%) and small business (63%) trust that ENWIN will consider customer input as they prepare their rate application.

1
2
3

**93%**
**94%**

Almost all (93% residential, 94% small business) agree with the three most important priorities identified by ENWIN (price, reliability and safety).

**77%**
**72%**

While customers in both rate classes feel that improved customer communication/services warrant investment, they feel that cyber security and especially system reliability and grid maintenance are more urgent investment priorities.

**75%**
**67%**

Three-quarters (75%) of residential customers give social permission for the proposed plan – in fact, 39% feel it is reasonable and they support it.

Two-thirds (67%) of small business customers give social permission for the proposed plan.

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# Methodology & Respondent Profiles

# Survey Methodology

## Survey Design

This report documents the results of telephone surveys conducted by INNOVATIVE among ENWIN's low-volume customers (small business and residential). The respondent base is a combination of re-engagement interviews with customers who completed a similar survey (also conducted by INNOVATIVE) in April of 2017, and customers who had not completed the prior survey. In the April 2017 survey, respondents were provided with bill impact that was based on plans and impact estimates that were available at that time. As such, respondents of the 2017 survey had been exposed to earlier estimates of a higher rate impact than the current 2019 estimates.

The breakdown of re-engagement versus newly engaged customers is provided on the following slide.

The **telephone surveys** were fielded from **May 8th to May 28th, 2019** amongst a random sample of **n=517** residential and **n=193** small business customers.

The sample for both surveys were stratified based on consumption quartiles within their respective rate classes to produce a representative sample of ENWIN's customer base.

The final sample includes both landline and cell phone respondents so that individuals who don't have a landline are represented. The margin of error is approximately ±4.5%, 19 times out of 20 for the residential survey and approximately ±6.9%, 19 times out of 20 for the small business survey.

## Sample Design

ENWIN provided INNOVATIVE with confidential access to its customer lists in order to conduct this research. The customer list included information on region, electricity consumption, and preferred language for communications, as well as all available telephone numbers and email addresses. INNOVATIVE used the list of respondents from the 2017 survey to attempt to re-engage as many of those customers as possible.

**Note**: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

# Survey Sample

**The residential and small business telephone surveys utilized a stratified random sampling methodology**. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on a group's shared attributes or characteristics (in this case, customer electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

Both residential and small business (GS<50kW) customers were divided into quartiles based on annual electricity usage to ensure the sample has a proportionate mix of customers from *low*, *medium-low*, *medium-high*, and *high* electricity usage households and businesses.

## Residential Sample

| Consumption Quartile | Re-Engagement | New Completes | Total |
|---|---|---|---|
| Low consumption | 26 | 104 | 130 |
| Medium-low consumption | 37 | 92 | 129 |
| Medium-high consumption | 40 | 89 | 129 |
| High consumption | 39 | 90 | 129 |
| **Total** | **n=142** | **n=375** | **n=517** |

## Small Business (GS<50kW) Sample

| Consumption Quartile | Re-Engagement | New Completes | Total |
|---|---|---|---|
| Low consumption | 4 | 45 | 49 |
| Medium-low consumption | 7 | 41 | 48 |
| Medium-high consumption | 5 | 43 | 48 |
| High consumption | 3 | 43 | 48 |
| **Total** | **n=19** | **n=174** | **n=193** |

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# Engagement Process

## Familiarity & Trust

# Customer Engagement Process

## Preamble

"*As you may know, the electricity industry in Ontario is regulated by the Ontario Energy Board, which sets electricity rates in the province.*

*The Ontario Energy Board requires electricity distributors, such as ENWIN, to develop its plans, as well as make spending and investment decisions based on customer feedback.*

*Your feedback has and will continue to inform ENWIN' rate application. Customer feedback will be presented to the Ontario Energy Board and intervenors – who represent various groups of customers – as ENWIN's rate application moves through the Ontario Energy Board's defined process.*

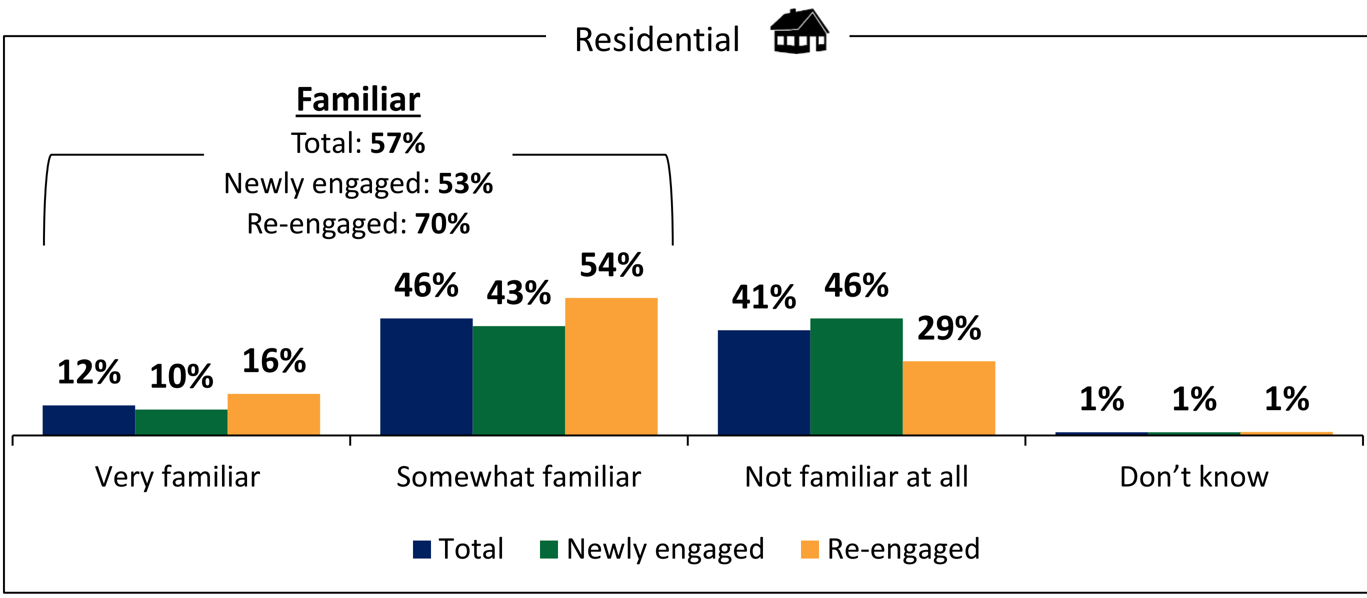
*As part of any rate hearing process, the Ontario Energy Board will review how ENWIN acquired and responded to customer feedback in its planning process.*"

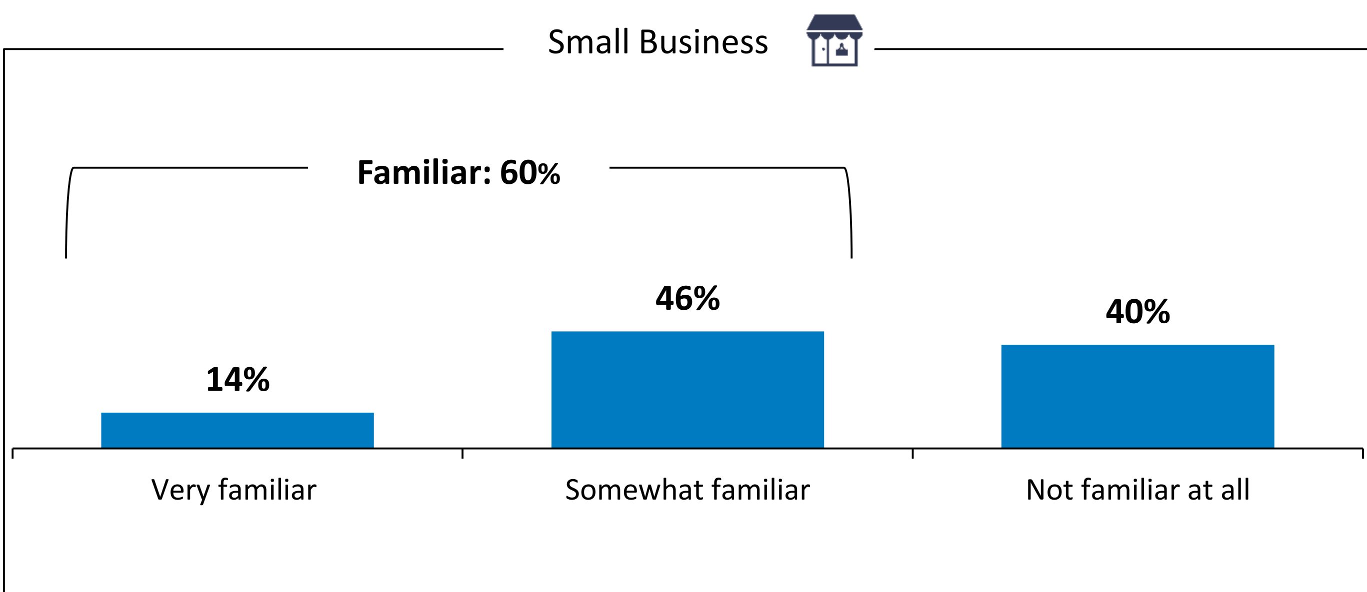
# Familiarity with Rate Setting

## Most say they are familiar with how rates are set

Q

Before this survey, how familiar were you with how electricity distribution rates are set in Ontario? Would you say you are very familiar, somewhat familiar, or not familiar at all?
[asked of all respondents]

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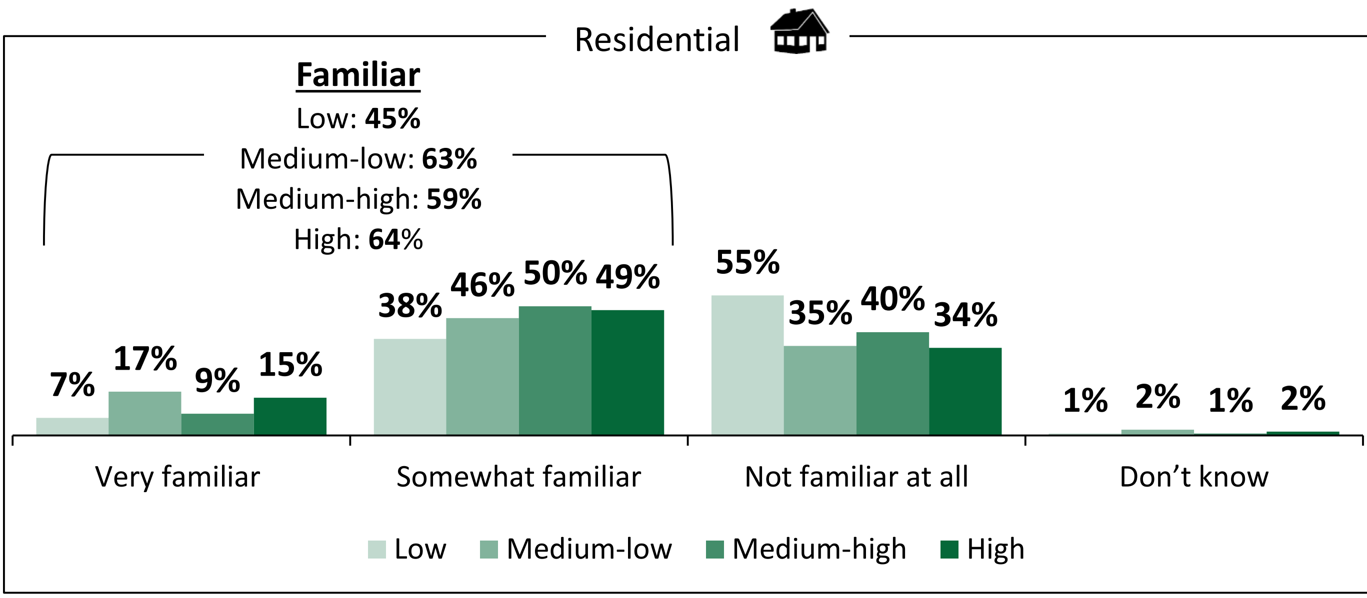
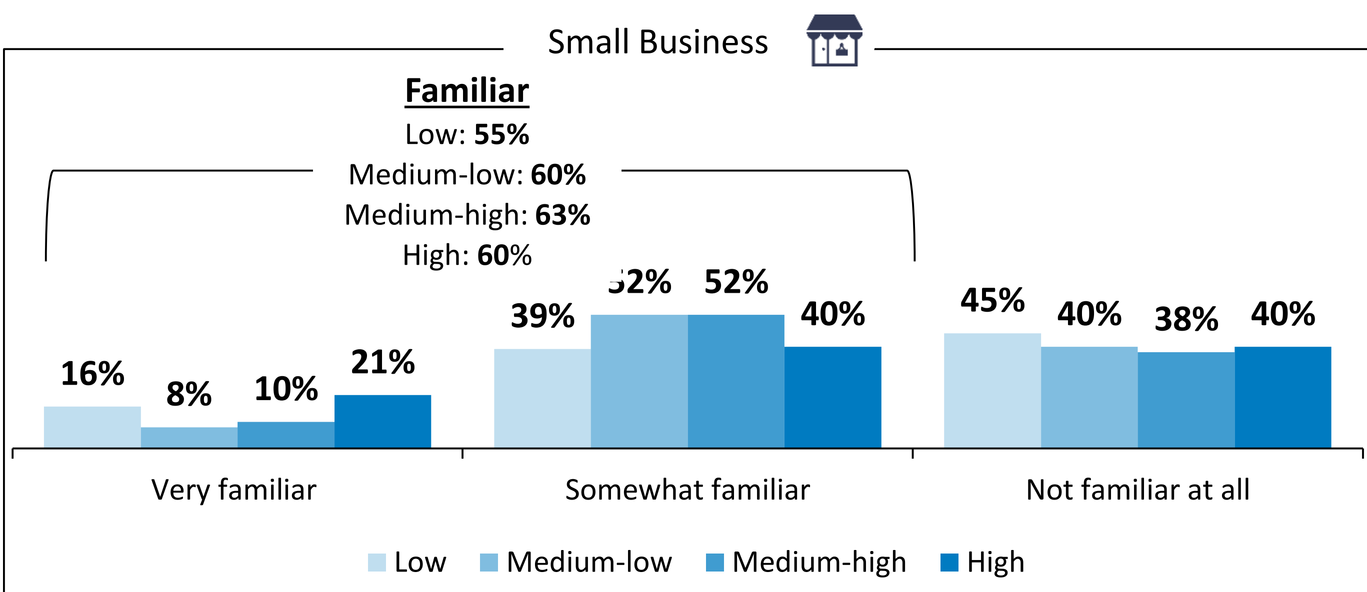
Note: sums added before rounding.

# Familiarity with Rate Setting

## BY CONSUMPTION QUARTILE

Q Before this survey, how familiar were you with how electricity distribution rates are set in Ontario? Would you say you are very familiar, somewhat familiar, or not familiar at all?
[asked of all respondents]




Note: sums added before rounding.

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# Trusting ENWIN

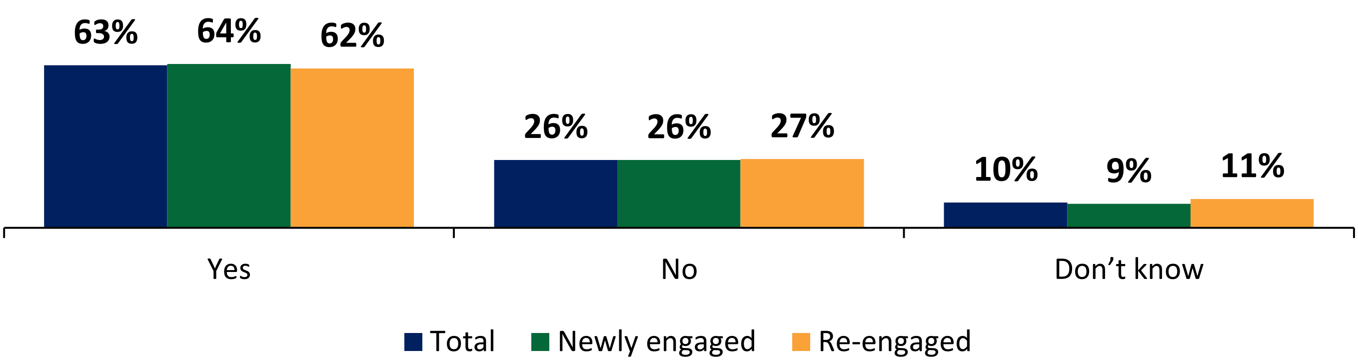
## 3-in-5 residential and small business customers trust ENWIN

Q

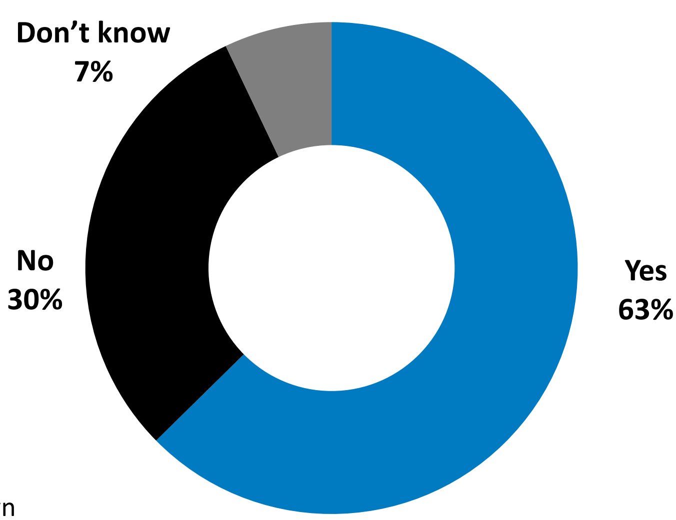
Since 2017, ENWIN has directly engaged with thousands of customers to better understand their needs and preferences. This has included customer workshops, focus groups, interviews, online surveys and telephone surveys, like this.

Do you trust that ENWIN will consider customers' views and feedback, as they prepare their rate application for submission to the Ontario Energy Board?
[asked of all respondents]

Residential




Small Business




**NOTE**: Refused (1%) not shown

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# ENWIN's Planning Priorities

# Customer Priorities

## Preamble

"*In discussions over the past two years in preparation for this application, ENWIN customers have identified a diverse range of customer stated priorities, ranging from price and reliability to customer service, outages and helping customers conserve electricity.*

*Understanding that not all customers value and prioritize the same things, ENWIN has been working to find a balance that works for all customers.*"

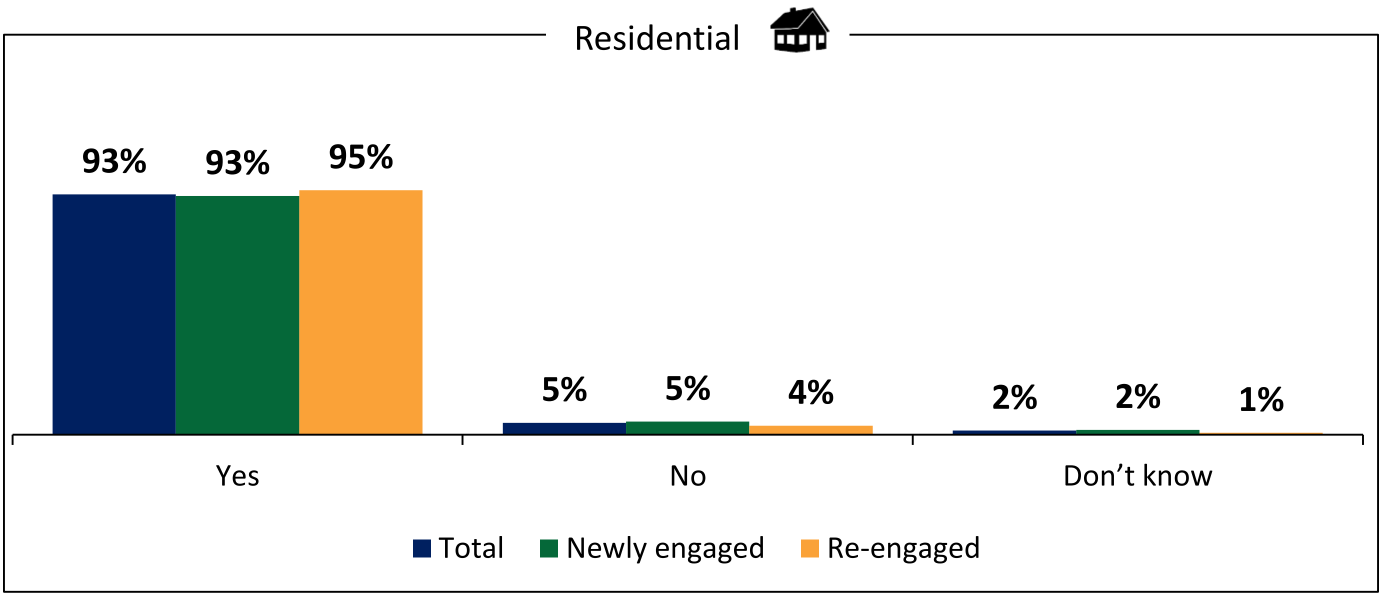
# Priority Alignment

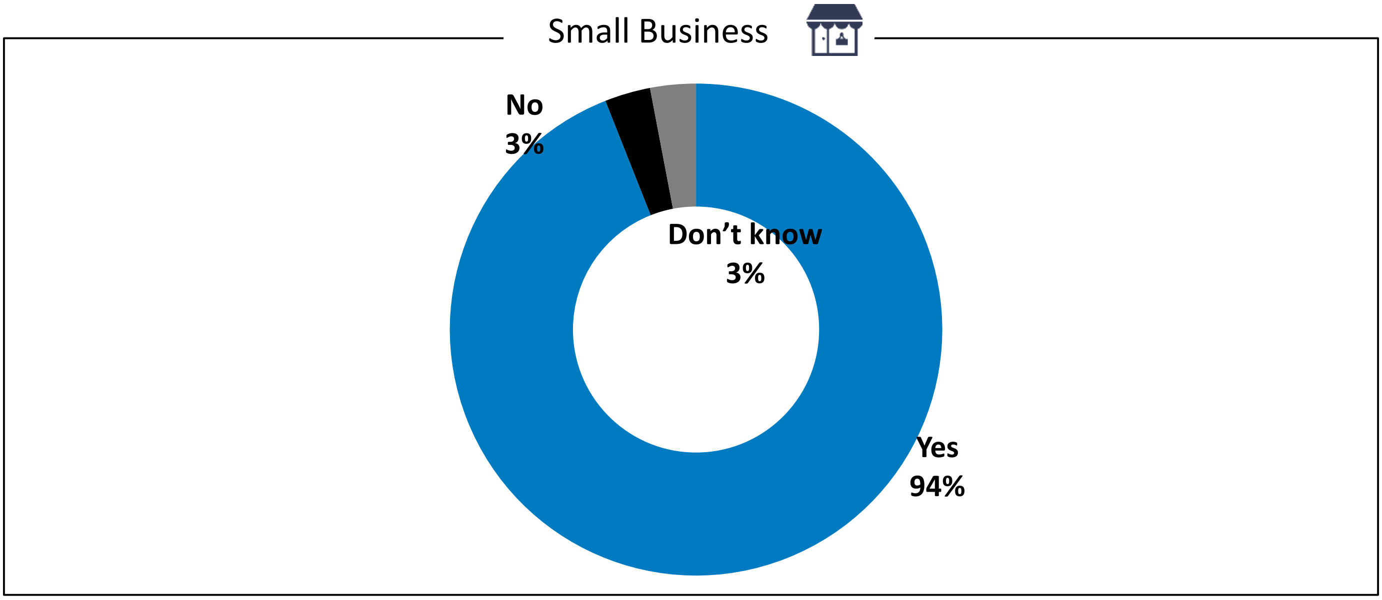
## Vast majority of customers agree with ENWIN's priorities

Q

In April 2017, residential customers told us that their three most important priorities were: 1) Delivering electricity at a reasonable price; 2) Ensuring reliable electrical service, and; 3) Ensuring the safety of electrical infrastructure.

Are these three customer identified priorities aligned with what you expect ENWIN to focus on?
[asked of all respondents]



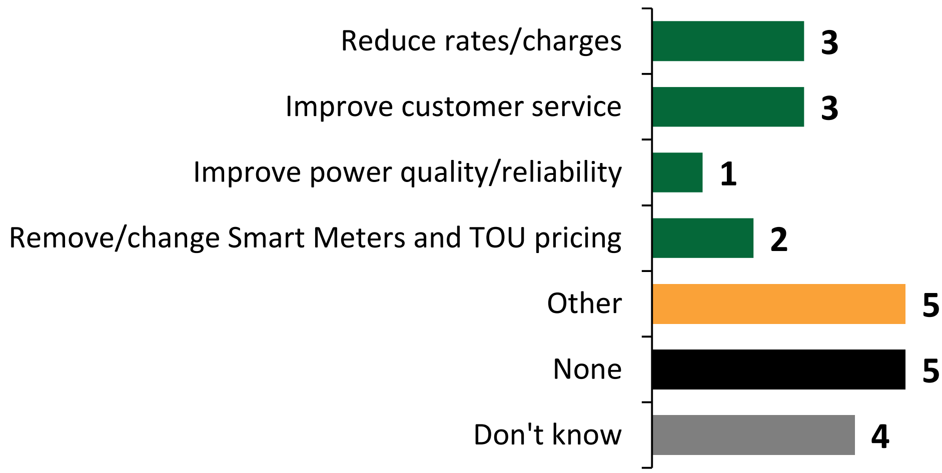
# Suggested Other Priorities

## CODED RESPONSES

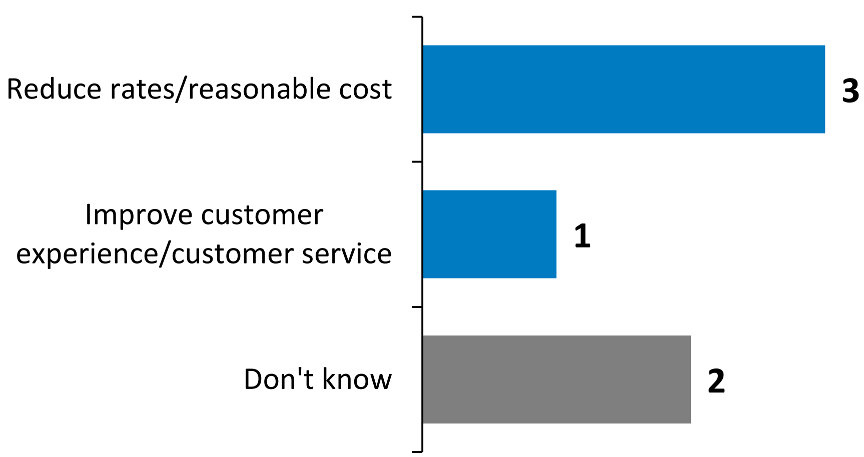
Q Are there any other priorities that you would rank ahead of delivering electricity at a reasonable price, ensuring reliable electrical service, and ensuring the safety of electrical infrastructure that ENWIN should focus on?

[asked of respondents who feel customer priorities are NOT aligned with their expectations; residential n=24, small business n=6]

### Residential




### Small Business



# Suggested Other Priorities

## VERBATIM CUSTOMER COMMENTS

Q Are there any other priorities that you would rank ahead of delivering electricity at a reasonable price, ensuring reliable electrical service, and ensuring the safety of electrical infrastructure that ENWIN should focus on?

[asked of respondents who feel customer priorities are NOT aligned with their expectations; residential n=5, small business n=4]

**Residential**

*"Customer service, because I've dealt with them and never talked to a real person."*

*"Fair cost."*

*"Focus on renewable energy. Focus on LED lights for lighting. Encourage to put up sky-lights or sunlights to improve energy conservation."*

*"They should focus on the rate because the rate is a little high for me."*

*"I think conservation would help customers save money in the long run. as opposed to lower rates."*

---

**Small Business**

*"Cost. They need to bring down some of the management wages and the Board Directors."*

*"I would like one of their priorities to be helping small business achieve reasonable pricing costs."*

*"Prioritize customers."*

*"I would like to see conservation measures. It's extremely complicated the information is presented to us, to save on energy and money. Trying to find the program that matches that is very limited."*

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# ENWIN's Plan

## Cyber Security, Customer Communications, System Maintenance/Upgrades

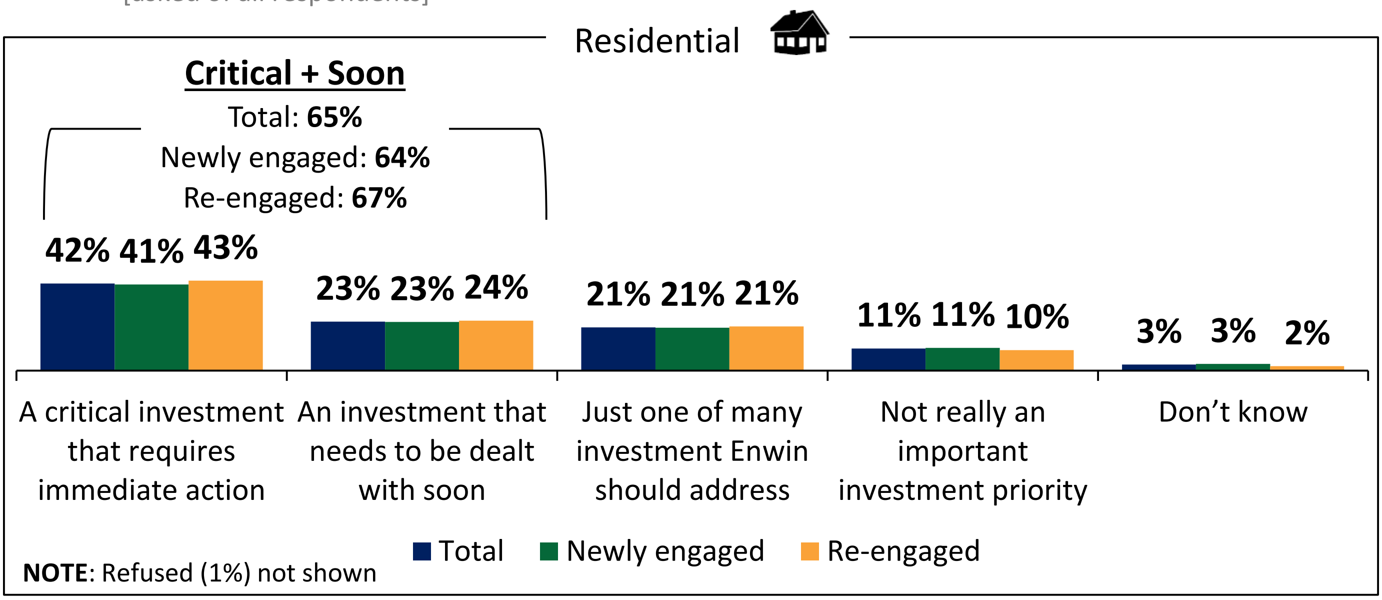
# Cyber Security

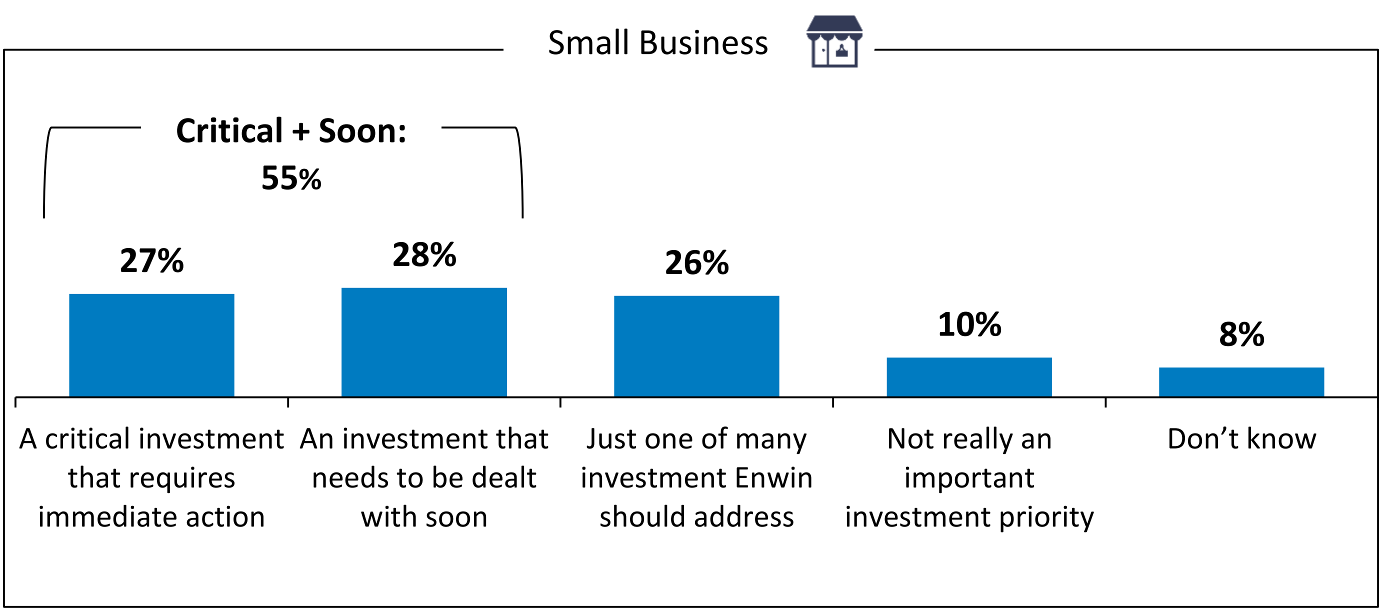
## Most feel cyber security investments need action urgently

Q

Stored data is becoming a greater part of doing business, and companies world-wide have become increasingly aware of the risks of cyber-attacks. These attacks can put customer information at risk, or attempt to harm or take down the distribution system. ENWIN's proposed plan includes investment in ensuring that important data is secure from cyber-attack.

How important are investments in the cyber security?
[asked of all respondents]

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Note: sums added before rounding.

# Customer Communications/Services

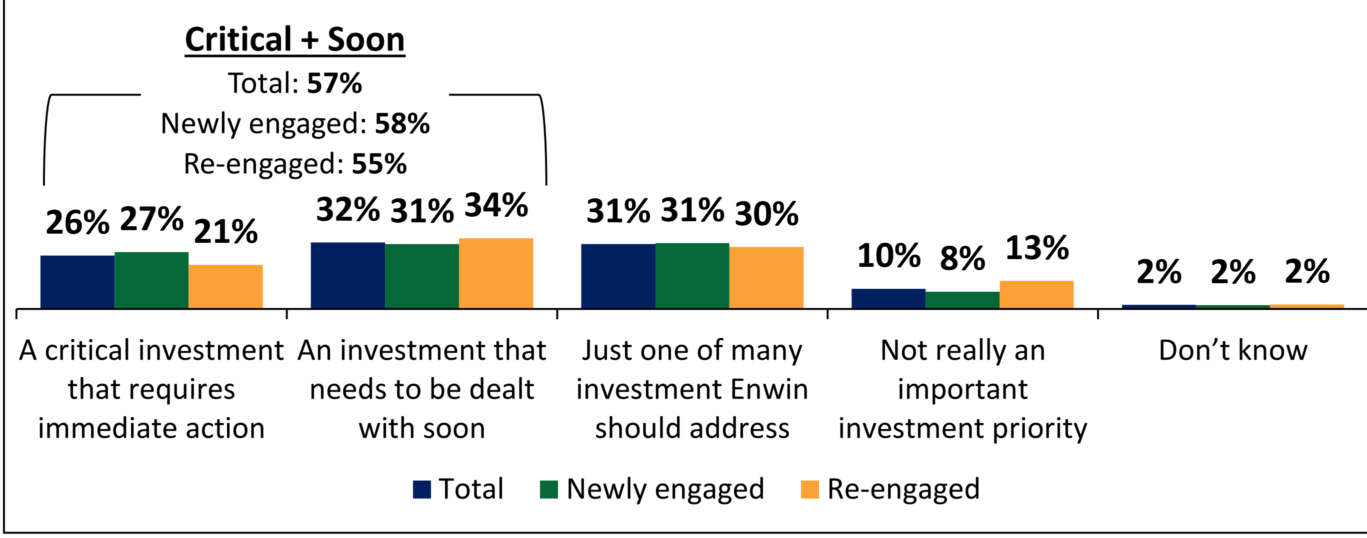
## Residential customers want investment here more than GS

Q

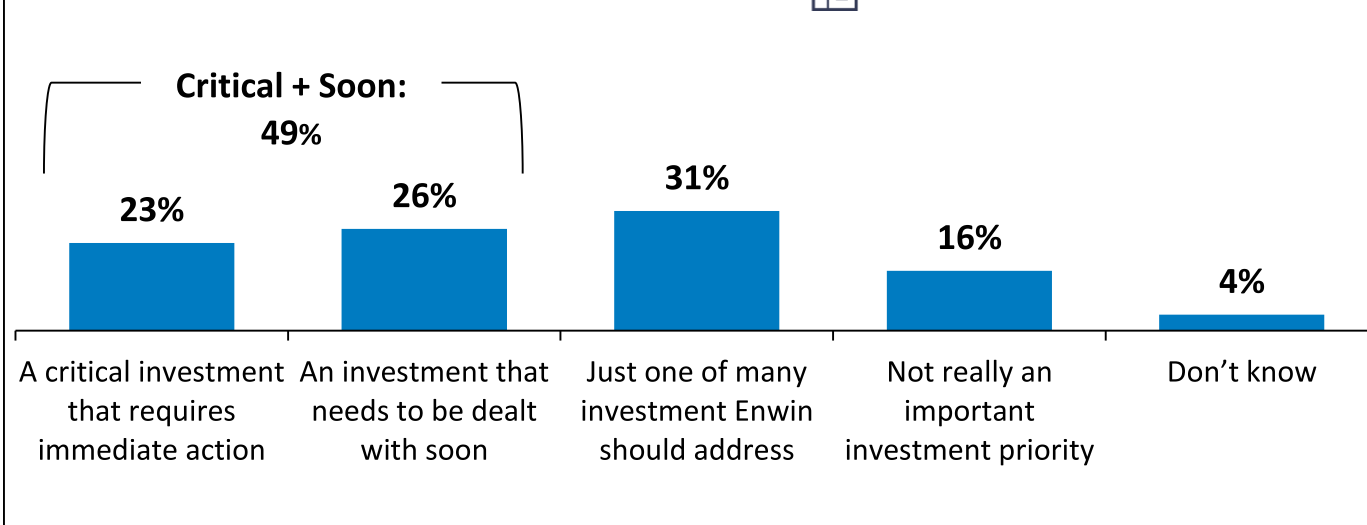
ENWIN has included in its plan some measures to improve customer services and communications, including web portals and online self-serve options. This planning responds to previous customer input, which indicted that customers -- particularly business customers -- place importance on proactive communication and would like help with understanding how to reduce the electricity consumption and costs.

How important are investments in improved customer communications and services?
[asked of all respondents]

Residential




Small Business

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Note: sums added before rounding.

# System Reliability & Modernization

## Almost half of residential customers want immediate action

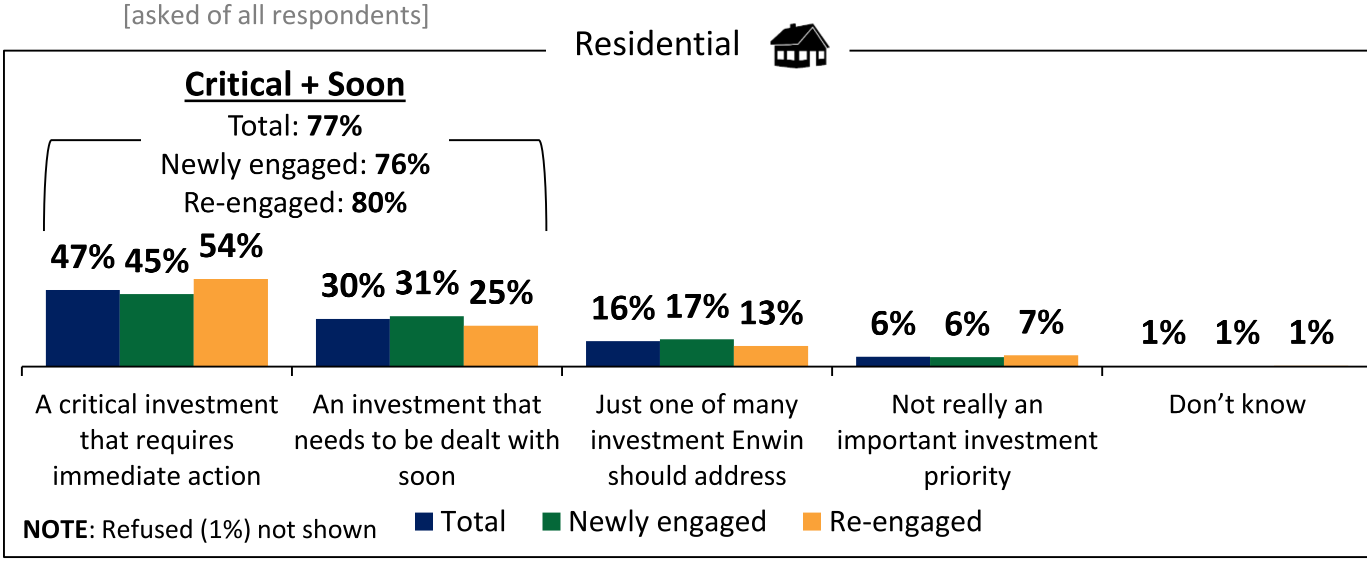
Q

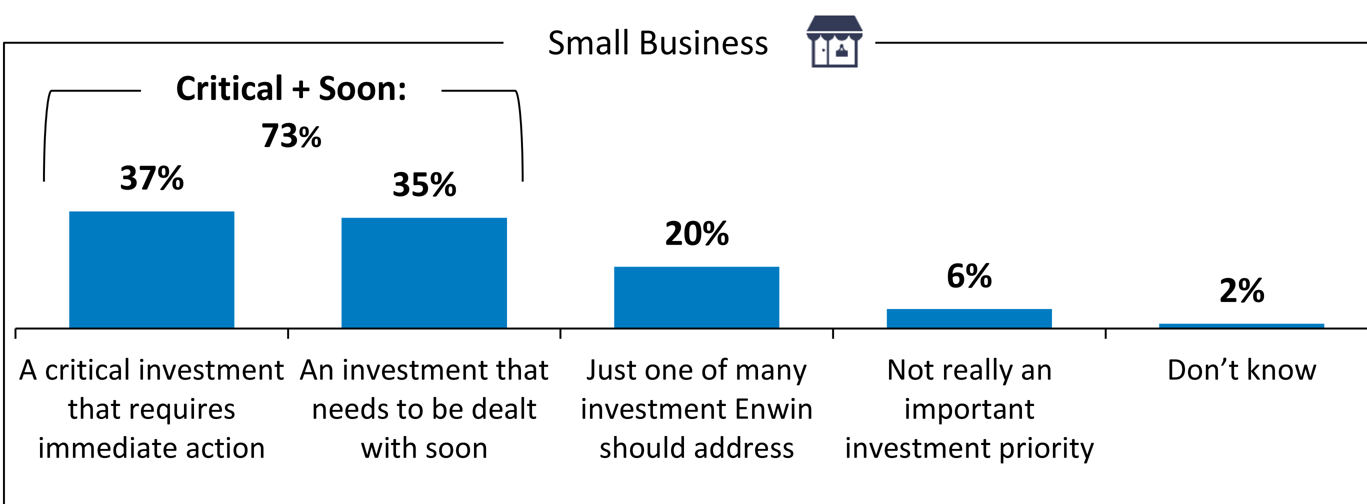
Tornados and flooding can have severe impacts on the electricity distribution grid. A resilient system is one which can bounce back quickly from these disasters.

Given the rise in weather related issues, ENWIN plans to invest in improved outage management systems that will build the resilience of its grid. ENWIN's goal is to provide customers with a consistent level of service, despite weather events and aging infrastructure.

In prior surveys, the majority of customers indicated they felt that investing in maintaining or improving system reliability should be a priority, and that it was important to invest, now, in modernizing the grid.

How important are investments in system reliability and grid modernization?
[asked of all respondents]




Note: sums added before rounding.

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# Urgency of Investments

Residential

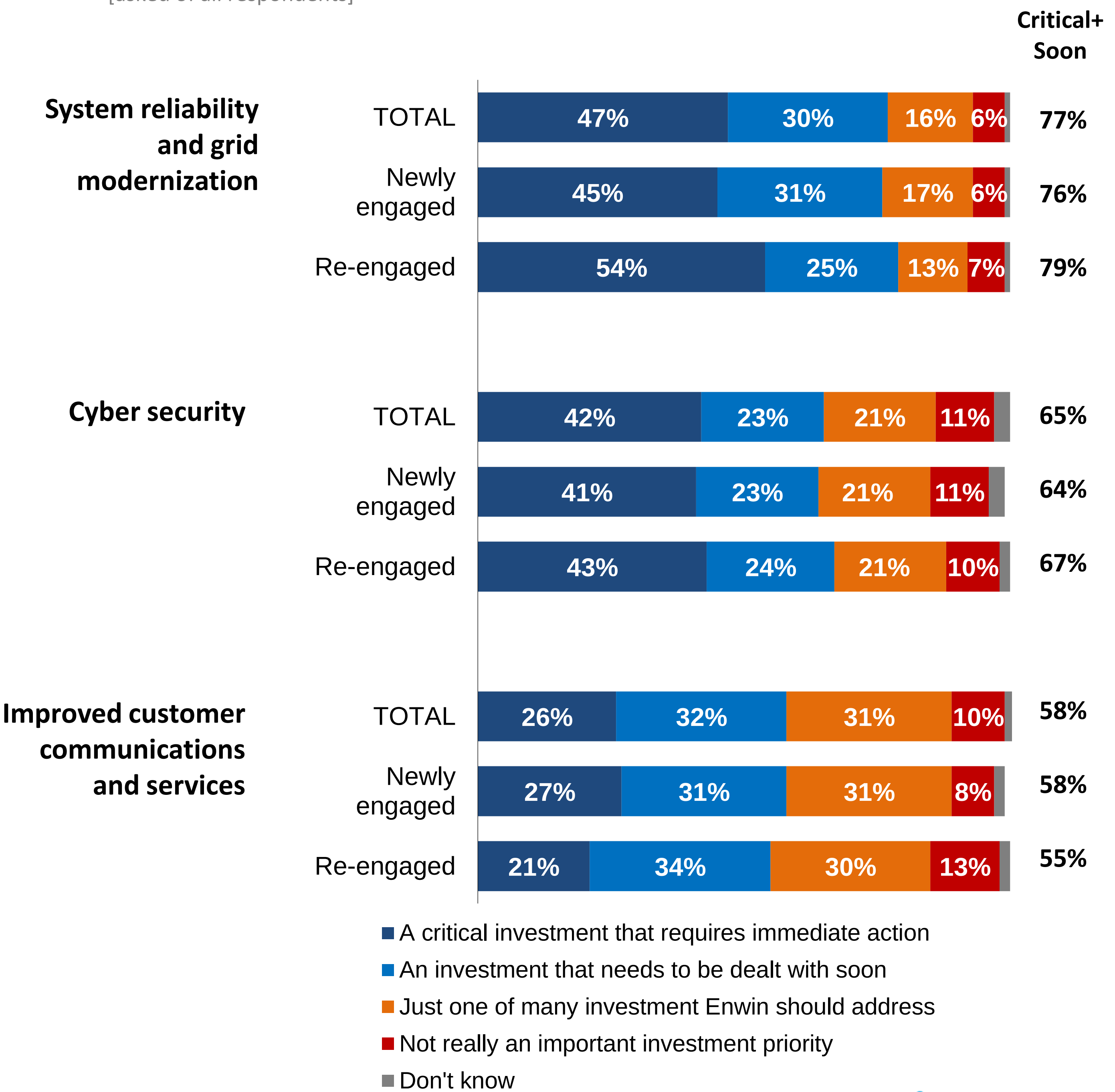
## System reliability/modernization deem more urgent than cyber security and customer communication/service improvements

Q

(See previous slides for question preambles)

How important are investments in …?

[asked of all respondents]

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Note: sums added before rounding.

# Urgency of Investments

Small Business

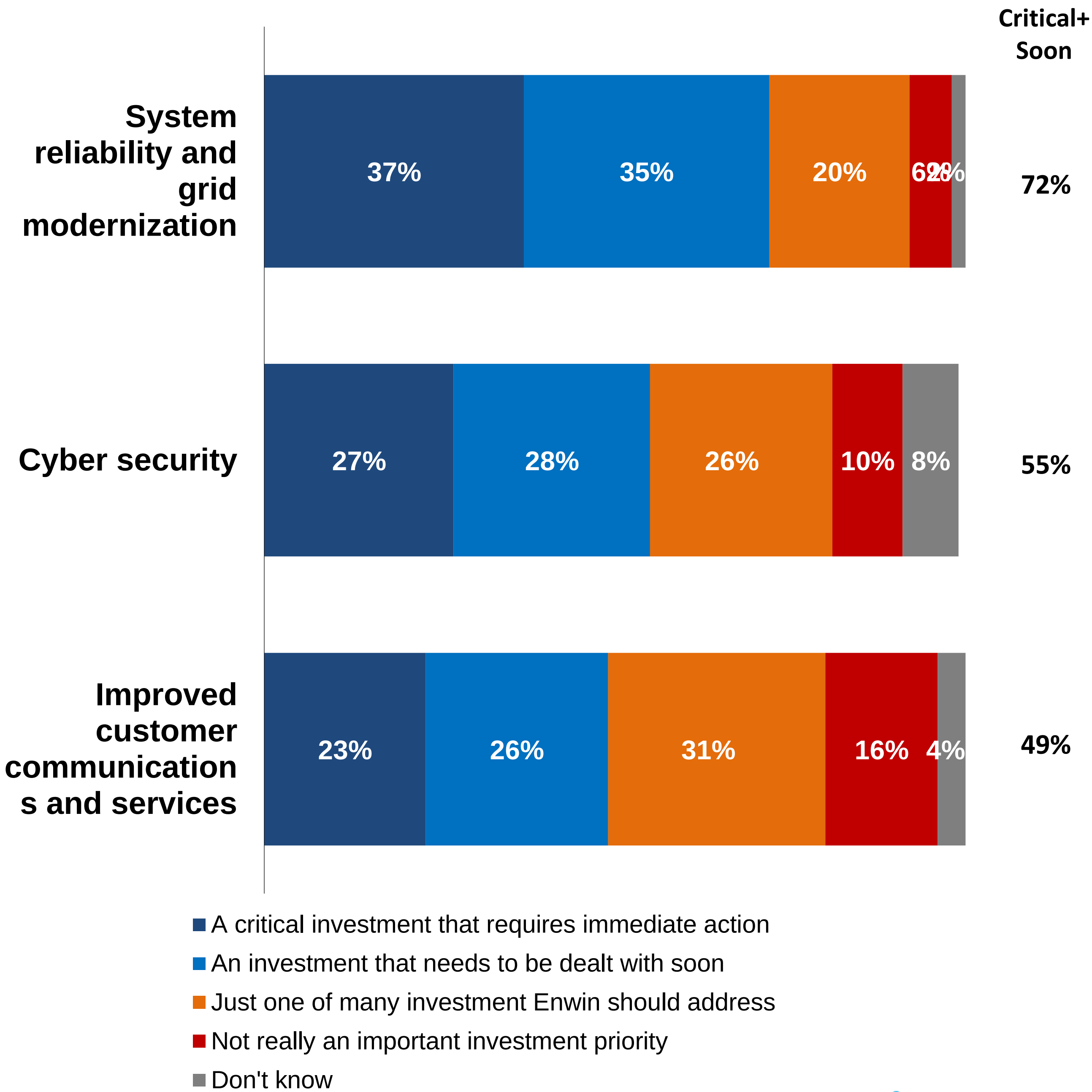
## System reliability/modernization is 17 points ahead of cyber security and 23 pts ahead of customer service improvements

Q

(See previous slides for question preambles)

How important are investments in …?

[asked of all respondents]

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Note: sums added before rounding.

# Cost Impact

# 2017 Customer Consultation Recall

## Most do not recall April 2017 customer consultation

Q

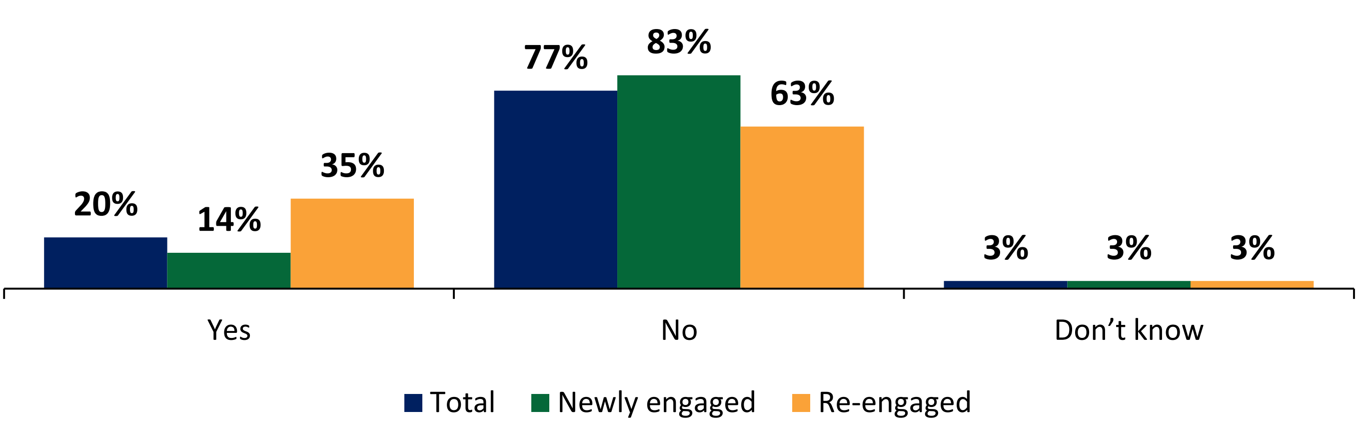
In April 2017 [- when ENWIN last spoke with you -] it was estimated, based on the best available information, that an additional [residential: $1.70 to $3.40 / small business: $3.83 to $7.70] per month would be required of the typical [residential / small business] customer to operate and maintain the ENWIN distribution system in 2019.

It was estimated that by 2023, the typical [residential / small business] customer will be paying [residential: $3.45 to $5.25 / small business: $7.90 to $12.00] per month more on the distribution portion of their electricity bill.

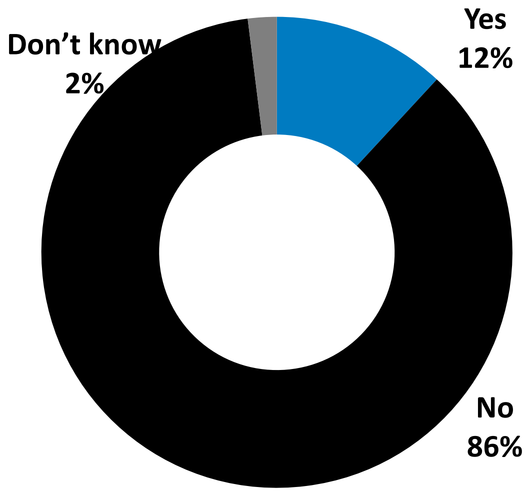
Do you recall reading, hearing or seeing anything about this customer consultation [discussing this rate adjustment when we last spoke in April 2017]?

[asked of all respondents]

Residential




Small Business



# Cost Impact

## Preamble

"*As ENWIN moved through a two-year planning process for this application, the company had to consider how to balance a wide range of customer priorities against the Ontario regulatory requirements and industry best practices. After careful consideration of customer input, electricity sector developments, OEB requirements and global issues related to cyber-security and weather, ENWIN has revised its 2017 draft plan.*

*The new plan recognises what customers told us in 2017 -- that the primary concern for the vast majority of customers is cost. ENWIN's goal through this plan is to balance the needs of all customer groups, and provide for a reliable, resilient distribution system and reduced risk related to global issues.*"

# Social Permission



## Three-quarters give social permission for rate increase; higher among those who consume the least amount of electricity

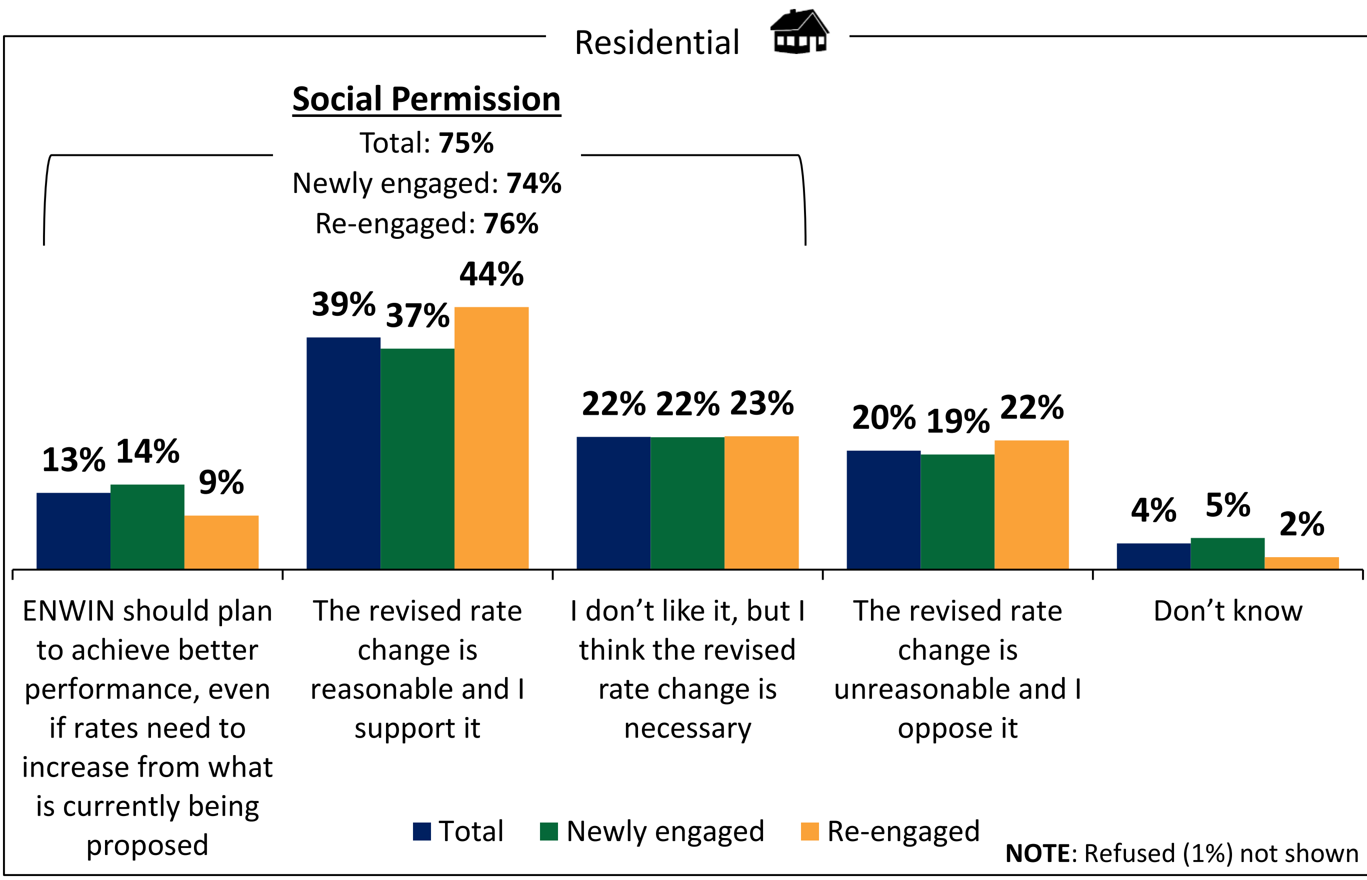
Q

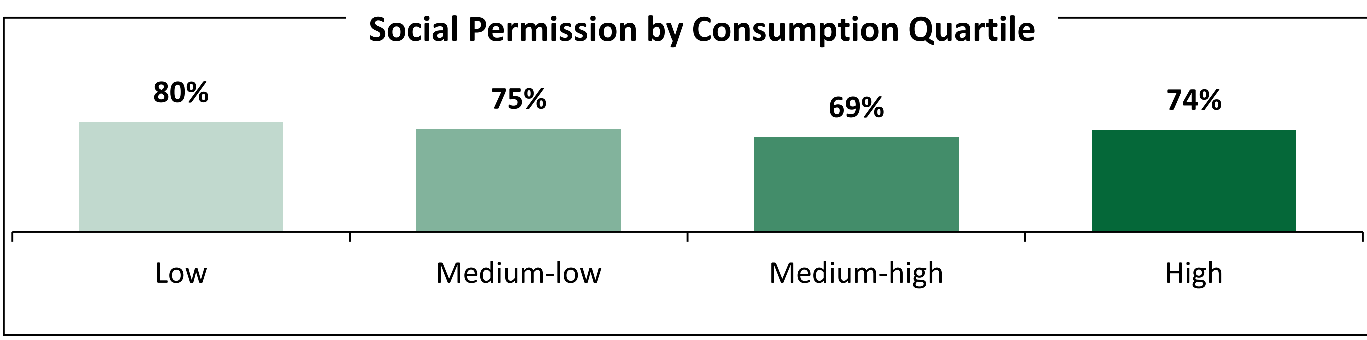
The revised ENWIN plan will cost the typical residential customer $0.04 more per month in 2020 than in 2019. This is about $2.21 less than originally forecasted in April 2017.

By 2023, ENWIN's revised plan indicates that the typical residential customer will be paying an additional $1.29 more per month on the distribution portion of their bill. This is about $2.31 less than originally forecasted back in April 2017.

Considering the cost of ENWIN's revised plan, would you say …?

[asked of all respondents]




Note: sums added before rounding.

# Social Permission



## Two-thirds give social permission for rate increase; higher among lowest consumption small businesses

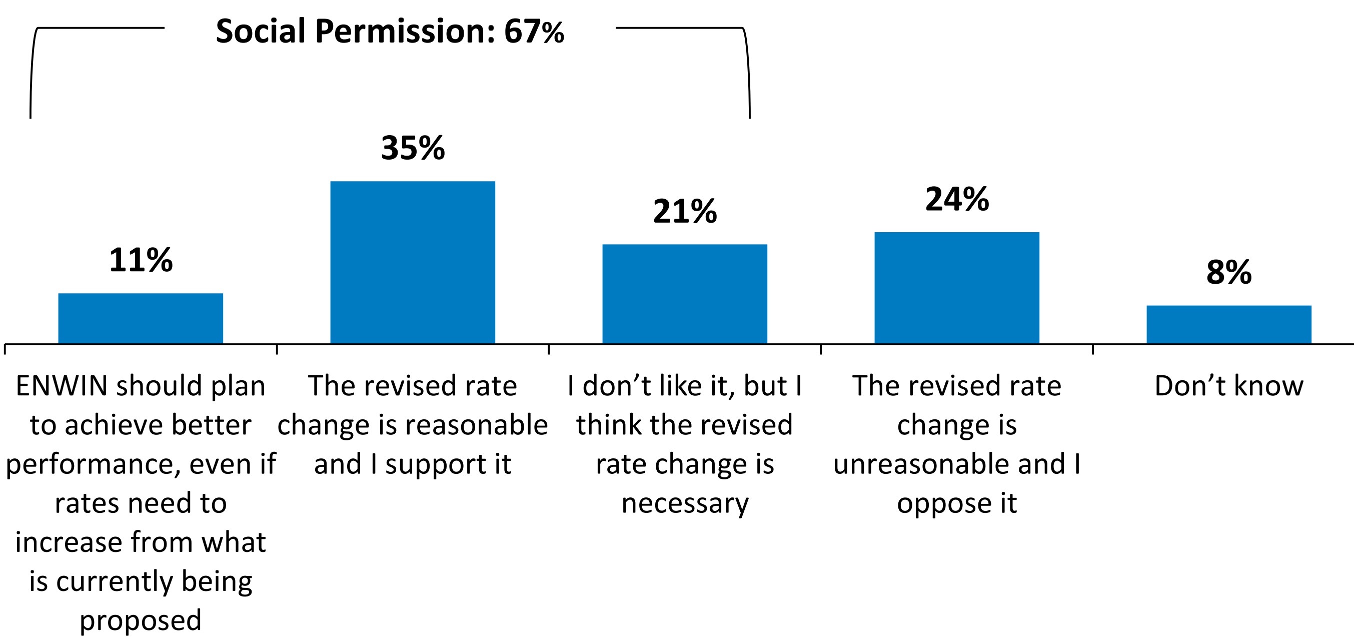
Q

The revised ENWIN plan will cost the typical small business customer $2.69 less per month in 2020 than in 2019. This is about $4.11 less than originally forecasted in April 2017.

By 2023, ENWIN's revised plan indicates that the typical small business customer will be paying an additional $2.98 more per month on the distribution portion of their bill. This is about $4.29 less than originally forecasted back in April 2017.

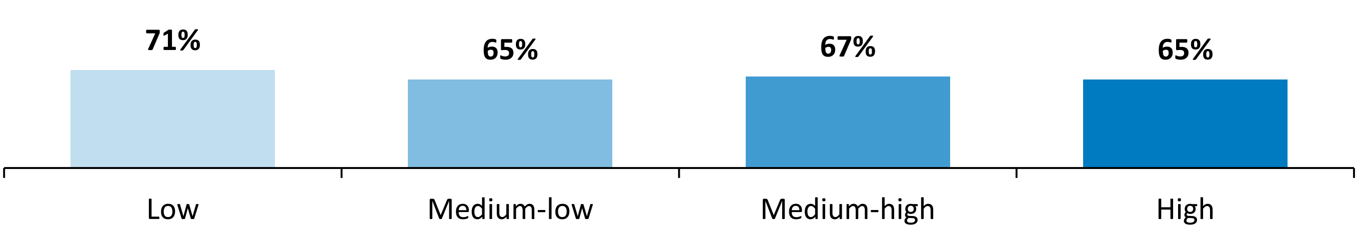
Considering the cost of ENWIN's revised plan, would you say …?
[asked of all respondents]

### Small Business




**NOTE**: Refused (1%) not shown

### Social Permission by Consumption Quartile



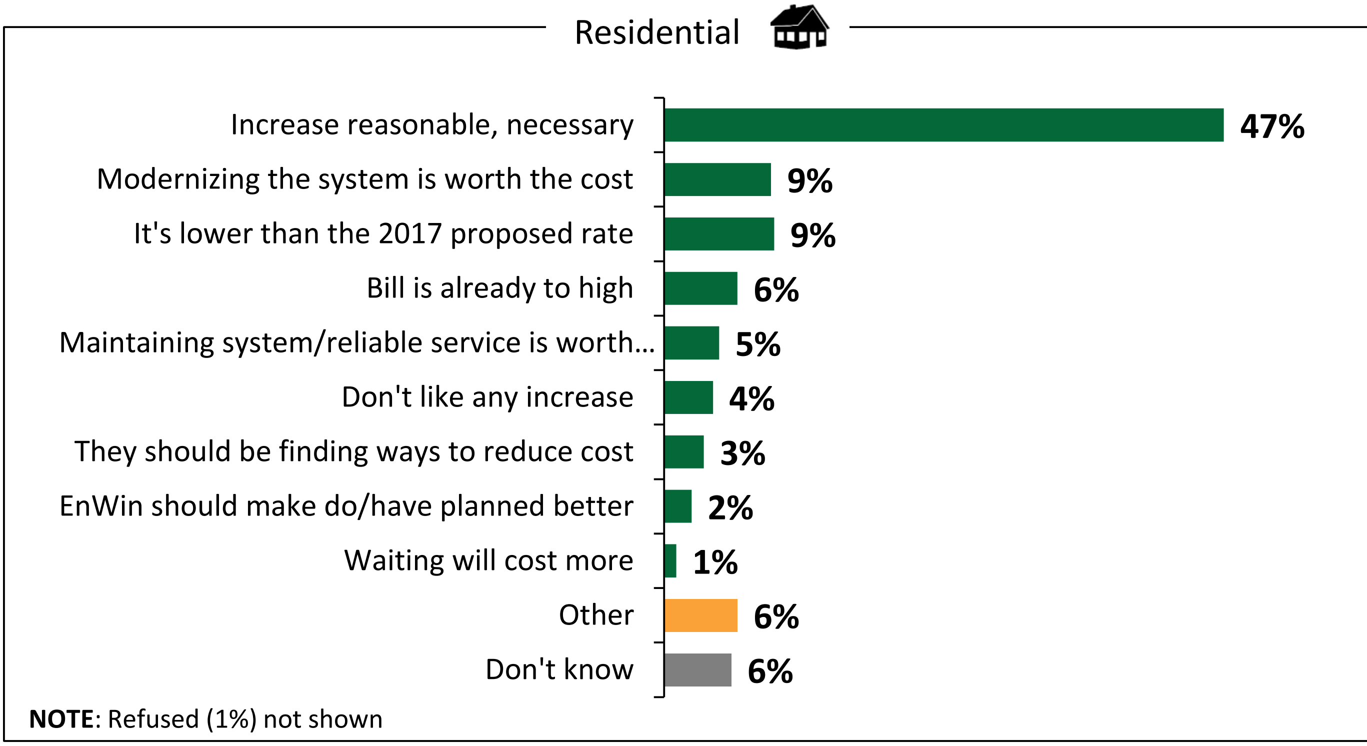

Note: sums added before rounding.

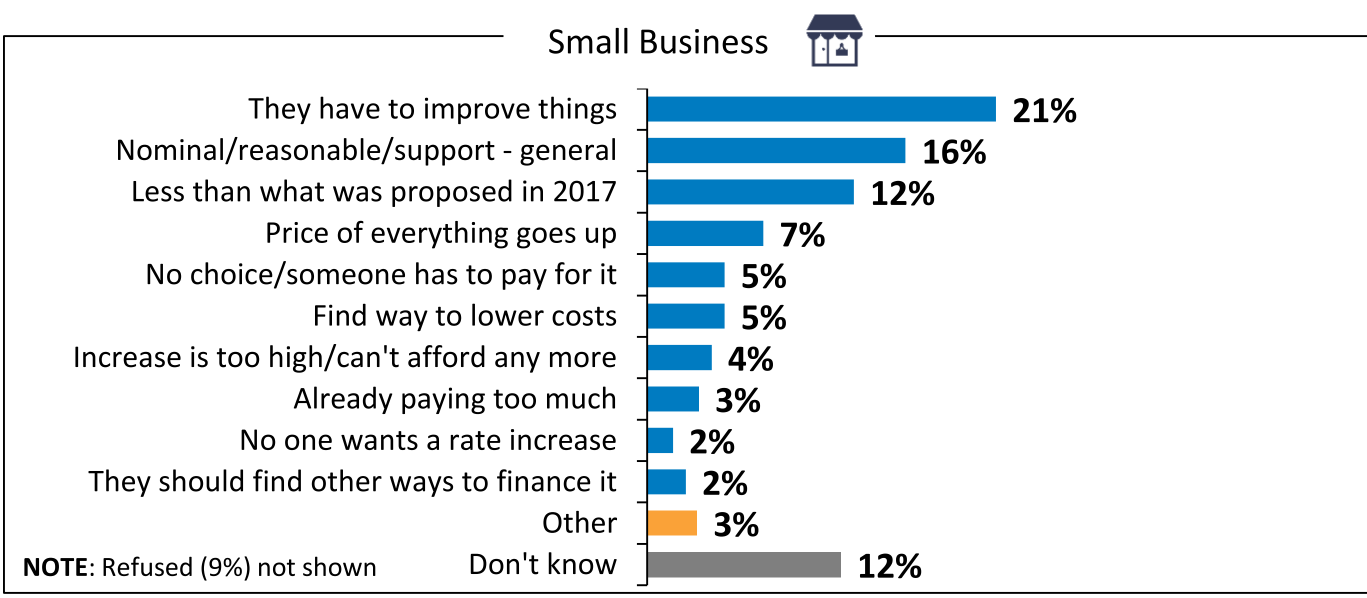
# Reasons for Social Permission

Q

And why do you say that?

[asked of respondents who give social permission for rate increase; residential n=389, small business n=129]

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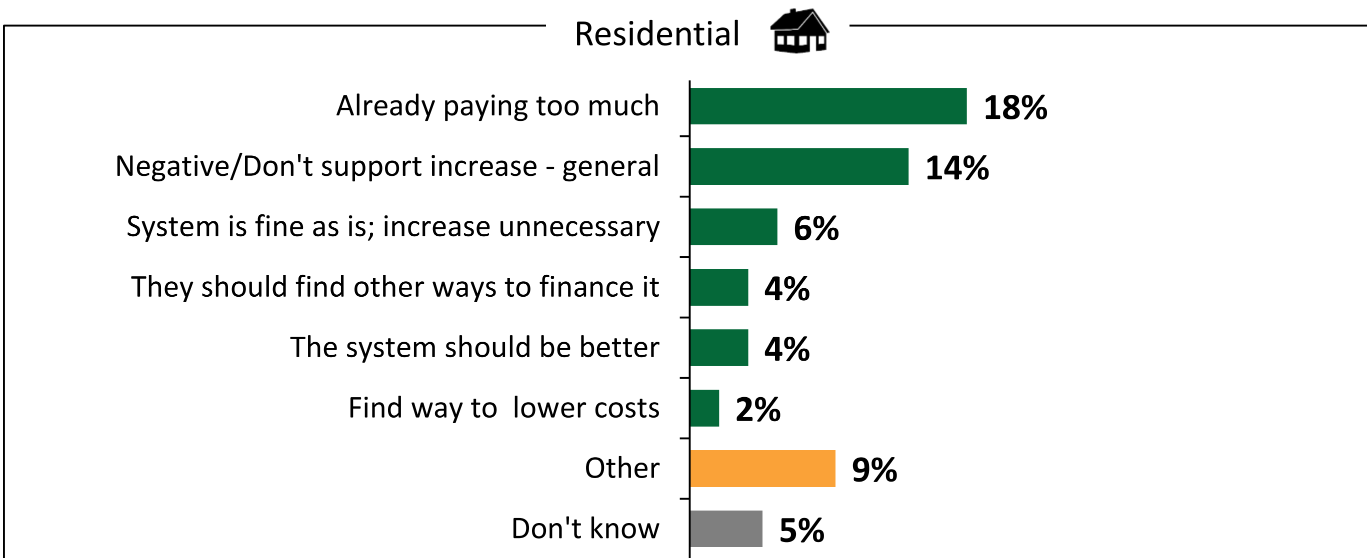
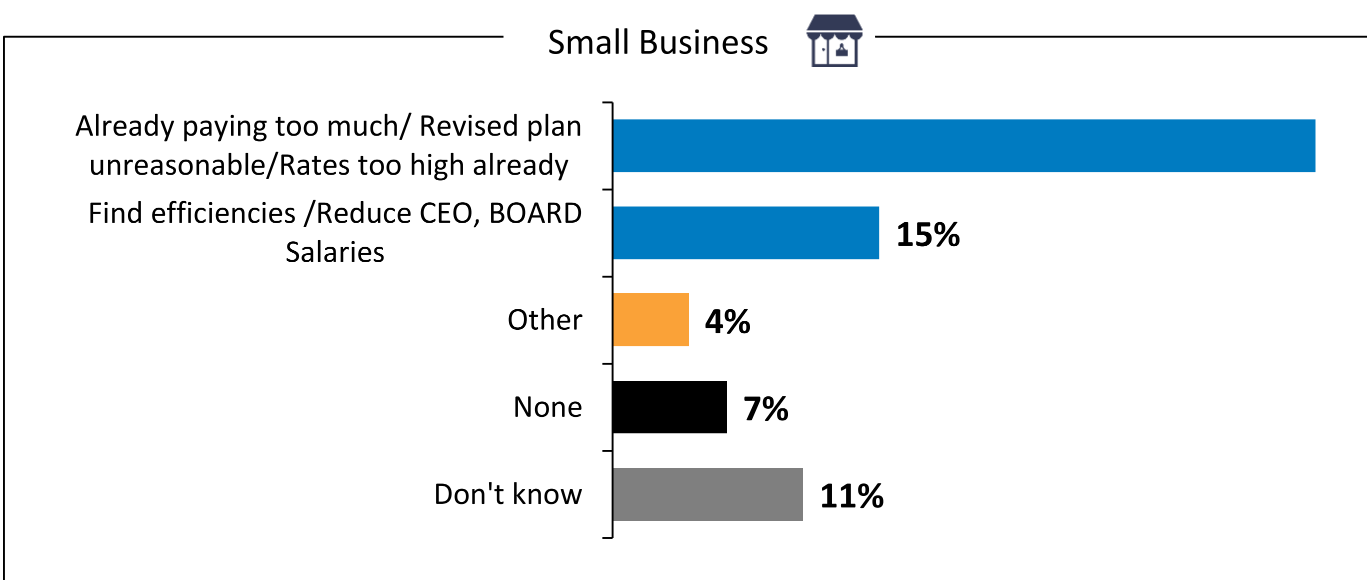
# Reasons for Opposing Increase

Q And what do you find unreasonable about ENWIN's proposed plan?
[asked of respondents who say the revised rate increase is unreasonable; residential n=107, small business n=46]




**NOTE**: Refused (6%) not shown

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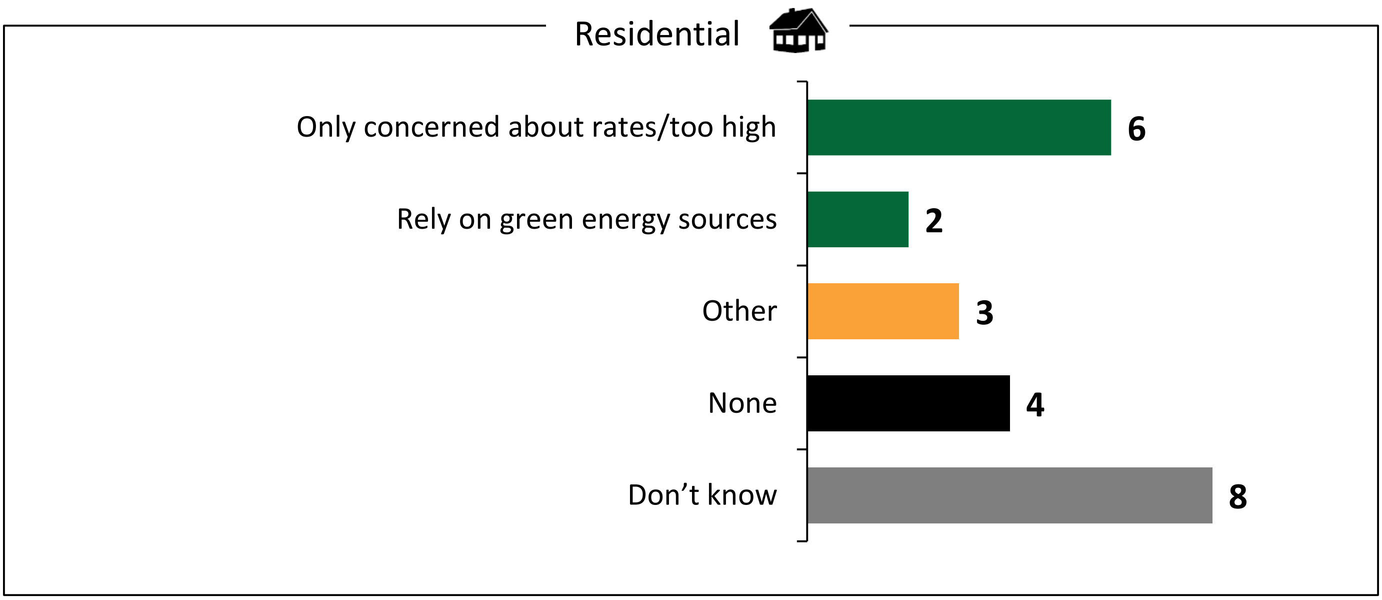
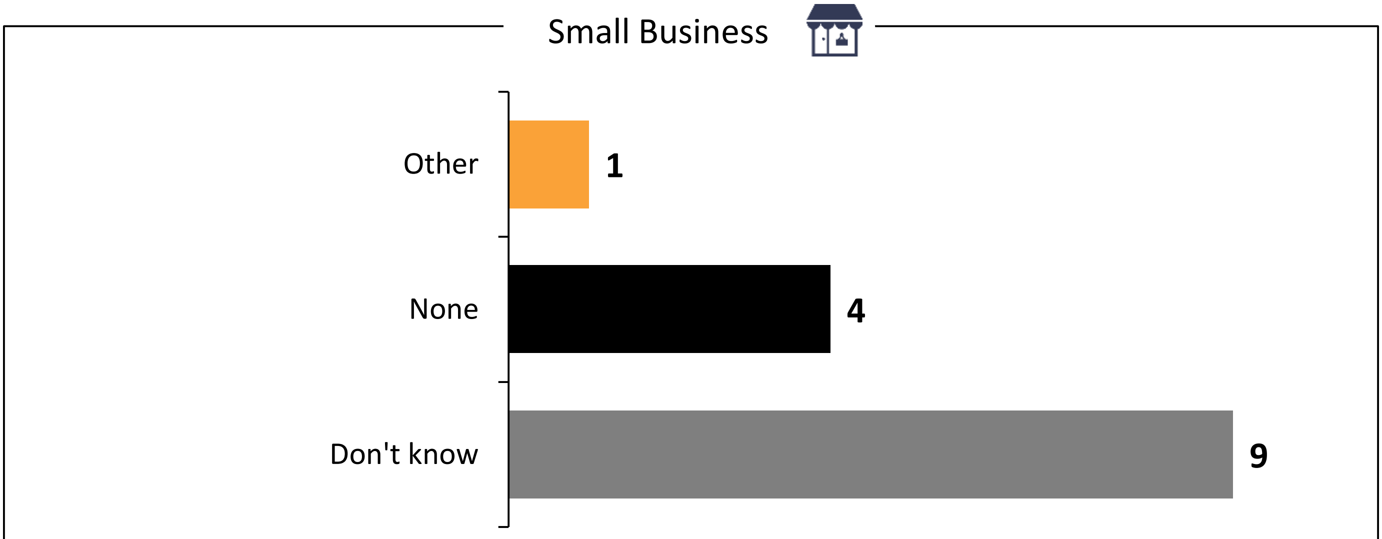
# Outstanding Questions

## CODED RESPONSES

Q

Do you have any outstanding questions about ENWIN's proposed plan?
[asked of respondents who say they "don't know" how they feel about the proposed rate increase; residential n=23, small business n=16]




**NOTE**: Refused (n=2) not shown

# Outstanding Questions

## VERBATIM CUSTOMER COMMENTS

Q Do you have any outstanding questions about ENWIN's proposed plan?
[asked of respondents who say they "don't know" how they feel about the proposed rate increase; residential n=23]

*"Rates go up anyway."*

*"There is enough increase in technology for them not to have to increase the rates. When a barrel of oil costs less than what it costs ten years ago."*

*"What are they are doing green energy source. How they are planning with energy sources and rely less on fossil source."*

*"Why the government cannot give money for this? Why do we pay for this we pay enough taxes."*

**Residential**

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# Building Understanding.

***Personalized research to connect you and your audiences.***

**For more information, please contact:**

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**Julian Garas**
Senior Consultant
(t) 416-640-4133
(e) jgaras@innovativeresearch.ca

## 1 - OEB Staff - 4

Reference:

Exhibit 1, Attachment 1-H

Preamble:

EnWin Utilities provides the 2017 scorecard in the Attachment 1-H.

Question:

a) Please provide the 2018 scorecard and management discussions and analysis.

b) Please provide reasons when the performance measures are not within the minimum standards or not in compliance.

---

Response:

a) and b)

Per the OEB's 2019 Activities Schedule for Publication of the 2018 Scorecard of Electricity Distributors, the 2018 scorecard will not be finalized with all applicable information until August 15. The MD&A is not due to be submitted until September 6, and will then be published by September 30.

Given this timeline, ENWIN's 2018 scorecard is not yet finalized and ENWIN has not yet completed its 2018 MD&A.

## 1 - OEB Staff - 5

Reference:

Exhibit 1, Attachment 1-G, Pages 7 and 8; Exhibit 1, Attachment 1-H

Preamble:

Per the 2018 EnWin Utilities' customer satisfaction survey in the Attachment 1-G, it appears that EnWin Utilities' customers prefer the telephone as a communication method with the utility: the % of EnWin Utilities' customers prefer telephone as a communication method to receive a billing issue and general news are higher than Ontario LDCs. In addition, 43% of EnWin Utilities' customers prefers EnWin Utilities to use telephone to inform an unplanned outage.

Per the 2017 scorecard in Attachment 1-H, the service quality indicator: Telephone Calls Answered on Time has a decreasing performance trend from 82.20% in 2013 to 78.21% in 2017.

Question:

a) Please explain the reasons for the decreased performance in Telephone Calls Answered on Time.

b) Please provide EnWin Utilities' planned processes to improve the performance of this service quality indicator given a significant portion of customers is depending on telephone to communicate with the utility.

c) Please t explain the reasons if the 2018 performance for the Telephone Calls Answered on Time measure that are provided in 1-Staff-4 decreases further as compared to 2017 performance.

---

Response:

a) Call volume and the average ratio of calls received per Customer Service Representative have an impact on ENWIN's year-over-year performance in this metric. However, ENWIN's performance has consistently exceeded the OEB approved target of 65% and ENWIN continues to work hard to answer calls on time while not increasing staff complement.

b) ENWIN has launched a new Customer Portal in 2019 to give customers more self-service options while also improving service levels. ENWIN is also rolling out more proactive communication to help address customer concerns before the need to call. This has reduced call volumes and improved service levels so far in 2019. As of July 1, ENWIN has achieved a service level of 85.3% in 2019 compared to a level of 73.3% last year at this time.

c) ENWIN's 2018 scorecard has not yet been finalized. However, ENWIN's reported Telephone Calls Answered On Time for 2018 was 76.93%, which is indicative of ENWIN's continued strong performance in this area.

## 1 - OEB Staff - 6

Reference:

Exhibit 1, Attachment 1-J EnWin Utilities' 2017 Audited Financial Statements (AFSs)

Preamble:

OEB staff notes that EnWin Utilities' 2017 AFSs has a Note 24 Restatement and comparative figures. Part of the note states that

During the year, the Corporation became aware of certain components within property, plant and equipment that were being calculated incorrectly since the adoption in 2011. Overhead burden rates were too high resulting in assets being overstated and expenses being understated. Also, some depreciation calculations used inappropriate useful lives as a result of componentization which resulted in lower depreciation expenses. As a consequence of the immaterial adjustments, payments in lieu of taxes, property, plant and equipment, deferred taxes, operating expenses and retained earnings were required to recast.

OEB staff notes that the restated 2016 retained earnings decreased by approximately $6 million, the restated 2016 PP&E balance decreased by $7 million, and the restated 2016 net income decreased by $0.8 million.

Question:

a) Please confirm whether or not the reported numbers in the relevant schedules (e.g. PP&E, Account 1575) reflects the restated numbers that match with the restated numbers as at December 31, 2016.

b) Please explain the impacts on the regulated return on equity (ROE) that were reported on the scorecard and provide the revised regulated ROE performance if applicable.

c) Please explain whether or not the 2017 tax return reflected the restated PILs. If not, when does EnWin Utilities plan to report the adjustment?

d) Please provide the correspondence with OEB staff regarding the mistakes and adjustments.

Response:

a) Confirmed - the values included in the Chapter 2 Appendices and relevant schedules and filed in the April 26, 2019 Cost of Service submission did reflect the restated numbers.

b) The restatement in 2017 impacted the property, plant and equipment balances as well as net income. The table below summarizes the originally filed regulated rate of return and the recalculated regulated rate of return with the revised figures:

| Year | RROE - Original Submission | Revised RROE Calculation | Description |
|---|---|---|---|
| **2012** | 3.48% | 1.69% | Regulated net income decreased by $615k; and the average regulated PP&E decreased by $5 million |
| **2013** | 13.04% | 7.66% | Regulated net income decreased by $5.1 million; and the average regulated PP&E decreased by $12.0 million |
| **2014** | 9.62% | 4.46% | Regulated net income decreased by $5.2 million; and the average regulated PP&E decreased by $15.8 million |
| **2015** | 6.88% | 3.43% | Regulated net income decreased by $3.7 million; and the average regulated PP&E decreased by $17 million |
| **2016** | 5.92% | 3.13% | Regulated net income decreased by $3.1 million; and the average regulated PP&E decreased by $15 million |

c) The 2017 PILs return reflected all of the changes embedded within the 2017 audited financial statements.

d) The correspondence with the OEB staff regarding the restatement has been provided in OEB Staff #6 - Attachment 1

# Correspondence

# Dated

# April 19, 2018

**{In Archive} Re: [External] RRR Reporting**
**Byron Thompson** to: Sagar Kancharla 2018-04-19 03:13 PM
Cc: "Ben Bosch", "Mark Rozic", "Stephanie Chan", Matt Carlini
Archive: This message is being viewed in an archive.

Hi Sagar

Further to your email below, please see attached a summary of the adjustments necessary to the 1575 Account as well as a description of the impact of the financial statement recast done in our 2017 financial statements for errors associated with prior year numbers.
At the present time we are preparing the 2.1.7 and other filings for 2017 with the adjustments related to prior years booked to opening retained earnings, leaving the 2017 P&L reflective of 2017 results.
As a result of booking the 1575 account entry this this year (which was not done recently) and other matters, Enwin is below the 300 basis point dead band on its regulated ROI in 2017. ( and would have been last year also).

Once you have had a chance to review the attached file, I would suggest we have a brief call to clarify any questions you or your team might have and then discuss implications and next steps for our RRR filings.

Thanks for your help on this.

Best regards

Byron Thompson
Enwin Utilities Ltd.
519-255-2869

Enwin Account 1575 and restatement impact on RRR 2018 04 19.xlsx

| "Sagar Kancharla" | Hi Byron, Mark Rozic had a discussion with us i... | 04/17/2018 04:12:12 PM |
|---|---|---|

| | |
|---|---|
| From: | "Sagar Kancharla" <Sagar.Kancharla@oeb.ca> |
| To: | "bthompson@enwin.com" <bthompson@enwin.com> |
| Cc: | "Mark Rozic" <Mark.Rozic@oeb.ca>, "Ben Bosch" <Ben.Bosch@oeb.ca>, "Stephanie Chan" <Stephanie.Chan@oeb.ca> |
| Date: | 04/17/2018 04:12 PM |
| Subject: | [External] RRR Reporting |

Hi Byron,
Mark Rozic had a discussion with us in Performance Reporting group about your inquiry to the OEB. To get an understanding of EnWin's accounting and reporting situation and in order to provide you the necessary reporting guidance, we would need more details from you.
On the issue of Account 1575, please provide the actual / estimated annual amounts for each year, applicable adjustments and the total balance as of December 31, 2017 for reporting in the RRR 2.1.7 trial balance. In addition, the regulatory accounting entries for this "catch-up" adjustment(s).
We also understand that there are financial statements restatement(s) involving PP&E (and perhaps others items). For this item, provide the reasons of the restatements, the years restated, the Uniform System of Accounts PP&E accounts, and the "as filed" and "as revised"

amounts for each account. If there are income statement impacts, such as depreciation expense provide these. In addition, the implication these changes will have on the previous regulatory reporting. For example, the extent of any impacts on the previously reported ROEs (RRR 2.1.5.6) as the net income / rate base has changed, and impacts, if any, on previously reported capital additions figures (RRR 2.1.5.2), and the financial reconciliation reporting (RRR 2.1.13).

Please provide this information together with any other relevant information to help us assess the reporting implications.

Thanks

**Sagar Kancharla** | Manager. Licensing & Performance Reporting
Consumer Protection & Industry Performance | Ontario Energy Board
2300 Yonge Street, 27th Floor |Toronto, ON | M4P 1E4 | Ph: 416 440 7602

ONTARIO ENERGY BOARD | COMMISSION DE L'ÉNERGIE DE L'ONTARIO

**ENWIN Utilities Ltd**
**Summary of Restated Property, Plant and Equipment & Regulatory liabilities**
**as at December 31, 2017**

**Issue 1: 1575 Catch up**

Upon inspection of the regulatory liability accounts it was noted that annual adjustments to the 1575 account were not made since the initial entry in 2012. Taking into account the adjustments noted below related to depreciation and burden, the balance that should have been recorded in account 1575 and what was previously report are sumaried below:

| account: 1575 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| as reported: | (10,530,352) | (10,530,352) | (10,530,352) | (10,530,352) | (10,567,390) | (10,567,390) |
| revised: | (7,771,542) | (10,369,050) | (12,634,876) | (14,569,146) | (16,940,510) | (19,220,838) |
| Difference - reported vs revised | 2,758,810 | 161,302 | (2,104,524) | (4,038,794) | (6,373,120) | (8,653,448) |
| Annual P&L impact | | (2,597,508) | (2,265,826) | (1,934,270) | (2,371,364) | (2,280,328) |

For purposes of reporting this year, the entry below was booked record the entry.

| | | | | | |
|---|---|---|---|---|---|
| Journal entry: | Dr | 4310 | Regulatory Credits | 2,280,328 | |
| | Dr | 3045 | Retained earnings | 6,373,120 | |
| | Cr | 1575 | IFRS CGAAP Transitional Account | | 8,653,448 |

**Issue 2: Financial Statement Restatement with Impacts to 2.1.7**

**In preparation of the current year financial statements Enwin management discovered errors dating back to the 2012 conversion to IFRS. In Enwin's 2017 audited financial statements, a recast (restatement) of prior year numbers was done to correct these errors.**

There were generally two types of errors identified and restated. A description of the error and $ amount of adjustment made on account of each year are provided below:

***a) Burden rates were incorrect***

*ENWIN* s burden rates were overstated as a result of errors. Specifically, non direct management was included in the calculation and mathematical errors were also embedded in the calculation of the burden rate that was applied to capital labour. These results of these errors was an understatement of O&M expenses and overstatement of PP&E.

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| Over capitalization | (780,721) | (639,896) | (826,821) | (1,019,465) | (762,269) | (745,711) | (825,488) |
| Cumulative impact | | | | | | (4,774,883) | |

Similair to how the entry was proposed above for account 1575, the entry below was booked in 2017 to correct this error.

| | | | | | |
|---|---|---|---|---|---|
| Journal entry | Dr | 5005-5175 | O&M expense | 825,488 | |
| | Dr | 3045 | Retained earnings | 4,774,883 | |
| | Cr | 1830 | Property, Plant and Equipment | | 5,600,371 |

***b) Componentization and Mathematical Errors calculating Depreciation***

Componentization errors caused the wrong useful lives to be used to calculate depreciation expenses. Specifically, transformer useful lives should have been 35 or 40 years consistent with the Kinetrics report but instead the power transformer category was selected with a useful life of 45 years.
Enwin had failed to componetize its transformers and included all submerible, pad mounted and pole mounted transformers in one category, utilizing the power transformer useful life. That resulted in an understatement of depreciation expenses.
Additionally Some mathematical / clerical errors were also identified during the review of our subledger which resulted in the wrong remaining useful life being applied to a number of assets. That also resulted in depreciation expense being understated.
- Depreciation was also impacted by the burden rate adjustements noted above.

The chart below summarizes the understatement of depreciation that occurred in each year (or the increase that was booked to correct it) The amounts below are net of the offsetting impact of utilization of lower burden rates as described in (a) above.

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| Understated Depreciation | (469,358) | (452,845) | (427,828) | (412,060) | (394,896) | (370,520) | (344,751) |

| | | | | | |
|---|---|---|---|---|---|
| Journal entry | Dr | 5,705 | Depreciation expense | 344,751 | |
| | Dr | 3,045 | Retained earnings | 2,527,507 | |
| | Cr | 2,105 | Accumulated Depreciation | | 2,872,258 |

***c) Tax adjustments as a result of the adjustments above.***

| | 2,011 | 2,012 | 2,013 | 2,014 | 2,015 | 2,016 | 2,017 |
|---|---|---|---|---|---|---|---|
| Reduction to tax expense | | | | 270,158 | 202,001 | 197,613 | 218,754 |

| | 2,011 | 2,012 | 2,013 | 2,014 | 2,015 | 2,016 | 2,017 |
|---|---|---|---|---|---|---|---|
| Reduction to deferred tax | 124,380 | 120,004 | 113,375 | 109,196 | 104,648 | 98,188 | 91,359 |

**ENWIN Utilities Ltd**
**Summary of Restated Property, Plant and Equipment & Regulatory liabilities**
**as at December 31, 2017**

| | | | | | |
|---|---|---|---|---|---|
| Journal entry: | Dr | 1,110 | PILs receivable | 888,527 | |
| | Cr | 3,045 | Retained earnings | | 669,773 |
| | Cr | 6,110 | Income tax expense | | 218,754 |
| | Dr | 1,495 | Future PILs receivable | 761,148 | |
| | Cr | 3,045 | Retained earnings | | 669,789 |
| | Cr | 2,320 | Future PILs liability | | 91,359 |

**Total**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Change to regulatory Net income (reduction) | 1,666,069 | (3,852,158) | (3,427,193) | (2,889,434) | (3,289,981) | (3,231,813) |

( includes 1575 but
excludes deferred tax )

**Impacts on RRR :**

2.1.5 Capital - A) Gross Capital additions

| | MIFRS 2012 | MIFRS 2013 | MIFRS 2014 | MIFRS 2015 | MIFRS 2016 | MIFRS 2017 |
|---|---|---|---|---|---|---|
| as filed: | 17,468,716 | 20,091,775 | 19,920,856 | 22,631,448 | 18,697,650 | |
| revised: | 16,828,820 | 19,264,954 | 18,901,391 | 21,869,179 | 17,951,939 | 15,854,524 |

2.1.5 Capital - B) Capitalized overhead

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| as filed: | 1,803,642 | 2,246,126 | 2,497,727 | 2,280,423 | 2,184,126 | |
| revised: | 1,163,746 | 1,419,304 | 1,478,263 | 1,518,154 | 1,438,415 | 1,303,826 |

2.1.5.6 Regulated ROE

A full review of the restated regulated ROE has not been completed due to the time constraints.
Regulatory net income would be reduced by "Change to regulatory Net income" as noted above.
The result in 2017 is that the Regulated ROE is below the 300 basis point dead band.

# Correspondence

# Dated

# April 24 – May 22, 2018

{In Archive} RE: [External] RE: Follow up
Sagar Kancharla
to:
Byron Thompson
2018-05-22 05:05 PM
Cc:
"Ben Bosch", "Matt Carlini", "Paul Gleason"
Hide Details
From: "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>
To: "Byron Thompson" <bthompson@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>, "Matt Carlini" <mcarlini@enwin.com>, "Paul Gleason" <pgleason@enwin.com>
Archive: This message is being viewed in an archive.

Thanks Byron.
Look forward to meeting you and your team.

Sagar

**From:** Byron Thompson <bthompson@enwin.com>
**Sent:** Tuesday, May 22, 2018 2:17 PM
**To:** Sagar Kancharla <Sagar.Kancharla@oeb.ca>
**Cc:** Antonette Franco <Antonette.Franco@oeb.ca>; Ben Bosch <Ben.Bosch@oeb.ca>; Matt Carlini <mcarlini@enwin.com>; Paul Gleason <pgleason@enwin.com>
**Subject:** Re: [External] RE: Follow up

Hi Sagar

We have prepared a summary of the impact of the changes by year and the related ROI recalculation as requested and attached.

See you tomorrow.

Byron Thompson
Enwin Utilities Ltd.
519-255-2869

From: "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>
To: "Byron Thompson" <bthompson@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>, "Paul Gleason" <pgleason@enwin.com>, "Matt Carlini" <mcarlini@enwin.com>, "Antonette Franco" <Antonette.Franco@oeb.ca>
Date: 05/10/2018 03:28 PM
Subject: Re: [External] RE: Follow up

---

Hi Byron

May 23rd will work for us. Can we make it 10am start.

Regards
Sagar

Sent from my iPhone

On May 10, 2018, at 10:58 AM, Byron Thompson <bthompson@enwin.com> wrote:

Good morning Sagar

We are presently looking at travel to Toronto the week after Victoria Day, and wondered if the morning of Wednesday May 23rd would work for a meeting.  We can accommodate any time that morning.

Best regards

Byron Thompson
Enwin Utilities Ltd.
519-255-2869

From: "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>
To: "Byron Thompson" <bthompson@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>
Date: 05/07/2018 09:58 AM
Subject: RE: [External] RE: Follow up

---

Thanks Byron for clarifying our questions.
We had a quick look at your recent RRR submissions as well.

I do not have any context to "specified procedure" discussions, but I will speak to Ted and Dan about this.

You mentioned that you are likely to be here in Toronto. Is it possible to firm up a date and at that meeting we can complete the discussions on next steps?

Regards
Sagar

**From:** Byron Thompson <bthompson@enwin.com>
**Sent:** Wednesday, May 2, 2018 6:18 PM
**To:** Sagar Kancharla <Sagar.Kancharla@oeb.ca>
**Cc:** Ben Bosch <Ben.Bosch@oeb.ca>
**Subject:** RE: [External] RE: Follow up

Hi Sagar,

As per our communication, we have filed the 2017 RRR as previously proposed. Thanks for your comments on the 27th of April.

Further to your questions below please see the following comments to your questions:

Question 1. Could you provide us with the ROE calculations for all the years impacted? You could utilize the spreadsheet templates that you use for the ROE submissions.

Reply 1 We will continue to work through the ROE calculations for the prior years, and I will approach using the spreadsheets as you have suggested for the most recent years. After which I will send to you to discuss next steps.

2. Are there any documents of the reviews by your auditors that you are able to share with us?

Reply 2 I am not sure what you are looking for here. I will provide some back ground on our audit situation in response and please see the response to the 4th question below also. Enwin converted to IFRS in 2012. At that time, regulatory assets and liabilities were not permitted under IFRS and accordingly the accounts are not audited as part of the regular financial statement audit. The PP&E accounts on an IFRS basis will naturally have been audited as part of the annual Enwin financial statement audit. Hopefully the response to question 4 will provide the ultimate reply in this regard.

3. I understand that Enwin has breached the 300bps thresh-hold at least for 2017. I need to discuss with the Rates team here, if Enwin needs to come in earlier than 2020 with COS rate application. For now, can you inform us, if Enwin can pull together an application for 2019 rate application if required? Does Enwin fall under the Jan cycle or May cycle of rate applications?

Reply 3. Enwin is currently on the May cycle. Enwin has been working on preparation of a COS application and had been internally targeting a January 1, 2020 application. Enwin is not currently on the OEB's 2019 of COS filers. Management expects it would not be able to file a May 2019 COS application by August 31, 2018, but might be able to file such an application by November or December 2018. We were uncertain if this would even be an option in terms of the OEB's capacity for 2019 COS applications and the timeliness of such a filing.

4. In your voicemail, you mentioned about engaging KPMG to review the adjustments and the controls/processes being put in place. Is it possible to understand the scope of the engagement and the potential dates of completion for this engagement?

Reply 4. We have approached KPMG and discussed a possible audit opinion on our regulatory assets and liabilities, as well as a possible report on conducting specified procedures. KPMG indicated they have had this discussion with OEB staff in the past, and did not get approval from the OEB on the "specified procedure" approach and accordingly we were planning to have them in to audit our 2017 group 1 and group 2 accounts. I understand these discussions where with Ted Anthonopoulos and Dan Gapic. Last Friday we discussed possible dates with KPMG for this work including late May and June. We would hope to have this work done by some time in July. Enwin would envision sharing this report with the OEB and would be happy to receive any input on the nature of work to be performed.

Further to the above comments, please advise when we can have a call to discuss these matters so that we can move these important matters forward. I will be in Toronto at some time over the next few weeks with our regulatory manager. Possibly at that time we might be able to meet briefly if that would help us keep moving this forward also,

Talk soon and best regards.

Byron Thompson
Enwin Utilities Ltd.
519-255-2869

From: "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>
To: "Byron Thompson" <bthompson@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>
Date: 04/27/2018 02:14 PM
Subject: RE: [External] RE: Follow up

---

Hi Byron,

Thanks for all the information provided through this email and the voicemail.
We have reviewed the information and we are in general agreement of the approach you have taken for the adjustments. Since the RRR filing date is approaching, we would like to have a look at the submissions and follow-up with any questions/clarifications that we might have.
Meanwhile, appreciate if you could respond/clarify some questions:

1. Could you provide us with the ROE calculations for all the years impacted? You could utilize the spreadsheet templates that you use for the ROE submissions.
2. Are there any documents of the reviews by your auditors that you are able to share with us?
3. I understand that Enwin has breached the 300bps thresh-hold at least for 2017. I need to discuss with the Rates team here, if Enwin needs to come in earlier than 2020 with COS rate application. For now, can you inform us, if Enwin can pull together an application for 2019 rate application if required? Does Enwin fall under the Jan cycle or May cycle of rate applications?
4. In your voicemail, you mentioned about engaging KPMG to review the adjustments and the controls/processes being put in place. Is it possible to understand the scope of the engagement and the potential dates of completion for this engagement?

Regards

**Sagar Kancharla** | Manager. Licensing & Performance Reporting
Consumer Protection & Industry Performance | Ontario Energy Board
2300 Yonge Street, 27th Floor |Toronto, ON | M4P 1E4 | Ph: 416 440 7602
<mime-attachment.png>

**From:** Byron Thompson <bthompson@enwin.com>
**Sent:** Friday, April 27, 2018 7:57 AM
**To:** Sagar Kancharla <Sagar.Kancharla@oeb.ca>
**Subject:** Re: [External] RE: Follow up

Hi Sagar

Just following up again. I realize this is a very busy time for you. Given the pending deadline we are presently populating your system with our numbers as I provided you last week which essentially records prior year portion of adjustments to retained earnings, and the current year adjustment to 1575 , etc in the current P&L. It was our thought this allows 2017 operations to be viewed on a correct basis.

Ultimately if you and your staff would prefer a different approach or updates to other years we would be happy work with you on this. When you have a chance please let me know when we can discuss.

Best regards

Byron Thompson
Enwin Utilities Ltd.
519-255-2869

From: "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>
To: "Byron Thompson" <bthompson@enwin.com>
Date: 04/24/2018 11:42 AM
Subject: [External] RE: Follow up

---

Hi Byron

Thanks for the information. I am getting together with my team tomorrow to discuss the material you have sent.
I will get back to you later this week if we need any clarifications.

Regards
Sagar

-----Original Message-----
From: Byron Thompson <bthompson@enwin.com>
Sent: Tuesday, April 24, 2018 9:38 AM
To: Sagar Kancharla <Sagar.Kancharla@oeb.ca>
Subject: Follow up

Good morning Sagar

Just wondering if you had a chance to review the information sent last week, and if you might be available for a call later today or tomorrow afternoon to discuss the material sent and our approach in the RRR.

Best regards

Byron Thompson
519-566-7870

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Enwin Utilities Ltd
Adjustments to Regulated Net Income and ROI
Based 2017 Year End Adjustments for Burden, Depreciation and Account 1575

| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| **Regulated Net Income - as reported** | a | | 6,601,023 | 15,808,168 | 14,037,539 | 12,807,585 | 12,398,320 | 7,239,720 |
| **Adjustments** | | | | | | | | |
| Rerverse 1575 / 4310 | | | 6,043,626 | | | | | |
| Corrected 1575 / 4305 /4310 | | | (4,389,506) | (2,597,508) | (2,265,827) | (1,934,269) | (2,371,364) | (2,280,328) |
| Adjustment for Burdens | | (780,721) | (639,896) | (826,821) | (1,019,465) | (762,269) | (745,711) | (825,488) |
| Tax impact of Burden adjustment | | | 0 | 0 | 270,158 | 202,001 | 197,613 | 218,754 |
| Adjustment for Depreciation | | (469,358) | (452,845) | (427,828) | (412,060) | (394,896) | (370,520) | (344,751) |
| Total Adjustments | b | | 561,378 | (3,852,157) | (3,427,193) | (2,889,433) | (3,289,981) | (3,231,813) |
| **Regulated Net Income - as corrected** | c = a+b | | 7,162,402 | 11,956,011 | 10,610,345 | 9,918,151 | 9,108,338 | 4,007,907 |
| **Adjustments for Regulated Return Calculations , not included in earlier ROE Schedules** | | | | | | | | |
| Remove non utility accounts 4375/4380 | d | | (2,217,711) | (1,145,597) | (1,383,098) | (1,727,076) | (1,114,832) | (1,027,413) |
| Total Adjustments for Regulated ROI recalculations | b +d | | (1,656,333) | (4,997,754) | (4,810,291) | (4,616,510) | (4,404,813) | (4,259,225) |
| Regulated Net Income for RROI , excluding non reg | | | 4,944,691 | 10,810,414 | 9,227,247 | 8,191,075 | 7,993,507 | 2,980,494 |
| Regulatory Return on Net Income - Reported | | | 3.48% | 13.04% | 9.62% | 6.88% | 5.92% | 2.50% |
| Regulatory Return on Net Income - Recalculated | | | 1.81% | 8.24% | 5.37% | 4.03% | 3.64% | 2.50% |

**Account 1575 IFRS/CGAAP Transitinal Amounts - As restated in 2018**

| **As Recast** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|---|---|
| PP&E Values under CGAAP | | | | | | | |
| Opening net PP&E | 179,295,701 | 176,254,689 | 174,929,663 | 173,054,149 | 191,207,789 | 195,208,433 | 196,803,074 |
| Net Additions | 10,378,061 | 13,676,738 | 11,820,684 | 36,299,516 | 20,656,341 | 18,701,286 | 15,425,838 |
| Net Depreciation | (13,419,073) | (15,001,764) | (13,696,198) | (18,145,876) | (16,655,697) | (17,106,644) | (17,640,587) |
| Closing net PP&E CGAAP | 176,254,689 | 174,929,663 | 173,054,149 | 191,207,789 | 195,208,433 | 196,803,074 | 194,588,325 |
| PP&E Values under MIFRS | | | | | | | |
| Opening net PP&E | 179,295,701 | 179,636,724 | 182,701,205 | 183,423,198 | 203,842,665 | 209,777,578 | 213,743,584 |
| Net Additions | 10,260,981 | 11,592,871 | 9,631,583 | 33,774,429 | 17,671,696 | 16,334,278 | 13,043,119 |
| Net Depreciation | (9,919,958) | (8,528,390) | (8,909,589) | (13,354,962) | (11,736,783) | (12,368,273) | (12,977,541) |
| Closing net PP&E -MIFRS | 179,636,724 | 182,701,205 | 183,423,198 | 203,842,665 | 209,777,578 | 213,743,584 | 213,809,162 |
| Difference in Closing net PP&E, former CGAAP vs. revised CGAAP | (3,382,035) | (7,771,542) | (10,369,050) | (12,634,876) | (14,569,146) | (16,940,510) | **(19,220,838)** |
| Annual Difference | (3,382,035) | (4,389,506) | (2,597,508) | (2,265,827) | (1,934,269) | (2,371,364) | (2,280,328) |

**As Previously Reported**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Difference in Closing net PP&E, former CGAAP vs. revised CGAAP | 4,632,114 | 10,530,352 | 10,530,352 | 10,530,352 | 10,530,352 | 10,530,352 | 10,530,352 |

# Correspondence

# Dated

# July 26, 2018

**Enwin letter on Regulatory Reporting**

Byron Thompson to: Sagar Kancharla, Tony.Stanco, Ben.Bosch, stephanie.chan 2018-07-26 06:42 PM

Cc: Helga Reidel, Paul Gleason, Matt Carlini

Good afternoon Sagar

Please see attached a letter summarizing recent work associated with Enwin's regulatory reporting and financial statements.

Thank you and your staff for your help on this matter. If there are any questions or concerns please do not hesitate to contact me directly.

Best regards

Byron Thompson CPA, CA
CFO and VP Finance
Enwin Utilities Ltd.
519-255-2869

Enwin Ltr to OEB 2017 RRR and Financial statements 2018 07 26.pdf

July 26, 2018

Sagar Kancharla
Manager Licensing & Performance Reporting
Ontario Energy Board
2300 Younge Street, 27th Floor
Toronto ON M4P 1E4

Dear Mr Kancharla:

Re: RRR reporting follow-up

On April 19, 2018, ENWIN Utilities Ltd. (ENWIN) contacted OEB Staff to provide further details of various self-identified and self-reported adjustments that were required to Account 1575 as well as changes to the ENWIN 2017 Financial Statements to account for errors uncovered by ENWIN's new management team associated with RRR reporting between 2011-2017.

In that correspondence, ENWIN quantified the four (4) corrections that management had identified as being required:

a. **Account 1575 Catch-up.** Upon inspection of ENWIN's regulatory liability accounts it was noted that annual adjustments to the 1575 account were not made since the initial entry in 2012. Since ENWIN completely converted to IFRS in 2012, and since regulatory assets and liabilities were not permitted under IFRS – these accounts were not included as part of ENWIN's regular financial statement audits. The correction resulted in an amount of $8,653,448 being credited to account 1575 in 2017.
b. **Burden Rates.** In preparing its current year financial statement, ENWIN management discovered that its burden rates were overstated due to non-direct management being included in the calculation, and in addition mathematical errors were also embedded in the burden rate that was applied to capital labour dating back to the 2012 conversion of IFRS, which resulted in an understatement of O&M expenses and overstatement of PP&E. The correction resulted in an amount of $5,600,371 being credited to Account 1830 (PP&E) and a corresponding amount being debited to O&M expenses for 2017 and retained earnings to account for prior years.
c. **Depreciation Errors.** In preparing its current year financial statement, ENWIN management discovered that componentization errors for the 2011-2017 period

that caused the wrong useful lives to be used to calculate depreciation expenses (for examples transformers were given a useful life of 45 years, rather than the 35-40 years consistent with the Kinetrics report), which resulted in an understatement in depreciation expense. In addition, a mathematical/clerical error was identified in the 2011-2017 period which resulted in the wrong remaining useful life being applied to a number of assets, which also resulted in an understatement of depreciation expenses. Finally, depreciation was also impacted by the burden rate adjustment noted above. The correction resulted in $2,872,258 being credited to Accumulated Depreciation and 2017 depreciation expense and retained earnings being debited by an equivalent amount.

d. **Tax Adjustments.** Finally, the above noted adjustments caused a reduction to tax expense and a reduction to deferred tax in the 2011-2017 period.

A copy of the details provided to the OEB associated with the above corrections is included in Attachment A with this letter.

On May 23, 2018, ENWIN staff met with OEB staff from licensing, reporting, audit and rates groups to discuss the above noted matters. The purposes of this letter is to provide a summary of the matters discussed during this meeting, and to provide ENWIN's follow-up to various items that were requested by OEB staff.

The focus of the meeting was on various matters associated with a recast of prior years' financial information in ENWIN's 2017 Audited Financial Statements, and its impact on RRR reporting for the year. In addition to appearing in ENWIN's 2017 Audited Financial Statements, the impact of these prior year corrections were booked through retained earnings in ENWIN's 2017 RRR reporting so that 2017 results would accurately reflect the results of operation for the year.

At the May 23rd meeting OEB representatives enquired regarding the current state of depreciation practices at ENWIN and asked if the new management team felt depreciation practices were now in line with the Accounting Procedures Handbook (APH) and the Kinetrics report. ENWIN indicated that they had not yet had the opportunity to completely review all PP&E items, but that they felt that practices where now materially compliant with the APH and Kinetrics report, and that it is currently planned that any future refinements would be treated prospectively.

Prior to the May 23rd meeting, ENWIN provided updated calculations for Regulated Return on Equity (RROE) it was noted that ENWIN's updated RROE was below the 300 bps "dead band" for each of 2014, 2015, 2016 and 2017. Details of the calculations are provided in Attachment B with this letter. ENWIN noted that while its current financial results were weaker than the threshold identified by the OEB as acceptable, it should not be a cause for immediate financial concern because the risk of weaker financial performance was currently mitigated by ENWIN's strong cash position, low levels of debt and operating facilities available in ENWIN's parent company. ENWIN representatives remain confident that the company can adequately fund its operating and capital needs together with its shareholder dividend expectations.

Risk associated with the weak financial performance will also be mitigated by ENWIN's planned future Cost of Service (COS) application. During the May 23rd meeting, OEB staff inquired about the timing of a COS application for ENWIN and advised that ENWIN should issue a nomination letter to get scheduled for a COS application since ENWIN is currently an annual IR filer. On June 27, 2018 ENWIN wrote to the Board to notify the OEB of ENWIN's plan to file a cost of service application for rates to be effective January 1, 2020. (Copy attached, Attachment C)

As Management prepares the necessary schedules for its upcoming COS application, prior year financial results impacted by the adjustments discussed in this letter will be incorporated, and the COS application will be reported on a restated basis. As this work completes later this year, management will contact OEB staff and make arrangements to update its previous year RRR reporting, including RROE and trial balance as deemed necessary at that time based on further review and consultation with OEB staff.

During the May 23rd meeting, the scope of ENWIN's annual external financial statement audit was discussed including the fact that ENWIN has not recognized regulatory assets and liabilities in its financial statements as a result of not being eligible to adopt IFRS 14 – Regulatory Deferral Accounts. IFRS 14 was not available to companies who were early adopters of IFRS such as ENWIN who converted in 2012. As a result of this, ENWIN's Group 1 and Group 2 accounts had not been subject to annual audit.

Accordingly ENWIN has retained KPMG's utility group to arrange for special audit work to be performed on these balances as recommended by ENWIN's Board of Directors. During the meeting, OEB staff indicated that the OEB would require an independent audit on Group 1 accounts before ENWIN's next IRM, and an audit of both Group 1 and Group 2 accounts before ENWIN's COS application if these accounts were to be cleared in those applications. It was agreed the procedures recommended by KPMG would be shared with the OEB's audit group prior to the work commencing to optimize the work. A summary of Specified Audit Procedures proposed by KPMG was provided to the OEB staff on July 4th. OEB staff provided feedback concerning these procedures which included several recommendations and the requirement that an audit under CAS 800 rather than a report on specified procedures would be required. ENWIN will work with KPMG to fulfil this requirement and inform the OEB's Audit and Investigations group of progress and procedures to be performed as part of the audit.

I would like to again thank you for meeting with us in May. We look forward to working with all necessary departments of the OEB to resolve these matters to your satisfaction.

If you have any questions regarding the content of this letter please do not hesitate to contact me at the number below.

Yours very truly,

ENWIN Utilities Ltd.

Byron Thompson
VP Finance and CFO
519-255-2869
bthompson@enwin.com

cc:

Paul Gleason, Director of Regulatory, ENWIN Utilities Ltd.

Matt Carlini, Director of Finance, ENWIN Utilities Ltd.

Helga Reidel, President & CEO, ENWN Utilities Ltd.

Ben Bosch, Senior Advisor, OEB

Tony Stanco, Manager, Audit and Investigation, OEB

Attachments:

Attachment A: Changes to Account Balances 2018 04 19

Attachment B: Regulated ROE recalculation 2012 - 2016

Attachment C: Enwin 2020 nomination letter (copy – original previously sent)

**ENWIN Utilities Ltd**
**Summary of Restated Property, Plant and Equipment & Regulatory liabilities**
**as at December 31, 2017**

**Issue 1: 1575 Catch up**

Upon inspection of the regulatory liability accounts it was noted that annual adjustments to the 1575 account were not made since the initial entry in 2012. Taking into account the adjustments noted below related to depreciation and burden, the balance that should have been recorded in account 1575 and what was previously report are sumaried below:

| account: 1575 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| as reported: | (10,530,352) | (10,530,352) | (10,530,352) | (10,530,352) | (10,567,390) | (10,567,390) |
| revised: | (7,771,542) | (10,369,050) | (12,634,876) | (14,569,146) | (16,940,510) | (19,220,838) |
| Difference - reported vs revised | 2,758,810 | 161,302 | (2,104,524) | (4,038,794) | (6,373,120) | (8,653,448) |
| Annual P&L impact | | (2,597,508) | (2,265,826) | (1,934,270) | (2,371,364) | (2,280,328) |

For purposes of reporting this year, the entry below was booked record the entry.

| | | | | | |
|---|---|---|---|---|---|
| Journal entry: | Dr | 4310 | Regulatory Credits | 2,280,328 | |
| | Dr | 3045 | Retained earnings | 6,373,120 | |
| | Cr | 1575 | IFRS CGAAP Transitional Account | | 8,653,448 |

**Issue 2: Financial Statement Restatement with impacts to 2.1.7**

**In preparation of the current year financial statements Enwin management discovered errors dating back to the 2012 conversion to IFRS. In Enwin's 2017 audited financial statements, a recast (restatement) of prior year numbers was done to correct these errors.**

There were generally two types of errors identified and restated. A description of the error and $ amount of adjustment made on account of each year are provided below:

***a) Burden rates were incorrect***

*ENWIN*s burden rates were overstated as a result of errors. Specifically, non direct management was included in the calculation and mathematical errors were also embedded in the calculation of the burden rate that was applied to capital labour. These results of these errors was an understatement of O&M expenses and overstatement of PP&E.

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| Over capitalization | (780,721) | (639,896) | (826,821) | (1,019,465) | (762,269) | (745,711) | (825,488) |
| Cumulative impact | | | | | | (4,774,883) | |

Similair to how the entry was proposed above for account 1575, the entry below was booked in 2017 to correct this error.

| | | | | | |
|---|---|---|---|---|---|
| Journal entry | Dr | 5005-5175 | O&M expense | 825,488 | |
| | Dr | 3045 | Retained earnings | 4,774,883 | |
| | Cr | 1830 | Property, Plant and Equipment | | 5,600,371 |

***b) Componentization and Mathematical Errors calculating Depreciation***

Componentization errors caused the wrong useful lives to be used to calculate depreciation expenses. Specifically, transformer useful lives should have been 35 or 40 years consistent with the Kinetrics report but instead the power transformer category was selected with a useful life of 45 years. Enwin had failed to componetize its transformers and included all submerible, pad mounted and pole mounted transformers in one category, utilizing the power transformer useful life. That resulted in an understatement of depreciation expenses.
Additionally Some mathematical / clerical errors were also identified during the review of our subledger which resulted in the wrong remaining useful life being applied to a number of assets. That also resulted in depreciation expense being understated.
- Depreciation was also impacted by the burden rate adjustements noted above.

The chart below summarizes the understatement of depreciation that occurred in each year (or the increase that was booked to correct it) The amounts below are net of the offsetting impact of utilization of lower burden rates as described in (a) above.

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| Understated Depreciation | (469,358) | (452,845) | (427,828) | (412,060) | (394,896) | (370,520) | (344,751) |

| | | | | | |
|---|---|---|---|---|---|
| Journal entry | Dr | 5,705 | Depreciation expense | 344,751 | |
| | Dr | 3,045 | Retained earnings | 2,527,507 | |
| | Cr | 2,105 | Accumulated Depreciation | | 2,872,258 |

***c) Tax adjustments as a result of the adjustments above.***

| | 2,011 | 2,012 | 2,013 | 2,014 | 2,015 | 2,016 | 2,017 |
|---|---|---|---|---|---|---|---|
| Reduction to tax expense | | | | 270,158 | 202,001 | 197,613 | 218,754 |

| | 2,011 | 2,012 | 2,013 | 2,014 | 2,015 | 2,016 | 2,017 |
|---|---|---|---|---|---|---|---|
| Reduction to deferred tax | 124,380 | 120,004 | 113,375 | 109,196 | 104,648 | 98,188 | 91,359 |

**ENWIN Utilities Ltd**
**Summary of Restated Property, Plant and Equipment & Regulatory liabilities**
**as at December 31, 2017**

| | | | | | |
|---|---|---|---|---|---|
| Journal entry: | Dr | 1,110 | PILs receivable | 888,527 | |
| | Cr | 3,045 | Retained earnings | | 669,773 |
| | Cr | 6,110 | Income tax expense | | 218,754 |
| | Dr | 1,495 | Future PILs receivable | 761,148 | |
| | Cr | 3,045 | Retained eamings | | 669,789 |
| | Cr | 2,320 | Future PILs liability | | 91,359 |

**Total**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Change to regulatory Net Income (reduction) | 1,666,069 | (3,852,158) | (3,427,193) | (2,889,434) | (3,289,981) | (3,231,813) |

( Includes 1575 but
excludes deferred tax )

**Impacts on RRR :**

2.1.5 Capital - A) Gross Capital additions

| | MIFRS 2012 | MIFRS 2013 | MIFRS 2014 | MIFRS 2015 | MIFRS 2016 | MIFRS 2017 |
|---|---|---|---|---|---|---|
| as filed: | 17,468,716 | 20,091,775 | 19,920,856 | 22,631,448 | 18,697,650 | |
| revised: | 16,828,820 | 19,264,954 | 18,901,391 | 21,869,179 | 17,951,939 | 15,854,524 |

2.1.5 Capital - B) Capitalized overhead

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| as filed: | 1,803,642 | 2,246,126 | 2,497,727 | 2,280,423 | 2,184,126 | |
| revised: | 1,163,746 | 1,419,304 | 1,478,263 | 1,518,154 | 1,438,415 | 1,303,826 |

2.1.5.6 Regulated ROE

A full review of the restated regulated ROE has not been completed due to the time constraints.
Regulatory net income would be reduced by "Change to regulatory Net Income" as noted above.
The result in 2017 is that the Regulated ROE is below the 300 basis point dead band.

Attachment B

**Enwin Utilities Ltd**
**Adjustments to Regulated Return on Equity**
**Based 2017 Year End Adjustments for Burden, Depreciation and Account 1575**

| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| **Regulated Net Income - as reported** | a | | 6,601,023 | 15,808,168 | 14,037,539 | 12,807,585 | 12,398,320 | 7,239,720 |
| **Adjustments** | | | | | | | | |
| Rerverse 1575 / 4310 | | | 6,043,626 | | | | | |
| Corrected 1575 / 4305 /4310 | | | (4,389,506) | (2,597,508) | (2,265,827) | (1,934,269) | (2,371,364) | (2,280,328) |
| Adjustment for Burdens | | (780,721) | (639,896) | (826,821) | (1,019,465) | (762,269) | (745,711) | (825,488) |
| Tax impact of Burden adjustment | | | 0 | 0 | 270,158 | 202,001 | 197,613 | 218,754 |
| Adjustment for Depreciation | | (469,358) | (452,845) | (427,828) | (412,060) | (394,896) | (370,520) | (344,751) |
| Total Adjustments | b | | 561,378 | (3,852,157) | (3,427,193) | (2,889,433) | (3,289,981) | (3,231,813) |
| **Regulated Net Income - as corrected** | c = a+b | | 7,162,402 | 11,956,011 | 10,610,345 | 9,918,151 | 9,108,338 | 4,007,907 |
| **Adjustments for Regulated Return Calculations , not included in earlier ROE Schedules** | | | | | | | | |
| Remove non utility accounts 4375/4380 | d | | (2,217,711) | (1,145,597) | (1,383,098) | (1,727,076) | (1,114,832) | (1,027,413) |
| Total Adjustments for Regulated ROI recalculations | b +d | | (1,656,333) | (4,997,754) | (4,810,291) | (4,616,510) | (4,404,813) | (4,259,225) |
| Regulated Net Income for RROE , excluding non reg | | | 4,944,691 | 10,810,414 | 9,227,247 | 8,191,075 | 7,993,507 | 2,980,494 |
| Regulatory Return on Equity - Reported | | | 3.48% | 13.04% | 9.62% | 6.88% | 5.92% | 2.50% |
| Regulatory Return on Equity - Recalculated | | | 1.81% | 8.24% | 5.37% | 4.03% | 3.64% | 2.50% |

Attachment C
(Copy)

June 27, 2018

**COURIER & EMAIL**

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

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

**Re: ENWIN Utilities Ltd. - Plans for Filing Cost of Service Application**

ENWIN Utilities Ltd. ("ENWIN") filed an Annual IR Index application for 2018 rates on November 6, 2017 (EB-2017-0037) and, for 2019 rates, ENWIN again plans to file using the Annual IR Index methodology.

ENWIN is writing to advise the Board that ENWIN anticipates filing a cost of service application for rates to be effective January 1, 2020 including a consolidated distribution system plan.

Yours truly,

**ENWIN Utilities Ltd.**

Helga Reidel
President & CEO

cc: Director of Regulatory Affairs, ENWIN Utilities Ltd.
Vice President Finance & CFO, ENWIN Utilities Ltd.

# Correspondence

# Dated

# March 15, 2019 – May 16, 2019

RE: [External] RE: ENWIN Utilities Ltd RRR filing
Stephanie Chan
to:
'Paul Gleason'
2019-05-16 12:27 PM
Cc:
"Ben Bosch", "Matt Carlini", "Shahdil Alibhai"
Hide Details
From: "Stephanie Chan" <Stephanie.Chan@oeb.ca>
To: "'Paul Gleason'" <pgleason@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>, "Matt Carlini" <mcarlini@enwin.com>, "Shahdil Alibhai" <Shahdil.Alibhai@oeb.ca>

Hi Paul,

May 23 at 10am works for us. Please provide us a number to call you.

Thanks,
Stephanie

**From:** Paul Gleason <pgleason@enwin.com>
**Sent:** Thursday, May 16, 2019 11:17 AM
**To:** Stephanie Chan <Stephanie.Chan@oeb.ca>
**Cc:** Ben Bosch <Ben.Bosch@oeb.ca>; Matt Carlini <mcarlini@enwin.com>; Shahdil Alibhai <Shahdil.Alibhai@oeb.ca>
**Subject:** RE: [External] RE: ENWIN Utilities Ltd RRR filing

Stephanie,

How is Thursday, May 23rd at 10am?

Paul

**Paul Gleason**
Director Regulatory Affairs & Corporate Secretary
ENWIN Utilities Ltd.

pgleason@enwin.com
P. (519) 251-7325
C. (226) 346-0106

787 Ouellette Ave. | P.O. Box 1625 Station A | Windsor, Ontario | N9A 5T7

www.enwin.com @ENWINUtilities youtube.com/ENWINUtilitiesLtd

**Our Vision: To be a trusted leader in providing exceptional value and services to our customers and stakeholders.**



From: "Stephanie Chan" <Stephanie.Chan@oeb.ca>
To: "'Paul Gleason'" <pgleason@enwin.com>
Cc: "Matt Carlini" <mcarlini@enwin.com>, "Ben Bosch" <Ben.Bosch@oeb.ca>, "Shahdil Alibhai" <Shahdil.Alibhai@oeb.ca>
Date: 05/16/2019 10:58 AM
Subject: RE: [External] RE: ENWIN Utilities Ltd RRR filing

---

Hi Paul,

Are you available next Thursday May 23 or Friday May 24 instead?

Thanks,
Stephanie

**From:** Paul Gleason <pgleason@enwin.com>
**Sent:** Thursday, May 16, 2019 9:52 AM
**To:** Stephanie Chan <Stephanie.Chan@oeb.ca>
**Cc:** Matt Carlini <mcarlini@enwin.com>
**Subject:** RE: [External] RE: ENWIN Utilities Ltd RRR filing

Stephanie,

We have received your message. Matt and I would like to schedule a call with you to discuss this matter.

Are you available on Wednesday, May 22nd at 1:00pm? Let me know and I will schedule the call.

Thank you.
Paul

**Paul Gleason**
Director Regulatory Affairs & Corporate Secretary
ENWIN Utilities Ltd.

pgleason@enwin.com
P. (519) 251-7325
C. (226) 346-0106

787 Ouellette Ave. | P.O. Box 1625 Station A | Windsor, Ontario | N9A 5T7

www.enwin.com @ENWINUtilities youtube.com/ENWINUtilitiesLtd

**Our Vision: To be a trusted leader in providing exceptional value and services to our customers and stakeholders.**



From: "Stephanie Chan" <Stephanie.Chan@oeb.ca>
To: "'Matt Carlini'" <mcarlini@enwin.com>
Cc: "Ben Bosch" <Ben.Bosch@oeb.ca>, "Sagar Kancharla" <Sagar.Kancharla@oeb.ca>, "Byron Thompson" <bthompson@enwin.com>, "Paul Gleason" <pgleason@enwin.com>, "Shahdil Alibhai" <Shahdil.Alibhai@oeb.ca>
Date: 05/10/2019 03:51 PM
Subject: RE: [External] RE: ENWIN Utilities Ltd RRR filing

---

Hi Matt,

Thank you for your email and apologize for the delay in a response.

Ben Bosch and I have reviewed your email and the information provided in the Excel file. First, we would like to correct a misunderstanding regarding revisions to the reporting and the process under the RRRs. We did confirm with EnWin that regulatory reporting changes arising for EnWin multi-year accounting and reporting errors would not impact previously published material such as yearbooks, scorecards and benchmarking reports. However, we indicated that revisions to the RRRs would be pending subject to a review of more detailed information (e.g., details on the PP&E and other account changes) to be submitted to OEB staff.

As such, having received and reviewed the requested details in support of EnWin's proposed changes in the Excel file, we request that EnWin undertake to amend its reporting in RRR sections 2.1.7 (trial balance for all applicable accounts), 2.1.5.2 (capital) and 2.1.5.6 (ROE) for all applicable years. This supports the quality, completeness, accuracy and reliability of the reported data in compliance with the OEB's policies and requirements under the RRRs.

However, before EnWin can proceed with amending its reporting, we have the following requests.
1. The "(Profit)/Loss" figures in the Excel document does not match the "Regulatory Net Income – as corrected" figures provided in EnWin's letter to the OEB (dated July 26, 2018 – Attachment B) covering the reporting periods from 2017 to 2013. Summarized comparisons reflect the differences in the regulatory net incomes in these two documents in the table below. Please provide a reconciliation for each year and explanations to support the changes shown in the Excel document as compared to that of the July 2018 letter.

**EnWin's Proposed Regulatory Accounting Changes**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Regulated Net Income (Letter 20190726) | 7,162,402 | 11,956,011 | 10,610,345 | 9,918,151 | 9,108,338 | 4,007,907 |
| Summary Changes (Excel file) | 7,162,402 | 11,395,868 | 9,088,748 | 9,222,678 | 8,907,351 | 7,239,720 |
| Difference | - | 560,143 | 1,521,597 | 695,473 | 200,987 | - 3,231,813 |

Note: Excel file "(Profit)" figures restated as positive figures for comparison to regulatory net income per letter.

2. The reporting changes to the trial balances (RRR 2.1.7) for the 2017 to 2012 reporting periods have implications on other reporting sections of the RRRs. In order to ensure that reporting in the affected sections are appropriately updated, please provide high-level summary changes to facilitate revisions to the following sections for the 2016 to 2012 reporting periods:
a. RRR 2.1.5.6 ROE (recalculated in accordance with restated regulatory account figures)
b. RRR 2.1.5.2 capital (restated in accordance with revised PP&E account figures)

We would appreciate receiving this information within the next two weeks, and once these items are reviewed, we will discuss with you the next steps and the timing for the amendments to the reporting in the e-Filing System.

Thanks,
Stephanie

**From:** Matt Carlini <mcarlini@enwin.com>
**Sent:** Friday, March 15, 2019 1:36 PM
**To:** Stephanie Chan <Stephanie.Chan@oeb.ca>
**Cc:** Ben Bosch <Ben.Bosch@oeb.ca>; Sagar Kancharla <Sagar.Kancharla@oeb.ca>; Byron Thompson <bthompson@enwin.com>; Paul Gleason <pgleason@enwin.com>
**Subject:** Re: [External] RE: ENWIN Utilities Ltd RRR filing

A virus (GenericMac) was detected in the file (2.1.7 ENWIN Summary Changes filing-OEB submission 2019-03-13.xlsm/xl/vbaProject.bin). Action attachment.

Good afternoon Stephanie,

In 2018, ENWIN Utilities Ltd. met with OEB staff to discuss a correction ENWIN was making to the burden and capitalization rates used when ENWIN converted from Canadian GAAP to IFRS. The discussion also addressed the 2017 audited financial statement restatement, impacts on the 1575 calculation and other RRR filing topics. During that meeting, OEB staff requested that ENWIN submit a summary of the changes discussed but confirmed that the RRR filings, yearbook and other publications would not be modified. ENWIN mentioned that a cost of service was being prepared and requested time to ensure that the amounts presented to the OEB would agree with the upcoming cost of service filing.

ENWIN is now in a position where the cost of service values are drafted and ENWIN is able to release the summary information to the OEB for information purposes.

The main highlights contained within the summary are as follows:
1. Changes in burden and capitalization rates caused changes in the General Administrative Salaries Exp (USoA 5615); Amortization expense (USoA 5705) and corresponding capital asset and accumulated amortization accounts.
2. Those adjustments changed the carrying balance of the 1575 balance and a result, the IFRS-CGAAP transitional account (USoA 1575) and Regulatory Credit (USoA 4310) account have been updated accordingly.
3. Some of those changes also impacted income and deferred taxes and as a result, those balances have been amended.
4. Other Comprehensive Income (OCI) balances were not recorded correctly in all years and as a result those balances have also been amended. The accounts impacted were USoA 3090, 7010 and 7025
5. The 2015 year has entirely been restated. The OEB directed ENWIN to report under CGAAP for the 2015 year but in 2014 and 2016 requested MIFRS. The 2015 MIFRS balances have been provided and as a result several accounts are different.
6. In an effort to improve reporting subtle improvements are being submitted. The largest adjustment is reallocating costs between USoA 5005 into 5014 and 5015. This is being done in response to OEB staff questions during last year's RRR review.

ENWIN does have the unique situation where the audited financial statements are reported under IFRS and our regulatory reporting is under MIFRS. Our auditors are now providing assurance on our Group 1 and 2 accounts and will be fully audited for the upcoming Cost of Service application.

If you have any questions or need additional information, please do not hesitate to contact me.

Best Regards,

**Matt Carlini**, CPA, CA
Director Finance
ENWIN Utilities Ltd.

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**Our Vision: To be a trusted leader in providing exceptional value and services to our customers and stakeholders.**



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## 1 - OEB Staff - 7

Reference:

EnWin Utilities' Response to the Incomplete Letter dated May 17, 2019

Preamble:

EnWin Utilities filed the 2018 AFSs as part of the updated evidence to respond to the incompleteness letter dated May 17, 2019. EnWin Utilities also states that it will file the 2018 annual report as required during the interrogatory process.

Question:

a) Please provide the 2018 annual report.

b) Given the 2018 audited actual numbers are available, please update the schedules and evidence using the actual numbers in the 2018 AFSs.

---

Response:

a) Please see OEB Staff 7 - Attachment 1 for the 2018 Annual Report for Windsor Canada Utilities Ltd.

b) ENWIN has updated the Chapter 2 appendices using the actual numbers in the 2018 AFSs. The updated appendices are filed with the response to AMPCO – 3.

Attachment 1: 2018 Annual Report of Windsor Canada Utilities Ltd.

# 2018 Annual Report

Windsor Canada Utilities Ltd.

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## Cover Photo

ENWIN Powerline Maintainers Mark Wigfield, Andrew Norman and Chad Hedrick.

## Back Cover Photo

The ENWIN Kinetic Geode at the Rotary Club of Windsor (1918) Centennial Plaza on Windsor's riverfront.

# Message from Windsor Canada Utilities Ltd.

Mayor Drew Dilkens
Board Chair
LL.B, MBA, DBA, CHRL

## Powering Diversification

2018 brought into focus Windsor's achievements, its goals and its direction as a city. We confirmed our municipal government for the next four years – and with that confirmation, we committed ourselves to working diligently to keep moving our city in the right direction.

As Mayor of Windsor, I am inspired by that direction.

As Chair of the Board of Directors of Windsor Canada Utilities Ltd., I am proud of ENWIN's role in supporting our city, through its excellence in delivering the electricity and water our businesses and residents need. I also support and appreciate ENWIN's dedication to building the partnerships that will sustain us in the future and help us to thrive.

Like many cities across North America, Windsor has weathered some severe economic challenges. We are pleased to see progress in our business community, and we welcome a recent rebound in manufacturing, along with an influx of investment from abroad.

These developments have helped set Windsor on a path to success in some of our key areas. ENWIN has played an important role in that turn-around.

ENWIN's disciplined, strategic, focused approach to business and its expertise in innovation and technology have helped build the bridges we need – between people, businesses and nations – to maintain our new direction.

We realize there is a lot more to do. With this realization comes a sense of urgency.

Windsor must continue to be proactive in seeking ways to diversify our economy, and it is reassuring to know that, as opportunities emerge, ENWIN will be there to support that work. We will need ENWIN's knowledge and expertise as we fast-track changes to our local economy.

Our strategic focus on people is the same – whether we describe them as electricity and water customers, business owners, residents or citizens of Windsor. Through that focus, we are committed to harnessing all our energy, talent and commitment, to ensure a secure future for the City of Windsor. We know that we are strongest when we work together.

Sincerely,

Mayor Drew Dilkens
Board Chair - Windsor Canada Utilities Ltd.

# Message from Windsor Canada Utilities Ltd.

Helga Reidel
President and CEO
CPA, CA, ICD.D

## Aligning with Customer Needs

2018 was a year of preparation, change and innovation for the ENWIN Group of Companies.

We launched our new website, updated our Conditions of Service for our customers and joined the GridSmartCity® consortium of electricity distributors to focus, with our LDC colleagues, on achieving cost efficiencies. We also launched a new company – ONtech Rapid Coatings Inc. – under our unregulated ENWIN Energy division.

We created a new forum called ENnovation, through which our frontline employees can develop and share their innovative ideas. This helped us to improve the workflow within our companies, bring new ideas and new lines of business to the forefront for ENWIN to explore.

Throughout 2018, employees across numerous departments and divisions engaged in research, reporting, forecasting and customer outreach to prepare for ENWIN Utilities Ltd.'s 2020 Cost of Service application and its submission to the Ontario Energy Board (OEB), as is required from time to time.

Given that it has been more than 10 years since ENWIN has filed such an application, this was an intricate process. It required a thorough review of our accounts and activities, leading to the development of a new rate structure which we anticipate will become effective in 2020.

The impetus for all these activities was established during our 2016 Board of Directors' Strategic Planning sessions. Through this planning process, Windsor Canada Utilities Ltd. reinforced our corporate values and established our strategic focus, placing the customer at the top of our priorities.

In response to this strategic direction, our management team reached out to multiple customers groups, and prepared a Business Plan, a Distribution System Plan and an Asset Management Plan, which support our rate application to the OEB.

While we continued to plan for future years in 2018, we also undertook investment in our current regulated assets, to sustain our system reliability. Along with this, we continued our focus on the growth of our unregulated businesses.

As we reached out to customers, we confirmed that cost remains a top priority. We are proud of our history of keeping rate increases below the cost of inflation over the past decade, and this will remain part of our plan.

We look forward to continuing to offer excellent, cost effective service to our customers.

Sincerely,

Helga Reidel
President & CEO - Windsor Canada Utilities Ltd.

# Company Profile

**Windsor Canada Utilities Ltd. (WCU, the Company or the Corporation),** is 100 percent owned by The Corporation of the City of Windsor. It is a private company, registered under the Ontario Business Corporations Act, and overseen by a Board of Directors consisting of six members appointed by City Council. The core businesses of the Corporation, through its regulated and unregulated affiliates, are electricity distribution and energy and utility services. The Company owns and operates two subsidiary companies.

**ENWIN Utilities Ltd. (EWU, or ENWIN)**, the first of these two subsidiaries, is a regulated electricity Local Distribution Company (LDC) operating in the City of Windsor. ENWIN maintains an electricity distribution system, serving approximately 89,000 residential and commercial customers. As a condition of its distribution licence, ENWIN was required in 2018 to meet Conservation and Demand Management (CDM) targets established by the Ontario Energy Board (OEB). ENWIN also maintains a contract of service with the **Windsor Utilities Commission (WUC)** to manage WUC's administrative and operational functions, and to supply water to the residents of Windsor and two neighbouring towns.

**ENWIN Energy Ltd. (EWE)**, the second of these subsidiaries, provides streetlight and sentinel light maintenance services to the City of Windsor and residents, as well as engaging in partnerships to offer energy related services.

**Windsor Utilities Commission (WUC)**, owns the water treatment and distribution system in the City of Windsor, and is responsible for setting water rates for customers in Windsor. WUC has contracted with EWU to manage the treatment of potable water and distribution to residents and businesses in Windsor, as well as wholesale water transmission to the neighbouring towns of Tecumseh and LaSalle.


**ENWIN Hydro crews install new distribution infrastructure on Tecumseh Road.**

# Corporate Governance

WCU is committed to establishing and maintaining leading governance practices for a company of its size and mandate. Because governance standards and best practices are always evolving, the company seeks to continuously improve its practices.

WCU is a private, for-profit company, incorporated under the Business Corporations Act (Ontario).

At the same time, the Company is wholly owned by the City of Windsor and, through its wholly owned subsidiaries, fulfills a public mandate. It is, therefore, mindful of its responsibility to be accountable both to its shareholder and the public.

The Company's governance practices are determined, not simply by legal obligations, but by best business practices and standards established by independent agencies.

While WCU is not a reporting issuer under the Securities Act, and is therefore not subject to governance standards that apply to publicly-traded companies, the company is guided by these standards and strives to meet or exceed them.

## Governance Structure

Accountability for the effective oversight of WCU, and its wholly-owned subsidiaries EWU and EWE, rests with a six-member Board of Directors, which provides direction on behalf of the shareholder, the City of Windsor.

The Board provides leadership within a framework of effective controls that enables risks to be assessed and managed. The Board is responsible for supervising the management of the business affairs of WCU and its wholly-owned subsidiaries.

In carrying out its oversight function, the Board of Directors is guided by a Shareholder Declaration issued by Windsor City Council and revised from time to time. The Board adheres to the City's Code of Conduct for Members of Council and Local Boards.

A separate Board of Directors was established to oversee the operations of EWU, in accordance with the Affiliate Relationships Code for Electricity Distributors and Transmitters, issued by the Ontario Energy Board. The powers and functions of that Board are set out in a shareholder declaration issued by the WCU Board of Directors.

On a day-to-day basis, the Corporation is led by an executive management team, comprised of the President and Chief Executive Officer, the Chief Financial Officer and the senior executives of the critical functional areas.

This team oversees the alignment of business practices and strategies with the goals of the Company, and drives performance by managing risks and opportunities. The executive management team is accountable to the corporation's Boards of Directors through the President and Chief Executive Officer.

## Appointments to the Board of Directors

The governance structure for WCU and its wholly-owned subsidiaries includes three boards of directors – the Windsor Canada Utilities Ltd. Board, the ENWIN Utilities Ltd. Board and the ENWIN Energy Ltd. Board.

The City of Windsor appoints all Directors to the Windsor Canada Utilities Ltd. Board. In doing so, the City considers candidates that may be recommended by the WCU Board, but is not obliged to select these candidates.

As set out in the shareholder declaration, all candidates for appointment to the Board must meet certain requirements, including demonstrated integrity and high ethical standards, relevant career experience and expertise, and an understanding of the role of WCU and its subsidiaries, both as a service to local ratepayers and as an asset of taxpayers.

In addition, the selection process is designed to maintain a board that includes the following overarching competencies among one or more directors:

- A strong business background, including competitive business experience and strategic planning;
- A strong financial background, including financial accreditation and public or private market financing experience;
- Industry sector experience in the areas of business of the subsidiary companies; and
- Governance/Board experience.

All new Directors undergo an orientation and education program upon their appointment to the Board.

## Committees

The following Committees were created to help the Boards of Directors carry out their duties. The committees meet regularly and provide feedback on their discussions to their respective Boards.

**Audit and Finance Committee (Windsor Canada Utilities Ltd. and ENWIN Utilities Ltd.)**

The Audit & Finance Committees review financial statements, accounting practices and policies, auditing processes and the results of internal and external audits and related matters. These committees also oversee financial risk management and assess internal controls.

**Governance and Human Resources Committee (ENWIN Utilities Ltd.)**

The Governance and Human Resources Committee reviews the Corporation's governance structures and provides oversight to policies and practices impacting employees.

**Executive Committee (ENWIN Utilities Ltd.)**

The Executive Committee reviews and assesses the performance of the President and Chief Executive Officer, on behalf of the Board of Directors, and provides input, advice and guidance to the President & CEO regarding strategic direction of the companies.

# Executive Compensation

The ENWIN Group is committed to providing a competitive total compensation strategy that will allow the organization to attract and retain talented management and staff, who align with the corporate vision and values and contribute to the success of the Company, while being cognizant of the fiscal responsibility to rate payers.

The utility seeks competitiveness in the employment market through compensation and benefits practices that are equitable, consistent, practical and in accordance with the legal requirements of the Employment Standards Act, Pay Equity Act, Canada Revenue Agency (CRA) and other applicable legislation.

The ENWIN Group is also committed to developing and maintaining salary and benefit practices and procedures that provide an effective means of controlling expenditures, and are responsive to the changing conditions within the community. All compensation and benefits programs are influenced by the economic health of the company and our community.

The Governance and Human Resources Committee, comprised of members of the Board of EWU, is responsible in concert with the Executive Committee, for developing and recommending the approval of the compensation framework for management.

In developing the compensation framework, the committees are guided by the need to provide a total compensation package that will attract and retain qualified and experienced executives and by the best practice of linking compensation to performance.

Additionally, The ENWIN Group makes an effort to offer a total compensation package that is competitive with other organizations of similar size, scope and geographic and economic composition.

A market comparison, aided by an independent consultant, was performed in 2016, and comparators from both the public sector and private sector, as well as direct industry comparators, were sought. Findings were that compensation was comparable.

Executive compensation is ultimately approved by the Board of Directors. In making its recommendations to the Board, the committee examines the responsibilities and performance of individual executives, and considers the recommendations of the President and Chief Executive Officer.

Total cash compensation for Executives consists of two components: base salary and a variable performance incentive opportunity. Total cash compensation is benchmarked to companies of comparable size and scope in both the Ontario and national markets.

The variable performance incentive opportunity is paid on an annual basis and is expressed as a percentage of base salary. It is designed to ensure alignment with corporate objectives, retain and motivate executives, and to reward them for their performance during the preceding year.

Payments are based on the achievement of both corporate and individual “stretch” objectives, both financial and non-financial, which are established each year and approved by the Board of Directors.

Non-financial targets are designed to achieve continuous improvement in relation to a number of strategic themes including, but not limited to, customer service, safety, innovation and overall management excellence.

Management and executives participate in a benefits program, which includes extended health care, dental care, basic and optional life insurance, and short-term and long-term disability insurance.

All employees also participate in the OMERS pension plan. This plan is a multi-employer, contributory, defined benefit pension plan established by the Province for employees of municipalities, local boards and school boards in Ontario.

Pension benefits are determined by a formula based on the highest consecutive five-year average of contributory earnings and years of service. Pension benefits are indexed to increases in the Consumer Price Index, subject to an annual maximum of six percent.

Both participating employers and participating employees are required to make equal contributions to the plan, based on the participating employees’ contributory earnings. Earnings for pension purposes are capped based on recent plan changes.

Although not a requirement for companies like WCU and its subsidiaries incorporated under Ontario’s Business Corporations Act, WCU’s wholly owned subsidiary, EWU, discloses the annual compensation of those serving in senior executive and board positions. It does so in keeping with the disclosure rules for corporations listed on the stock exchanges, and for companies that obtain funds through certain debt markets.

The ENWIN Group is also guided by the scope of disclosure demonstrated by certain companies in the energy sector, which, like ENWIN, are licensed and regulated by the OEB.

Directors receive an annual stipend and meeting fees for service. In the interest of transparency, the EWU Board members and senior executives have voluntarily consented to the disclosure of their remuneration in a public manner. This takes place in the spring of each year for the preceding year.

# Senior Management Team

**Helga Reidel**, CPA, CA, ICD.D
President & CEO

Helga Reidel has served as President and CEO of ENWIN since 2016, following more than 34 years of progressive experience, including Chief Administrative Officer with the City of Windsor, VP of the Windsor Detroit Tunnel Corporation and VP of Finance for Windsor Family Credit Union. She serves on several boards of directors and is a founding member of the Detroit/Windsor/Toledo Branch of the Private Directors' Association. Ms. Reidel graduated from the University of Windsor and the University of Toronto Rotman School of Business Institute of Corporate Directors. Her designations include B.Comm, B.Ed, CPA, CA, OCT, and ICD.D.

**John R. Wladarski**, C.E.T.
Vice President Shared Services & COO

Mr. Wladarski assumed the position of Vice President, Shared Services and COO in 2017, subsequent to 30 years in executive management positions in public works and the electrical and water distribution sectors in Ontario, including previous executive management positions in the hydro and water divisions at ENWIN. He is a graduate of Civil Engineering Technology at St. Clair College of Applied Arts and Technology, Leadership and Operations Management at the Ivey Business School at Western University, and the EDA Executive Development Program. He received the St. Clair Alumni of Distinction Award in 2012.

**Byron Thompson**, BA, B.Comm, CPA, CA
Vice President Finance & CFO

Byron Thompson joined ENWIN as Vice President Finance and CFO in January of 2017, after gaining extensive regulated sector experience as CFO for the Peterborough Utilities Group, along with nine years in regulated transportation businesses as Corporate Controller for the Manitoulin Transport Group and VP Finance for Coach Canada. Mr. Thompson studied at the University of Windsor and the University of Western Ontario. His degrees and designations include B. Comm, BA, CPA, CA and CPA (Illinois).

**Jim Brown**, P.Eng.
Vice President Hydro Operations

Mr. Brown joined ENWIN in 1999, following more than 20 years of experience in the natural gas distribution business. He has held progressively more responsible positions in engineering, operations and management, assuming the role of VP Hydro Operations in 2017. He holds an Engineering degree from the University of Western Ontario and a Business degree from the University of Windsor and is a registered Professional Engineer in the Province of Ontario.

## Garry Rossi, P.Eng.

Vice President Water Operations

Mr. Rossi has held progressive management positions with the ENWIN Group of Companies. As Vice President Water Operations, he leads the senior management team that develops the framework for a safe, reliable and efficient drinking water system. Prior to his work with ENWIN, Mr. Rossi held management, process and engineering positions within the automotive, wastewater and waste management sectors. Mr. Rossi holds an Honours Degree in Environmental Engineering from the University of Windsor and is a licensed Professional Engineer.

## Paul Gleason, LL.M.

Corporate Secretary & Director Regulatory Affairs

Mr. Gleason has held positions of increasing responsibility within the ENWIN Group of Companies for ten years, assuming the role of Corporate Secretary & Director Regulatory Affairs in 2016. His previous experience includes more than 12 years in progressive management roles in the automotive industry.  Mr. Gleason holds a Master of Laws (LL.M.) degree in Energy and Infrastructure Law, CSCMP from the Supply Chain Management Association and an Honours Bachelor of Economics degree from Laurentian University.

**The Senior Management team: (from left) Paul Gleason, Garry Rossi, Helga Reidel, Jim Brown, Byron Thompson, John Wladarski**

# Members of the Board of Directors (2014-2018)

## Windsor Canada Utilities Ltd.

**Drew Dilkens (Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Marty Komsa (Vice Chair)**
B.Comm
Executive Advisor, Strategic Planning, WFCU Credit Union

**John Elliott**
Councillor, City of Windsor, Ward 2

**Garnet Fenn**, MBA, DBA (Candidate), CPA,– CA, CMA, CGA (Ontario), CPA, CGMA, PFP (Michigan), CIM, FCIS, ICD.D, P.Adm., Acc.Dir.
Accountant and Financial Consultant

**Fred Francis**, BA, MA, B.Ed
Councillor, City of Windsor, Ward 1

**Jo-Anne Gignac**
Councillor, City of Windsor, Ward 6

## ENWIN Utilities Ltd.

**Vic Neufeld (Chair)**
MBA, CPA, CA, B.Sc.
CEO, Aphria Inc.

**Drew Dilkens (Vice Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Garnet Fenn**, MBA, DBA (Candidate), CPA, CA, CMA, CGA (Ontario), CPA, CGMA, PFP (Michigan), CIM, FCIS, ICD.D, P.Adm., Acc.Dir.
Accountant and Financial Consultant

**Jo-Anne Gignac**
Councillor, City of Windsor, Ward 6

**Marty Komsa**, B.Comm
Executive Advisor, Strategic Planning, WFCU Credit Union

**Abe Taqtaq**, BA
President, CD Ventures & Consulting Inc.

## ENWIN Energy Ltd.

**Drew Dilkens (Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Eddie Francis (Vice Chair)**
JD, HBSc
President and CEO, WFCU Credit Union

**Keith Andrews**, MPA, BA
Senior Vice-President & Managing Director, Gateway Casinos & Entertainment, Ontario

**Nancy Creighton**, B.Comm
Senior Business Advisor, Government of Ontario

**Peter Frise**, Ph.D., M.Sc.
Professor of Mechanical & Automotive Engineering, University of Windsor

**Jo-Anne Gignac**
Councillor, City of Windsor, Ward 6

**Kulveer Virk**, M.Eng, PMP
IT Program Manager

# Members of the Board of Directors (2019-2022)

## Windsor Canada Utilities Ltd.

**Drew Dilkens (Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Jo-Anne Gignac (Vice Chair)**
Councillor, City of Windsor
Ward 6

**Fred Francis**, BA, MA, B.Ed
Councillor, City of Windsor,
Ward 1

**Kevin Laforet**, B.Comm, CPA, CA
Regional President (Canada),
Caesars Entertainment

**Jim Morrison**, PFP
Councillor, City of Windsor,
Ward 10

**Jerry Udell**, BA, LL.B, C.S.
Senior Counsel, Miller
Canfield

## ENWIN Utilities Ltd.

**Drew Dilkens (Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Abe Taqtaq (Vice Chair)**, BA
President, CD Ventures &
Consulting Inc.

**Garnet Fenn**, MBA, DBA
(Candidate), CPA, CA, CMA,
CGA (Ontario), CPA, CGMA, PFP
(Michigan), CIM, FCIS, ICD.D, P.Adm.,
Acc.Dir.
Accountant and Financial
Consultant

**Jo-Anne Gignac**
Councillor, City of Windsor,
Ward 6

**Leo Muzzatti**, LL.B, B.Ed
Director of Human Resources
and Strategy Management,
Assisted Living Southwestern
Ontario (Windsor)

**Andrea Orr**
LL.M, CGA, CPA, CIRP, LIT
Licensed Insolvency Trustee

**George Wilkki**, P.Eng., LL.B
Retired City Solicitor,
City of Windsor

## ENWIN Energy Ltd.

**Eddie Francis (Chair)**
JD, HBSc
President and CEO,
WFCU Credit Union

**Drew Dilkens (Vice-Chair)**
LL.B, MBA, DBA, CHRL
Mayor, City of Windsor

**Rhea de Verteuil**, BSc
Director of People &
Processes, Sandalwood
Engineering & Ergonomics

**Gregory Ioanidis**, BMath, MBA
Former Vice President,
ITC Holdings Corp.

**Kieran McKenzie**, BA
Councillor, City of Windsor,
Ward 9


Public safety messages are displayed during every Windsor Spitfires ENWIN Safety Powerplay.

# Strategic Overview

WCU's 2018 Annual Report is the company's second to report against its 2017-2022 Strategic Direction, which outlines our business strategy.

In conjunction with its 2018 budget process, the company updated its financial projections for the next five years.

We will continue to update our targets and projections with each annual budget and five-year forecast, in response to continually evolving customer, industry, regulatory and political environment mandates. These updates will reflect important changes to the company itself, such as recognition of employee demographics, entry into new lines of unregulated business and regulatory requirements.

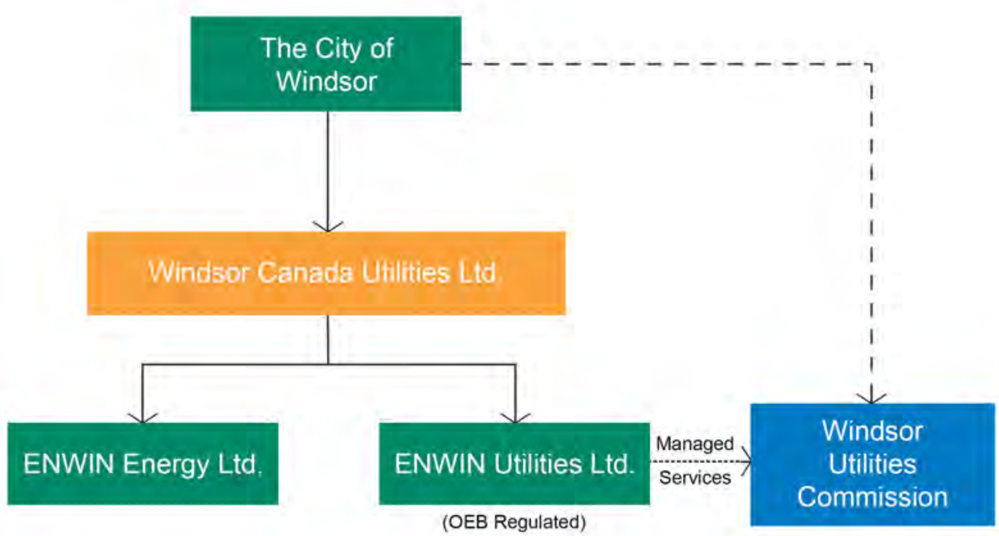
Throughout these changing dynamics — as reinforced in the Boards of Directors' Fall 2016 strategic session — WCU's vision remains: To be a trusted leader in providing exceptional value and services to our customers and stakeholders.

As demonstrated by our Strategic Compass (see page 21) — which is posted liberally throughout our workplaces — our strategic focus places the customer at the top of everything we do.

WCU believes that sharp focus on the value its subsidiaries provides to customers will generate positive results in all areas of performance — including financial strength and business growth, operational efficiency and effectiveness, and contributions to the community.

WCU's focus is people, both externally — our customers, our community and our stakeholders — and internally — our employees.

## The ENWIN Group



# Mission, Vision and Values

## Our Mission

To provide safe and reliable energy and water services in a cost effective manner.

## Our Vision

To be a trusted leader in providing exceptional value and services to our customers and stakeholders.

Our Mission reflects our intention to continue to provide our core services in the most efficient manner possible.

WCU is both an investment and a community asset for our shareholder, the Corporation of the City of Windsor.

As an investment, our purpose is to provide stable, reliable and growing returns, and to increase shareholder value, both in the short- and long-term. We strive to be exceptional in all that we undertake on behalf of our stakeholders.

As a community asset, our goals are:

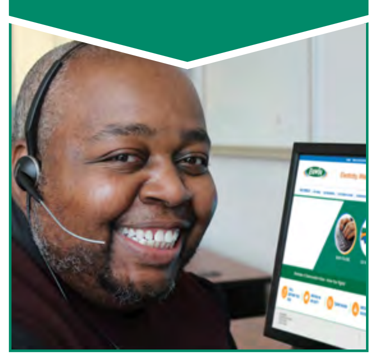
- To provide efficient and reliable services and a first-class experience to our customers; and
- To continue to be a strong strategic partner with the City, helping to deliver on its economic development and environmental agendas.

## Our Values

**LEADERSHIP**

**ACCOUNTABILITY**


**INTEGRITY**



As the energy needs and options of our customers and our community evolve — and as signature projects and developments proceed — WCU, through its affiliates, will play a leading role in helping our city to transition to a smart energy future.

We will also continue to grow shareholder value, maintaining a focus on strategic business growth within our core areas of strength. Our growth agenda involves three basic components:

- **Electricity Distribution**: Continuing to evaluate opportunities to increase our distribution service territory;
- **Energy and Related Services**: Providing innovative solutions to help consumers, businesses and communities meet their energy objectives; and
- **Utility Services**: Leveraging our assets and expertise to help other utilities to enhance the value they provide, creating new revenue streams and economies of scale, and in cooperation with WUC through our water division, reaching an increasing number of customers with our award-winning water.

Taken as a whole, we believe a strategy that builds on our vision for the company's future presents a balanced program for solid performance, adaptation to a changing business environment and sustainable and profitable business growth.

## We value leadership, accountability and integrity.

WCU and its affiliates (together – The ENWIN Group) are committed to the organizational values of leadership, accountability and integrity. These values are reflected in our Employee Code of Conduct and Conflict of Interest Policy, our organizational structure and our transparent reporting of results and challenges.

Our Boards of Directors and our Senior Management Team support an environment that fosters and demonstrates ethical business conduct at all levels and reflects these shared values. Every employee must lead by example.

## We are considerate of all stakeholders.

WCU and its affiliates take into account the interests of all our stakeholders, including employees, customers, suppliers, our shareholder and the communities and environment in which we operate.

## We put our customers first.

Our continued success depends on the quality of our customer interactions, and we are committed to delivering value across the entire customer experience.

# Mission, Vision and Values

We are honest, open and fair in our relationships with our customers. We provide reliable, responsive and innovative products and services in compliance with legislated rights and standards for access, safety, health and environmental protection.

## We value our employees.

The quality of our workforce is our strength. We will strive to hire and retain the best qualified people available and maximize their opportunities for success.

We are committed to maintaining a safe, secure and healthy work environment, enriched by diversity and characterized by open communication, trust and fair treatment.

## We value fair, honest relationships.

We are honest and fair in our relationships with our suppliers and contractors. We purchase equipment, supplies and services on the basis of merit, utilizing our professional procurement policy.

We pay suppliers and contractors in accordance with agreed terms, encourage them to adopt responsible business practices, and require them to adhere to our health, safety and environment standards when working for The ENWIN Group.

## We respect community and the environment.

We are committed to being responsible corporate citizens and will contribute to making the communities in which we operate better places in which to live and do business.

We are sensitive to the community's needs and dedicated to protecting and preserving the environment in which we operate.

## We are accountable.

We are financially accountable to our shareholder and to the institutions that underwrite our operations. We communicate to them all matters that are financially material to our organization.

We protect our shareholder's investment and manage risks effectively. We communicate to our shareholder all matters that are material to an understanding of financial position.

**ENWIN is a proud supporter of the Farrow Riverside Miracle Park.**

# Five Areas of Focus


## Strategic Objectives

The ENWIN Group's strategic themes fall into five areas of focus: Customer Service, People & Culture, Quality & Innovation, Organizational Sustainability and Community & Partnerships.

These five key areas of focus are supported by objectives that guide our activities through the current plan and form the basis of our annual reporting in the pages that follow. The Customer Service pillar always assumes the central position, as the most important driver of our business strategy.

## Customer Service Focus

We will deliver exceptional value to our customers, by:

- Committing to the safe and reliable delivery of cost effective power and water services;
- Engaging and informing our customers about our business and its impact on them; and
- Understanding customer expectations, then defining, measuring and improving our service excellence, responsiveness and customer satisfaction.

## People & Culture

We will provide a safe workplace with diverse, highly skilled and engaged employees by:

- Striving consistently for the highest health and safety standards and performance, for our employees and the public;
- Retaining, recruiting and developing the right people in the right roles and ensuring they deliver their best;
- Providing opportunities for staff to develop and grow into the leaders of tomorrow; and
- Fostering a culture of high performance, initiative and accountability.

## Quality & Innovation

We will achieve operational excellence by:

- Championing continuous improvement, including technical innovation, productivity and cost performance throughout the organization;
- Planning and investing prudently to meet the future needs of our customers;
- Measuring and acting on best-practice metrics for reliability and quality; and
- Recognizing and rewarding innovation, responsiveness and leadership.

## Organizational Sustainability

We will create sustainable performance, as well as owner and stakeholder value by:

- Developing, implementing and monitoring plans to achieve long term operational efficiencies and system reliability;
- Continually enhancing processes to maintain a financially viable organization;
- Ensuring effective governance and leadership;
- Planning for succession and developing and transferring knowledge;
- Defining, measuring and achieving targets; and
- Safeguarding private data and system security from unauthorized access.

## Community & Partnership

We will support the success of our community by:

- Contributing to our customers' and other stakeholders' economic development opportunities;
- Collaborating and partnering strategically with other organizations to drive operational excellence, productivity and innovation; and
- Delivering on our obligations mandated by the government, including educating the community to promote conservation and protecting resources.

# Our Strategic Plan

In late 2016, WCU and its affiliates updated their strategic plan for 2017-2022, with a primary goal of centering our business around the customer. Customer centrality continues to drive our business strategy.

We believe that a sharp focus on the value we provide to our customers will generate positive results in all areas of performance — our financial strength and business growth, our operational efficiency and effectiveness, and our contributions to the well-being of our community.

A core premise of our 2017-2022 Strategic Direction is that the electricity service model is in the midst of significant transformation — taking on a more decentralized, customer-centric, technologically advanced and environmentally sustainable form.

The transition to a more customer-driven and customer-centric model in the electricity sector will present opportunities for energy providers that are able to innovate — and challenges for those that fail to adapt.

In mid-2017, our senior management team reviewed the external environment and developed our strategy for responding to this emerging landscape.

This strategy consists of ten core elements, as it pertains to the electricity business:

- Taking customer experience to the next level by creating a customer value map including all customer groups;
- Enhancing our service offerings through self-service or mobile application options;
- Achieving a top quartile health and safety index recognition;
- Ensuring our employees are engaged — that they are, and remain, high performing ambassadors who embrace the change and disruption in our industry;
- Demonstrating continuous improvement in service quality;
- Developing a new product roadmap;
- Ensuring we maintain a positive brand;
- Undertaking an active Enterprise Risk Management (ERM) process to address top organizational risks;
- Defining and achieving long term ROI targets;
- Enhancing the shared services/cooperative model of achieving efficiencies through economies of scale.

In addition, the management team adopted two strategic initiatives for our water services division:

- Security of water system;
- Regional water system expansion and integration of services and supply.

The Boards of Directors of the ENWIN Group of Companies (WCU, EWU, EWE), plan to meet again in 2019 in order to provide a mid-cycle review of this strategy and to affirm, or update, the direction of the companies. As always, our strategy must continue to evolve in our changing environment.

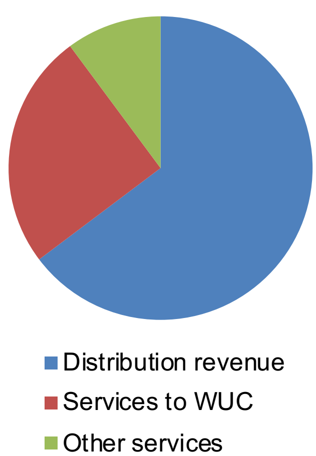
**Our skilled Powerline Maintenance Technicians ensure efficient and reliable operation of our grid.**


ENWIN crews are ready to react when repairs to our distribution system infrastructure are required.

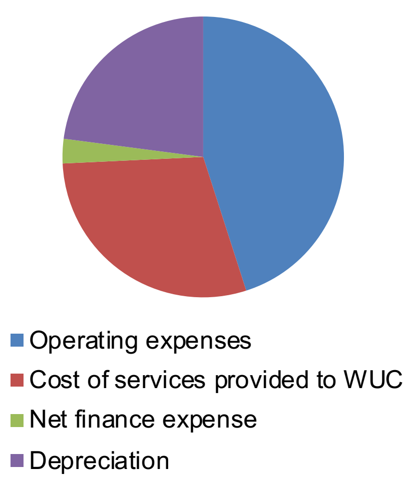
# Financial Highlights

| (in thousands of dollars) | 2018 | 2017 |
|---|---|---|
| **Operations** | | |
| Total revenue | 328,283 | 331,160 |
| Distribution revenue | 51,866 | 49,795 |
| EBITDA | 26,930 | 26,572 |
| Net Income | 8,459 | 7,930 |
| Dividends | 4,000 | 5,000 |
| **Balance Sheet** | | |
| Cash and investments | 49,688 | 39,491 |
| Property Plant and Equipment & Intangible Assets | 234,494 | 229,632 |
| Total Assets | 401,187 | 391,880 |
| Long-term borrowings | 102,470 | 102,457 |
| Equity | 171,682 | 161,870 |
| **Cash flows** | | |
| Operating | 30,487 | 30,991 |
| Investing | (19,518) | (19,271) |
| Financing | (3,178) | (4,178) |

Revenue by Type [1]




Expenses by Type [1]




1 Excludes the sale of electricity and cost of electricity

# Management's Discussion and Analysis

## Regulation, Policy & Direction

In Ontario, the Ministry of Energy (Ministry) sets the overall policy for the energy sector, guided by relevant laws and regulations.

The Ministry oversees the IESO and the Ontario Energy Board (OEB), which regulates the energy sector as set out primarily in three statutes — the Ontario Energy Board Act, 1998 (OEB Act); the Electricity Act, 1998; and the Energy Consumer Protection Act, 2010.

The OEB Act establishes the authority of the OEB to approve and fix all rates for the transmission and distribution of electricity in Ontario and to set standards of service, conduct and reporting that must be adhered to as a condition of being licensed.

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates electricity rates for distributors using a combination of detailed Cost of Service (COS) reviews and Incentive Regulation Mechanism (IRM) adjustments.

Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts, such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecast amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

## Rates

EWU recovers its costs from customers through electricity distribution rates. These include the costs to:

- Design, build and maintain overhead and underground distribution lines, poles, stations and local transformers;
- Operate local distribution systems, including smart meters; and
- Provide customer service and emergency response.

Costs and rates vary from one distributor to another, depending on factors such as the age and condition of assets, geographic terrain and distance, population density and growth and the proportion of residential to commercial and industrial consumers.

EWU's distribution charge to its residential customers represents approximately 27 percent of the total amount the customer pays. EWU collects the entire electricity bill but keeps only this portion.

The balance of the electricity bill that is not related to distribution charges is passed on, without markup, to regulators, the provincial government and the other companies responsible for generating and transmitting electricity and managing the market system.

EWU's distribution rates are set by the OEB, based on applications submitted for rate changes. In recent years EWU has not filed a COS application and as a result its portion of the bill has remained relatively constant. Effective July 1, 2017, Ontario's Fair Hydro Plan reduced electricity bills for residential customers by an average of 25%, including the 8% HST rebate introduced in January 2017.

These reductions provided some relief for residential customer following several years of rate increases as outlined in the chart below.

## Rate Application Process

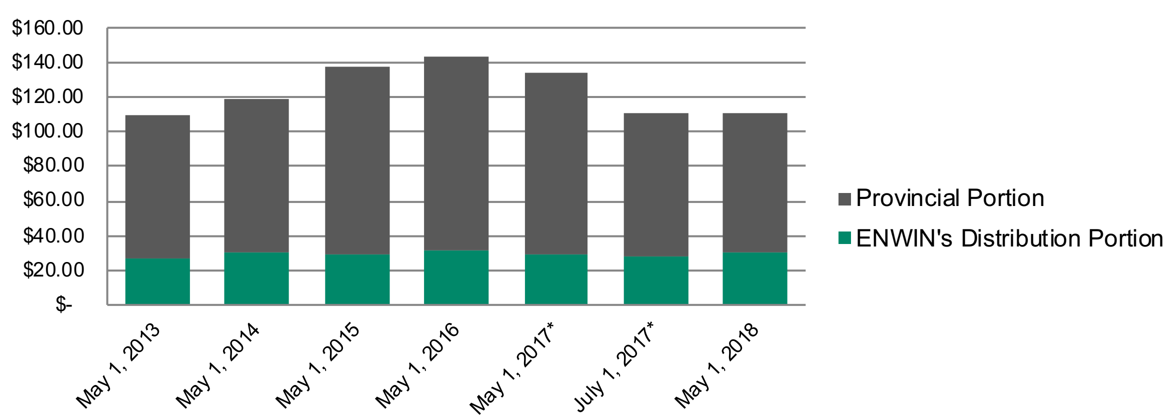
The OEB consumer-centric approach to rate applications, contained in the Renewed Regulatory Framework for Electricity (RRFE), requires LDCs to demonstrate that their services are provided in a manner that responds to identified customer needs and preferences.

Distributors are required to provide an overview of customer engagement activities they have undertaken with respect to their plans, and illustrate how customer needs and preferences have been reflected in the distributor's application.

These requirements have the effect of bringing customers directly into the process of finding the right balance between distribution costs and reliability.

The OEB does not specify how customer engagement should be accomplished, or how customer feedback should be received. However, it has encouraged utilities to use both existing and new processes.

### Total Bill for Regulated Price Plan Residential Customer (750 kWh per month usage)




*Ontario Fair Hydro Plan. 8% rebate in effect as of January 1, 2017. Revised RPP prices in effect as of July 1, 2017.

# Capability to Deliver Results

WCU's capability to achieve the objectives set out in its strategic direction is a function of its assets and expertise, both tangible and intangible, and its systems and capital resources.

## Assets

WCU's total assets are $401 million as at December 31, 2018. Its largest subsidiary, EWU, had significant ongoing investments in distribution infrastructure and technology systems in 2018.

EWU continues to be affected by the reality of aging infrastructure, which is a factor for many utilities. We continue to manage this through increased infrastructure investments and a detailed plan to target distribution system spending where it will have the most benefit.

In 2018, $19.6 million was invested to maintain and expand the distribution system and related infrastructure to meet customer needs. These investments are having the desired impact, as the company continues to maintain electricity service reliability.

## Electricity Distribution Assets

EWU and its predecessor companies have delivered a reliable supply of electricity to homes and businesses in Windsor for more than 100 years.

- Service Area ($km^2$) – 121
- Overhead Primary Circuitry (km) – 677.36
- Underground Primary Circuitry (km) – 455.59
- Bulk Transformer Stations (owned by EWU) – 5
- Feeders – 50
- Distribution Transformers – 8,260
- Station Transformers – 10

## Renewable Generation

EWU continued to help its customers contribute to the greening of the electricity supply — and reduce their electrical costs — by supporting their installation of solar panels supplying power to the grid through the Province's Feed-In Tariff (FIT) programs.

In 2018, the company connected 592 new load customers and 109 new generation customers.

## Expertise

Our focus on people and culture recognizes the importance of the people whose talent, dedication and daily work supports the vision and mission of the company.

Our success depends on a highly skilled, well trained, knowledgeable workforce and a safe, healthy work environment. Achieving the company's strategic objectives requires an environment that enables constant growth and learning, to maintain a workforce with the right skill sets to deliver on existing and new business lines.

The ENWIN Group of Companies employed 309 people at the end of 2018.

# Fast Facts

ENWIN Average Peak Load (kW)
WITH EMBEDDED GENERATION

**398,908**

ENWIN Underground Primary Circuit
KILOMETERS OF LINE

**456**

ENWIN Total Service Area (Sq. km)
URBAN SERVICE AREA

**121**

ENWIN Summer Max Monthly Peak Load (kW)
WITH EMBEDDED GENERATION

**488,900**

ENWIN Winter Max Monthly Peak Load (kW)
WITH EMBEDDED GENERATION

**362,000**

ENWIN Overhead Primary Circuit
KILOMETERS OF LINE

**677**

# Capability to Deliver Results

## Maintaining Workforce Resources

As the utility sector workforce ages, the talent and experience drain associated with significant numbers of retirements remains at the forefront for many of Ontario's LDCs.

Like many other utilities, ENWIN faces challenging workforce demographics that require a concerted response. While we employed 309 people as at December 31, 2018, the company carried approximately 20 vacancies which are expected to be filled in 2019.

Through a comprehensive and integrated talent management strategy, we are focused on anticipating and meeting talent needs, attracting and retaining the right talent, effectively deploying resources and managing the development of our staff.

This includes:

- Extensive focused, mentored, on-the-job practical training apprenticeship programs to ensure the availability of qualified journeypersons.
- Partnerships with industry and educational institutions to support the implementation of the talent management strategy. These include collaborations with St. Clair College, the University of Windsor, other institutions and contractor associations to attract and hire top flight recruits, in a variety of positions in several departments.

Most notably, sponsorship and a program delivery partnership with St. Clair College's Powerline Technician program have allowed ENWIN to draw apprentices from the ranks of its graduates in recent years.

ENWIN offers:

- Programs for succession planning and management, training and development, to ensure that there are qualified employees in the talent pipeline for key positions;
- A staffing initiative to properly equip a segment of staff with the diverse, enhanced skills to support and work in both overhead and underground environments;
- A Diversity Plan, which fosters an inclusive culture that leverages diversity and enhances employee engagement and innovation.

ENWIN's employee compensation programs continued to support a culture that values high performance, and include market-driven and performance-based components to attract, retain and reward employees who assist ENWIN's culture of continuous improvement.

## Health and Safety

At the ENWIN Group, safety is embedded within our organizational culture. It is a fundamental component of our commitment to the tremendous value of our employees, as well as operating efficiently and effectively. We place a very high priority on protecting the health and safety of our employees and our community, and we are committed to ensuring everyone returns home safely at the end of each work day.

ENWIN seeks to educate our employees and to provide a foundation for continuous improvement initiatives that will help to develop, monitor and advance our goal of zero accidents and injuries.

We believe that an effective Health & Safety Management System (HSMS) is the key to a safe workplace — and that ongoing commitment, participation and endorsement from our leaders is paramount to our success.

To that end, ENWIN has adopted the Infrastructure Health and Safety Association (IHSA) Certificate of Recognition (COR™) health and safety management system, a framework to manage risks, establish controls and minimize the incidence of injury and illness to employees.

By achieving COR™, ENWIN is able to demonstrate that our health and safety management system has been developed, implemented, and evaluated on an annual basis through comprehensive internal and external audits.

ENWIN received a Letter of Good Standing for the Certificate of Recognition (COR™) with an audit score of 93%.

We continue to be successful in strengthening our health and safety management system, reducing accidents and incidents and in our efforts to reduce lost time across the organization, coming in well below target for the last two years.

Through continuous education and training, we aim to ensure our employees are conducting their activities in a manner that makes health and safety a primary part of their daily activities.

At the ENWIN Group, our goal is to take a proactive approach to identifying risks and preventing safety issues before they occur, and to take immediate corrective action when a safety issue is identified.

## Systems and Processes

The ENWIN Group continued to make significant investments in capital and maintenance in 2018, to enhance the company's effectiveness and to ensure the utility's assets are well maintained and positioned for the future.

More than $19.6 million in capital investments supported the distribution grid and its ability to serve customers. Of this,

- $5.4 million was dedicated to replacing portions of the grid that had reached their end-of-life; and
- The $14.2 million balance was spent connecting new customers, enhancing the resiliency of the grid and maintaining buildings, fleet and systems used to serve customers.

The security of our critical infrastructure and the protection of our customers' data is a serious matter, and we work proactively with security experts in the private and public sectors.

We participate in threat information exchange and collaborate with government, regulators and other utilities to assess and manage risks and to advance progress on the OEB's recommended cybersecurity targets.

Our technology decisions continue to be based on three basic considerations:

- Enhancing service to our customers;
- Creating efficiencies that will increase our competitiveness; and
- Improving agility and resilience in the face of industry disruption.

# Community Support Program

## A powerful partner to the community.

In 2018, ENWIN continued to reach out to residents and organizations in Windsor, as a partner in supporting the health, wellbeing, future planning, innovation and lifestyle of our community.

A team of ENWIN volunteers from various departments across the company formed a Community Support Committee that helped to identify potential partnerships of value to the community and set the framework within which our employees could volunteer, fundraise and support. The committee met in late 2017 to review applications from community organizations and determine the plan for 2018.

ENWIN's key partnerships in 2018 supported health and wellness, safety, education, conservation, youth, leisure and arts.

In addition, ENWIN supported its employees' grassroots fundraising and volunteer efforts through organizations that keep our community strong, healthy and vibrant. We also partnered with local and provincial media outlets, who helped us to tell the stories of our community support and enlist public support for our employees' efforts.

In total, we partnered with 54 internal and external partners in media, education, social services, technology, community support, health and safety, lifestyle, conservation, customer service and communications, with employees volunteering 343 times, at 52 community events during the year.

Page 34 contains a list of the community, media, sector and internal partners who worked together to support our community, through ENWIN's Community Support program in 2018.

**Conservation Partners:**
- Caesars Windsor
- City of Windsor
- Essex Region Conservation Authority

**Diversity & Equality Partners:**
- Belleview Conservancy
- Windsor Pride
- Build A Dream

**Education & Innovation Partners:**
- Institute for Diagnostic Imaging Research
- Junior Achievement S/W Ontario
- St. Clair College
- University of Windsor
- WEtech Alliance
- Windsor Public Library
- Windsor Regiment Association (RCAC)

**Future Building Partners:**
- City of Windsor
- Habitat for Humanity
- United Way Windsor Essex County

**Health & Safety Partners:**
- Canadian Cancer Society Windsor
- Downtown Mission Windsor
- John McGivney Children's Centre
- Maryvale Adolescent & Family Services
- Ronald McDonald House Windsor
- Windsor Fire & Rescue Services
- Windsor Police Services
- Windsor Regional Hospital

**Internal Partners: The Powerful Partner Within**
- Community Support Committee
- Corporate Communications
- Customer Service Department
- CDM Department
- Employee Volunteers
- Human Resources Department
- Hydro Operations Department
- System Operations Centre
- 136 Volunteers
- Water Operations Department
- Windsor Utilities Commission

**Diversity & Equality Partners:**
- Riverside Miracle Park
- Rotary Club of Windsor 1918
- Windsor Essex Economic Development Corp.
- Windsor Essex Community Foundation
- Windsor Spitfires Hockey Team

**Sector Partners:**
- Essex Powerlines

**Story Distribution Partners:**
- EDA Distributor
- Globe & Mail
- Ontario Regional Common Ground Alliance
- Windsor Life Magazine
- Windsor Chamber of Commerce
- Bell Media CKLW AM 800
- Blackburn Radio News
- CBC TV News Windsor
- CBC Radio Windsor
- CTV News Windsor
- Windsor Star
- windsorite.ca
- OurWindsor.ca
- Windsor Life Magazine


**ENWIN Superheroes took to the skies at community events providing children and families a unique vantage point.**

# Results - Progress Against the Plan

WCU's Strategic Direction ensures that the utility will continue to build towards achieving strategic objectives in each of its five areas of focus.

The next five pages summarize its performance towards these goals in 2018.

# Results - Progress Against the Plan

## Key Area of Focus: Customer Service

**Strategic Objective**: We will deliver exceptional value to our customers.

| Performance Commitment | 2018 Performance Highlights |
|---|---|
| Deliver safe, reliable, cost effective services<br><br>Engage and inform our customers<br><br>Measure and define customer expectations<br><br>Improve customer satisfaction | • Updated Conditions of Service that describe the operating practices, connection policies and the types of service available to customers within ENWIN's service area.<br>• Established corporate-wide Customer Service Standards.<br>• Upgraded CIS Northstar.<br>• Took part in SAP CIS consortium study.<br>• Gauged customer opinion through an annual customer survey.<br>• Surveyed customers to assess knowledge of electrical safety.<br>• Connected 592 new load customers.<br>• Processed more than 300 applications for conservation incentives, representing a local investment of over $16 million, with incentives of $2.6 million going back to customers.<br>• Despite repeated adverse weather events, the average duration of outages was maintained at less than a half hour.<br>• Responded to more than 650 streetlight out calls.<br>• Supported customer events, such as Chrysler kids Environmental Artwork Program, St. Clair College Awards Night, University of Windsor Scholarship Awards, Caesars Windsor's Earth Hour Celebration, University of Windsor's IDIR NSERC initiative and Windsor Public Library's Rain Garden Initiative.<br>• Supported energy conservation organizations, such as the Association of Energy Engineers –Southwestern Ontario Chapter. |

## Key Area of Focus: People & Culture

**Strategic Objective**: We will provide a safe workplace with diverse, highly skilled and engaged employees.

| Performance Commitment | 2018 Performance Highlights |
|---|---|
| Attain consistent, high health and safety standards<br><br>Retain, recruit and develop talent<br><br>Provide growth and leadership opportunities<br><br>Foster a culture of high performance, initiative and accountability | • Received a Letter of Good Standing for the Certificate of Recognition (COR™) with an audit score of 93%.<br><br>• We continue to be successful in our efforts in reducing lost time across the organization, coming in well below target for the last two years.<br><br>• Delivered extensive in-house apprenticeship programs, engineering and business internships, ensuring availability of qualified future employees.<br><br>• Partnered with industry and educational institutions to support talent attraction and recruitment.<br><br>• Put in place a Diversity Plan to foster an inclusive culture.<br><br>• Held consultations with staff to develop the vision for the Diversity Plan.<br><br>• Launched the ENWIN NEWS NETWORK (ENN) to provide access to internal and external news for employees, via large digital screens.<br><br>• Created a video series to engage employees and capture the positive challenges and experiences associated with their roles, both as employees and volunteers.<br><br>• "What's Powerful to You" employee survey engaged employees in voicing positive thoughts about employment with ENWIN, which were later shared by video and email. |

# Results - Progress Against the Plan

## Key Area of Focus: Quality & Innovation

**Strategic Objective**: We will achieve operational excellence.

<table>
<tr><th>Performance Commitment</th><th>2018 Performance Highlights</th></tr>
<tr><td>Improve technical innovation, productivity and cost performance<br><br>Plan and invest prudently to meet future needs<br><br>Measure and achieve best-practice reliability and quality<br><br>Recognize and reward innovation & leadership</td><td>• Invested $19.6 million in its capital program in support of the distribution grid and its ability to serve customers:<br>    • Invested $5.4 million in replacing aging grid<br>    • Invested $14.2 million balance in connecting new customers, maintaining buildings, enhancing the resiliency of the grid, fleet and systems used to serve customers<br><br>• Successfully completed its 2018 ESA audit cycle, obtaining full compliance with Regulation 22/04, with no ‘non-compliance’ or ‘needs improvements’ areas identified.<br><br>• Continued working with communications companies to share infrastructure providing Windsor residents with high speed fibre-optic communication links.<br><br>• Established ONtech Rapid Coatings Inc. and advanced the use of cold spray technology to perform on-site repairs to transformers and switch enclosures, extending the life of those devices and lowering costs for customers.<br><br>• “ENnovation” program offered front line employees an opportunity to develop innovations that would impact organizational stability.<br><br>• Powerful Partners magazine stories and news releases gave public recognition to employee expertise, ingenuity, leadership and commitment.<br><br>• ENWIN Superheroes campaign offered public and internal recognition employees for leadership in philanthropy.</td></tr>
</table>

## Key Area of Focus: Organizational Sustainability

**Strategic Objective**: We will create sustainable performance, as well as owner and stakeholder value.

| Performance Commitment | 2018 Performance Highlights |
|---|---|
| Develop and implement plans for long-term efficiency and reliability<br><br>Enhance processes to maintain financial viability<br><br>Ensure effective governance and leadership<br><br>Define, measure and achieve targets<br><br>Safeguard private data and system security | • Prepared for 2020 Cost of Service Rate Application.<br>• Commenced negotiations to renew our streetlight contract with the City of Windsor.<br>• Revised procedures for theft of service.<br>• Continued governance review.<br>• Installed first gross load billing customer.<br>• Extended Hydro SMART meters life.<br>• Continued site consolidation work.<br>• Continued property remediation to prepare for the future sale of three 4kV substations.<br>• Leveraged membership with the GridSmartCity© cooperative to realize cost savings through joint tendering for electrical distribution system equipment.<br>• Through membership in Utility Standards Forum (USF) cooperative, shared information related to effectiveness and efficiency.<br>• Returned a $4 million dividend to our shareholder<br>• Continued corporate metrics measurements and benchmarking achievements.<br>• Ensured clear communication of corporate direction through ongoing policy and procedure review. |

# Results - Progress Against the Plan

## Key Area of Focus: Community & Partnership

**Strategic Objective**: We will support the success of our community.

| Performance Commitment | 2018 Performance Highlights |
|---|---|
| Contribute to local economic development<br><br>Collaborate strategically to drive excellence, productivity and innovation<br><br>Educate the community to conserve and protect resources. | • Partnerships in education offered programming, internships, cooperative work terms and summer job learning experiences to students, most notably:<br>• St. Clair College, Marketing Program<br>• St. Clair College Powerline Technician Program<br>• University of Windsor School of Business<br>• University of Windsor Engineering Program<br><br>• 145 employees volunteered, resulting in 343 distinct appearances by ENWIN employees at 52 partner events and fundraisers in 2018.<br><br>• Supported 12 key partner organizations representing health, education, conservation, innovation, and community lifestyle – six identified by our Community Support Committee and six brought forward by individual ENWIN employees as 'grass roots' fundraising projects.<br><br>• Partnered with 19 other local organizations, to volunteer at events and raise awareness. For a list of our 2019 partners, see Community Support on page 34.<br><br>• Promoted public safety and awareness through ENWIN Safety Powerplay Partnership with Windsor Spitfires<br><br>• Worked with Windsor Detroit Bridge Authority towards completion of electrical infrastructure for the Canadian plaza to connect local highways with the new Gordie Howe International Bridge between Detroit and Windsor. |


**ENWIN's partnership with St. Clair College led to the development of a pilot project employing students for pole inspection.**

# Financial Results

The selected consolidated financial results of the Corporation, presented below, should be viewed in conjunction with the audited consolidated financial statements and accompanying notes for the year ended December 31, 2018.

Windsor Canada Utilities Ltd. (WCU) has two wholly owned subsidiaries: ENWIN Utilities Ltd. (EWU) and ENWIN Energy Ltd. (EWE). The consolidated financial statements of WCU are a direct result of the activities generated by these two entities. EWU is the regulated Local Distribution Company that provides electricity and related utilities services to over 89,000 residential and business customers.

EWU and the Windsor Utilities Commission entered into a Water System Operating Agreement (WSOA) in 2012 under which EWU provides utility services to WUC.

EWE provides streetlight maintenance for the City of Windsor.

The statements are presented utilizing International Financial Reporting Standards (IFRS), as adopted by WCU initially in 2012. At the time of adoption, IFRS 14 – Regulatory Deferral Accounts was not available to EWU, and remains unavailable for EWU.

Accordingly, these statements do not reflect recognition of the regulatory deferral accounts. Regulatory deferral accounts are prescribed by the OEB for tracking revenues and expenses that are subject to the rate setting process for EWU.

## Consolidated Statement of Income (Summary)

(in thousands of dollars)

| | 2018 | 2017 | Change |
|---|---|---|---|
| Revenue from the sale of electricity | 249,432 | 254,223 | (4,791) |
| Cost of electricity purchased | 252,700 | 255,421 | (2,721) |
| Net revenue (expense) from the sale of electricity | (3,268) | (1,198) | (2,070) |
| Distribution revenue | 51,866 | 49,795 | 2,071 |
| Other revenue | 26,985 | 27,142 | (157) |
| Net revenue | 75,583 | 75,739 | (156) |
| Operating Expenses | | | |
| Operating and distribution expenses | 33,582 | 33,593 | (11) |
| Billing, collecting and administrative expenses | 15,071 | 15,574 | (503) |
| | 48,653 | 49,167 | (514) |
| Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA) | 26,930 | 26,572 | 358 |
| Depreciation expense | 14,009 | 13,461 | 548 |
| Net finance expense | 1,427 | 1,653 | (226) |
| Income before tax | 11,494 | 11,458 | 36 |
| Income tax | 3,035 | 3,528 | (493) |
| Net Income | 8,459 | 7,930 | 529 |

Any variances between the Revenue collected and cost for electricity is settled in subsequent years through regulatory rate adjustments.

Since these accounts cannot be utilized in these financial statements, revenue and expenses associated with the sale and cost of electricity are recognized on a cash basis. This results in earnings volatility when the settlement of differences between what EWU charges its customers for the cost of power and what it pays the provincial electrical system operator takes place over more than one year.

For rate setting purposes the sale and cost of electricity is a flow-through item for which, over the long term, any net revenue or expenses resulting from the sale and cost of power are ultimately returned or charged to EWU's customers as mandated by the OEB. Accordingly, the operating results of EWU are typically viewed in absence of these amounts by the regulator and the company.

## Net Income

Net income in 2018 was $8.5 million compared to $7.9 million in 2017. Despite the potential for timing differences related to the cost of power, net income was very comparable to the prior year and provides for a 5.1% return on equity.

## Sales and Costs of Electricity

In 2018, revenue from the sale of electricity of $249.4 million was $4.8 million less than in 2017. At the same time the cost of electricity paid by EWU decreased by just $2.7 million. The combined difference in these changes had the effect of positively impacting earnings in 2018 compared to 2017 in the amount of $2.1 million.

The reduction in revenue from the sale of electricity in 2018 was due to Ontario's Fair Hydro Plan, which provided for reduced time-of-use electricity rates for the majority of Ontario's residential and small commercial customers starting in May and July 2017.

The summary of historic time-of-use rates presented below illustrates the reduction of the average time-of-use rate from 13.30 cents per KWh in 2016 to 9.70 cents per KWh in July 2017 and this generally continued into 2018.

### Historical Time-of-Use Electricity Rates

| Effective date | Off-peak price (¢ per kWh) | Mid-peak price (¢ per kWh) | On-peak price (¢ per kWh) | Average (¢ per kWh) |
|---|---|---|---|---|
| 1-May-18 | 6.5 | 9.4 | 13.2 | 9.70 |
| 1-Jul-17 | 6.5 | 9.5 | 13.2 | 9.73 |
| 1-May-17 | 7.7 | 11.3 | 15.7 | 11.57 |
| 1-Nov-16 | 8.7 | 13.2 | 18.0 | 13.30 |
| 1-May-16 | 8.7 | 13.2 | 18.0 | 13.30 |
| 1-Nov-15 | 8.3 | 12.8 | 17.5 | 12.87 |
| 1-May-15 | 8.0 | 12.2 | 16.1 | 12.10 |
| 1-Nov-14 | 7.7 | 11.4 | 14.0 | 11.03 |
| 1-May-14 | 7.5 | 11.2 | 13.5 | 10.73 |
| 1-Nov-13 | 7.2 | 10.9 | 12.9 | 10.33 |
| 1-May-13 | 6.7 | 10.4 | 12.4 | 9.83 |

# Financial Results

## Distribution revenue

While the sale of electricity is a flow through cost for EWU, distribution charges on EWU customer bills become revenue for the Company to cover its operating and capital costs.

The rates used to establish distribution charges to EWU customers are set by the OEB. In 2018, distribution revenue of $51.9 million was $2.1 million, or 4.2% higher than in 2017.

In 2018, as in recent years, EWU's rate applications to the OEB have provided for below inflation rate increases and accordingly the distribution portion of our customers' bills has increased by just 35 cents per month since May 2014, and is 45 cents less per month than in May 2016.

### Distribution portion of a Monthly Electric Bill for a Regulated Price Plan Residential Customer (750kWh per month usage)

| May 1, 2014 | May 1, 2015 | May 1, 2016 | May 1, 2017 | May 1, 2018 |
|---|---|---|---|---|
| $ 30.22 | $ 28.78 | $ 31.02 | $ 29.32 | $ 30.57 |

## Other Revenue

Other revenue for WCU includes amounts charged to WUC by EWU under the Water Services Operating Agreement, together with charges to the City of Windsor for streetlight maintenance and sewer surcharge billing and collection services, and other miscellaneous items detailed in note 19 of the audited financial statements.

In 2018, services provided to WUC increased by $0.7 million to $20.0 million. Other income items attributable primarily to services provided to the City of Windsor decreased by $825 thousand during the year.

The reduction in other income was attributed to disposal of long term assets and lower tax credits for research and development activities.

## Operating Expenses

Overall operating expenses, including depreciation and amortization, remained consistent at $62.7 million in 2018.  Reductions in billing, collecting and administrative expenses were offset against increases in depreciation and amortization.

## Depreciation and Amortization

Depreciation and amortization on WCU's property, plant, equipment and intangible assets increased in 2018 by $548 thousand to $14.0 million, primarily due to the ongoing investment in, and expansion of, the Corporation's electricity distribution infrastructure.

## Net Finance Expense

Net Finance expense of $1.4 million includes interest expense of $4.3 million on the company's $103 million senior unsecured debentures, which are due in 2042. The interest expense is offset by interest income from WUC of $2.15 million for its share of the senior unsecured debenture, $236 thousand earned on the company's sinking fund investments and $556 thousand earned on bank balances.

## Consolidated Balance Sheet (Summary)

| (in thousands of dollars) | 2018 | 2017 | Change |
|---|---|---|---|
| Current assets | | | |
| Cash and short term investments | 41,869 | 32,961 | 8,908 |
| Accounts receivable and other current assets | 56,056 | 57,548 | (1,492) |
| Total current assets | 97,925 | 90,509 | 7,416 |
| Property, plant and equipment & intangible assets | 234,494 | 229,632 | 4,862 |
| Other non current assets | 68,768 | 71,739 | (2,971) |
| **Total Assets** | 401,187 | 391,880 | 9,307 |
| Current liabilities | 42,272 | 39,046 | 3,226 |
| Long term debt | 102,470 | 102,457 | 13 |
| Other non-current liabilities | 84,763 | 88,507 | (3,744) |
| Total liabilities | 229,505 | 230,010 | (505) |
| Equity | 171,682 | 161,870 | 9,812 |
| **Total Liabilities and Equity** | 401,187 | 391,880 | 9,307 |

# Financial Results

## Assets

Total assets increased by approximately $9.3 million to $401.2 million during 2018. This increase is mainly due to the increase in cash and short-term investments from $33.0 million to $41.9 million. This increase is partially a result of an increase in funds received for conservation activities, which will be paid to customers in the future.

Other non-current asset balances increased by $1.9 million primarily as a result of the planned increase in the sinking fund investment and increases in property, plant and equipment, offset by a decrease in deferred tax payable.

## Liabilities

Total liabilities were virtually unchanged versus 2018. The largest liability of WCU is the $103 million senior debenture. $52 million of the proceeds from the issuance of the debenture were loaned to WUC, which pays its share of the annual interest costs to WCU, and has provided a guarantee to WCU in support of its ultimate repayment of these funds, reducing the overall exposure of WCU on this debt. This balance is not due until 2042, and funds are currently being set aside in a sinking fund to facilitate repayment.

Current liabilities increased by $3.2 million, primarily as a result of an increase in deferred revenue. Conservation funding was received at the end of 2018 and was not yet utilized, resulting in a higher deferred tax balance and also a higher cash balance, as described previously.

The decrease in other non-current liabilities is primarily a result of actuarial revaluations on the employee future benefits liability, which decreased from $68.4 million to $64.4 million. The employee future benefits liability is sensitive to interest rate changes and is expected to be volatile over the next several years.

## Consolidated Statement of Cash Flows (Summary)

| (in thousands of dollars) | 2018 | 2017 | Change |
|---|---|---|---|
| Cash and cash equivalents, beginning of year | 27,949 | 20,407 | 7,542 |
| Cash provided by Operating activities | 30,487 | 30,991 | (504) |
| Cash used in Investing activities | (19,518) | (19,271) | (247) |
| Cash provided (used) by Financing activities | (3,178) | (4,178) | 1,000 |
| Cash and cash equivalents, end of year | 35,740 | 27,949 | 7,791 |

## Operating Activities

Cash increased during the year as a result of continued strong operating performance.

## Investing Activities

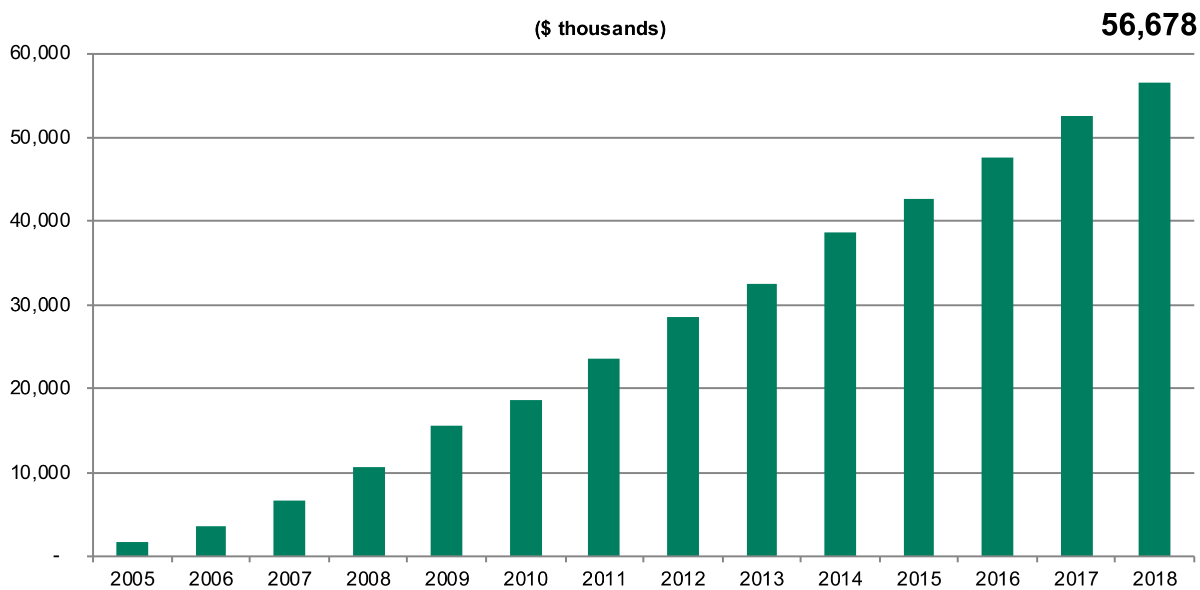
Cash used in investing activities was $19.5 million compared to $19.3 million in the prior year. Investing activities includes $19.6 million of capital expenditures, versus $15.6 million in 2017, offset by contributed capital expenditures targeting system renewal, technological advances and accommodating new customer growth. During the year the company also invested further in its sinking fund and short term GIC's in the amount of $2.2 million.

## Financing Activities

Financing activities include dividends paid to the City of Windsor along with changes in related party balances. The dividend payment to the City of Windsor of $4 million is in accordance with the target.

The company has paid cumulative dividends to the City of Windsor since 2005 of $56.7 million.

### Cumulative Dividends to the City



# Risks and Uncertainties

Windsor Canada Utilities Ltd. has adopted a systematic approach to the management of risks and uncertainties, integrating risk management into business processes and the periodic reporting of organizational performance.

The Corporation's Enterprise Risk Management (ERM) framework was established by the Board in 2017 and is to be renewed annually. It consolidates semi-annual risk reporting to the President and Chief Executive Officer and to the Board, highlighting potential risk factors that may have an impact upon ENWIN's near-term business objectives and strategic direction.

The ERM framework supports and compliments WCU's strategic planning and annual business planning cycles, thereby enabling continuous review of assumptions and regularly refreshed environment scans.

WCU monitors sources of risk inherent in the industry and to the regulated environment. These include, but are not restricted to:

- The political and regulatory environment;
- The state of the economy and macro-economic trends;
- The state of financial markets and of investment in the utilities space;
- Government policies relating to the production and procurement of renewable and clean energy, as well as carbon emissions and conservation;
- The convergence of information technology and operational technology;
- Labour force demographics, with a particular emphasis on the renewal of human resources in the trades; and
- The weather.

In combination, these sources of risk will shape the evolution of the industry, which could in turn present new and emerging risks that need to be managed effectively.

## Policy and Regulatory Change

On January 31, 2018, the OEB released its implementation plan for Ontario's Long-Term Energy Plan (LTEP).

Key to the implementation plan are:

- Assessment of reforms to promote greater efficiency and innovation;
- Definition of a new plan for rate regulation;
- Identification of barriers to the development of distributed energy resources; and
- Review and refinement of approaches to the price consumers pay for electricity.

It is uncertain at this time what the implementation of the LTEP will mean for the setting of future rates for EWU, and if the Company will have the necessary scope and scale of operations to effectively address the pending changes required to the grid.

Political policy changes resulting from the June 2018 provincial election have started to impact the business model of the Company.

## Regulator Rate Setting Environment

ENWIN's electricity distribution business is in the process of seeking approval from the Ontario Energy Board (OEB) for a re-basing of its distribution rates, having last done so in 2009. The Company is subject to the risk that the OEB will not approve the Company's distribution revenue requirements requested in future rates.

EWU's ability to recover the actual costs of providing services and earn the allowed ROE depends on the Company achieving its forecasts, established in the rate setting process. If actual loads and energy consumption vary substantially from forecast, or if actual costs of operations, maintenance, administration, capital and financing materially deviate from projections included in the approved revenue requirements, EWU may not achieve its desired level of returns.

Electricity distribution is a capital intensive business. As EWU continues to invest in the renewal of existing aging infrastructure and the development of new infrastructure to address the changing technological needs of distributed electricity, there is no assurance that it will receive the necessary funding in rates from the OEB. To mitigate this risk, the Company strives to stay informed of OEB policy and decisions related to these matters.

## LDC Consolidation in Ontario

Consolidation amongst municipally-owned LDCs continues to be encouraged at the provincial level, as an opportunity to attain economies of scale that would work to the benefit of the customers of all the participating utilities.

However, the pursuit of this opportunity may not be viable if valuations for mergers and acquisitions remain at levels that utilities may consider excessive or potentially detrimental to their own interests, or those of the shareholder and ratepayers.

The possibility of voluntary consolidation or collaboration with like-minded municipally-owned LDCs for mutual benefit exists if policy direction, regulatory guidance and tax incentives were appropriately aligned.

EWU has formed strategic alliances with other utilities through membership in organizations such as GridSmartCity® and the Utility Standards Forum (USF), that offer an alternative to consolidation, by working together to find efficiencies through partnership. Failure to achieve economies of scale has been viewed as an enterprise risk by WCU with mitigation strategies as described.

## Changing Demand for Electricity Distribution Services

As costs decline for energy generation and storage technologies, the LDC's customers may move progressively towards cost-competitive alternatives, thereby reducing customer need for, and dependence on, the grid. Should these trends materialize at a significant scale, policy and regulatory changes will be necessary in order for ENWIN to recover its investment in infrastructure.

# Risks and Uncertainties

The role of the LDC through this change may differ and require further investment in technology and change in the nature of services provided by the LDC. Failure to adapt to the changing technologies, and failure to invest in innovation or new business services, may impact the business model of the Company.

Conversely, if policies and programs to respond to climate change accelerate the adoption of electric vehicles, the timing and level of demand for electricity may change significantly, resulting in changes to infrastructure needs and continued rate setting evolution.

## Pension Plans

The Company provides a defined benefit pension plan for the majority of its employees through the Ontario Municipal Employees Retirement System (OMERS).

Any future funding shortfalls and net losses at OMERS are subject to the OMERS Sponsors Corporation Funding Management Strategy, which outlines how benefits and contributions will be modified as the OMERS Primary Plan cycles through periods of funding deficit and surplus.

Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets.

There is no assurance that pension plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual returns on pension plan assets.

## Technology Infrastructure

WCU’s business relies on complex information systems, covering operational software, as well as back office processes.

Operational systems include:

- A geographic information system;
- An outage management system; and
- An electricity system supervisory control and data acquisition system (SCADA).

Back office processes, such as customer information and billing systems are heavily integrated with thousands of smart meters producing large volumes of data which is shared with Ontario’s Smart Metering Entity.

The failure of one or more of these key systems, or a failure of the company to either plan effectively for future technology needs or to transition effectively to new technology systems, could adversely impact the business operations.

As the sector moves to develop distributed energy resources and smart grid technology, the requirement for efficient deployment of new technology increases.

WCU seeks to identify and manage such risks through rigorous technology planning and implementation of preventative and detective controls.

## Cybersecurity

WCU and its affiliates operate complex information systems including Smart Metering and SCADA networks. These systems are integrated across the electricity sector and carry growing volumes of data. The increased volume of data and integration increases exposure to information security threats, including cybersecurity risks.

Our information and operational systems and information assets could be put at risk by a security breach, data corruption or system failure at a shared resource or common service provider.

## Customer and Media Perceptions

Electricity utilities across Ontario are confronted with risks arising from negative customer and media perceptions. These relate especially to high commodity prices in the electricity sector, which are outside the control of The ENWIN Group.

Our local reputation is strong, and we are becoming recognized locally for our focus on customer value. This should enable WCU to manage the impact of customer dissatisfaction with the electricity sector at large, however the precise scope and nature of this risk factor cannot be foreseen.

WCU's subsidiary, EWU, also provides potable water production, transmission and distribution services through its water division. The potential for contaminated source water may be viewed as an additional enterprise risk.

## Labour Force Demographics

Across the electricity sector, retirements are outpacing new entrants to the workforce, which could have an adverse impact on WCU's ability to build a sustainable workforce and achieve its business objectives. This is particularly evident in field personnel.

Failure to recruit and retain talent can lead to workforce overload and knowledge gap, which may impact quality and safety.

As a significant portion of WCU's experienced workforce retires over the next decade, our continued focus on training and safety will be critical in maintaining safety and reliability across our system.

Our investments in safety programs, apprenticeships, internships, diversity, knowledge management, and succession planning are designed to manage risks relating to workforce demographics.

## Weather

Severe weather can significantly impact financial results, in part through increased capital and maintenance costs to repair or replace damaged equipment and infrastructure. Weather fluctuations also influence distribution revenues, which tend to increase with severe weather and decrease with moderate weather.

# Risks and Uncertainties

## Economy

The state of the local, national and international economies could have a significant impact on WCU's business performance, through factors such as inflation, customer credit risk, weakening demand for electricity and/or value-added services, and availability of market capital to fund growth. The economic climate could also have an effect on the stability and performance of some of EWU's key business partners.

## Outlook (Summary)

Subject to the risks and uncertainties discussed above, WCU, through its subsidiaries, will continue to provide efficient, reliable and competitively priced electricity distribution services to customers, and to provide energy and utility expertise.

It is our goal to ensure that customers will continue to benefit from stable, moderate and predictable rate impacts. In the interest of moderating future rate increases to the LDC's customers as fully as possible, WCU remains committed to ongoing innovation, productivity and cost containment.

WCU has continued to pursue expansion in non-regulated areas, including energy and utility services.

In late 2018, in partnership with Tessonics Inc., ENWIN Energy Ltd. incorporated ONtech Rapid Coatings Inc., and holds a 50% ownership in this entity.

ONtech offers solutions for surface treatment and repair, using advanced technology and customized metallic coatings. ONtech is the culmination of a productive, long-term research and development collaboration between the partners, resulting in innovative technology applications in the electricity and water sectors, but also throughout the broader energy sector, automotive and aeronautic industries.

This company offers technology that is needed in North America, to help companies extend the useful life of assets and reduce costs related to depreciation.

Both business lines will leverage existing assets and expertise to achieve commercialization of new technologies. This is expected to represent a third driver of financial strength in future years, supplementing the core distribution business and existing unregulated services.

# Financial Statements

## Windsor Canada Utilities Ltd.

Fiscal Year Ended December 31, 2018

KPMG LLP
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Canada
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# INDEPENDENT AUDITORS' REPORT

To the Shareholder of Windsor Canada Utilities Ltd.

## *Opinion*

We have audited the consolidated financial statements of Windsor Canada Utilities Ltd. (the Entity), which comprise:

- the consolidated balance sheet as at December 31, 2018
- the consolidated statement of income for the year then ended
- the consolidated statement of comprehensive income for the year then ended
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018, and its results of operations and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

## *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 ***"Auditors' Responsibilities for the Audit of the Financial Statements"*** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other 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 for the Financial Statements*

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS), 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 Entity'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 Entity or to cease operations, or has no realistic alternative but to do so.

### *Auditors' 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 auditors' 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 International Financial Reporting 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 the financial statements.

As part of an audit in accordance with International Financial Reporting 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 Entity'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 Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' 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 auditors' report. However, future events or conditions may cause the Entity 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.
- 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.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Windsor, Canada
April 17, 2019

# WINDSOR CANADA UTILITIES LTD.

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Year ended December 31, 2018

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# WINDSOR CANADA UTILITIES LTD.

Consolidated Balance Sheet
(In thousands of Canadian dollars)

December 31, 2018, with comparative information for 2017

| | Notes | | 2018 | | 2017 |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| **Current assets:** | | | | | |
| Cash and cash equivalents | 4 | $ | 35,740 | $ | 27,949 |
| Investment | 9 | | 6,129 | | 5,012 |
| Accounts receivable | 5 | | 48,666 | | 46,772 |
| Payments in lieu of income taxes receivable | 16 | | - | | 1,482 |
| Due from related parties | 22 | | 2,783 | | 3,428 |
| Inventory | 6 | | 3,749 | | 4,097 |
| Other assets | | | 858 | | 1,769 |
| | | | **97,925** | | **90,509** |
| **Non-current assets:** | | | | | |
| Property, plant and equipment | 7 | | 229,572 | | 220,934 |
| Intangible assets | 8 | | 4,922 | | 8,698 |
| Investment, sinking fund | 9 | | 7,819 | | 6,530 |
| Investment in joint venture | 23 | | 87 | | - |
| Work in progress | | | 297 | | 330 |
| Due from related parties - debentures and post-retirement | 22 | | 54,055 | | 54,877 |
| Deferred income taxes | 16 | | 6,510 | | 10,002 |
| | | | **303,262** | | **301,371** |
| **Total assets** | | **$** | **401,187** | **$** | **391,880** |
| **Liabilities** | | | | | |
| **Current liabilities:** | | | | | |
| Accounts payable and accruals | 10 | $ | 26,009 | $ | 30,444 |
| Payments in lieu of income taxes payable | 16 | | 938 | | - |
| Due to related parties | 22 | | 5,649 | | 5,219 |
| Current portion of customer deposits | 11 | | 919 | | 1,211 |
| Deferred revenue | | | 8,757 | | 2,172 |
| | | | **42,272** | | **39,046** |
| **Non-current liabilities:** | | | | | |
| Customer deposits | 11 | | 5,919 | | 7,434 |
| Deferred revenue - customer contributions | 12 | | 14,447 | | 12,681 |
| Long-term debt | 13 | | 102,470 | | 102,457 |
| Employee future benefits | 14 | | 64,397 | | 68,392 |
| | | | **187,233** | | **190,964** |
| **Total liabilities** | | | **229,505** | | **230,010** |
| **Equity** | | | | | |
| Common shares | 17 | | 81,842 | | 81,842 |
| Contributed surplus | | | 516 | | 516 |
| Retained earnings | | | 92,007 | | 87,548 |
| Accumulated other comprehensive loss | | | (2,683) | | (8,036) |
| | | | **171,682** | | **161,870** |
| Commitments and contingencies | 25 | | | | |
| **Total liabilities and equity** | | **$** | **401,187** | **$** | **391,880** |

The accompanying notes are an integral part of these consolidated financial statements.

On behalf of the Board:

Director

Director

# WINDSOR CANADA UTILITIES LTD.

Consolidated Statement of Income
(In thousands of Canadian dollars)

Year ended December 31, 2018, with comparative information for 2017

| | Notes | 2018 | 2017 |
|---|---|---|---|
| **Revenue from sale of electricity:** | | | |
| Sale of electricity | | $ 249,432 | $ 254,223 |
| Distribution revenue | **18** | 51,866 | 49,795 |
| | | 301,298 | 304,018 |
| Cost of electricity purchased | | 252,700 | 255,421 |
| **Gross profit** | | **48,598** | **48,597** |
| **Other revenue:** | | | |
| Services provided to Windsor Utilities Commission | 22 | 20,004 | 19,336 |
| Other income | 19 | 6,981 | 7,806 |
| | | **26,985** | **27,142** |
| **Operating expenses:** | | | |
| Operating and distribution expenses | | 33,582 | 33,593 |
| Billing, collecting and administrative expenses | | 15,071 | 15,574 |
| Depreciation and amortization | 7, 8 | 14,009 | 13,461 |
| | | **62,662** | **62,628** |
| **Income from operating activities** | | **12,921** | **13,111** |
| **Finance expense (income):** | | | |
| Finance income | 21 | (2,948) | (2,677) |
| Finance expense | 21 | 4,375 | 4,330 |
| | | **1,427** | **1,653** |
| **Income before tax** | | **11,494** | **11,458** |
| **Income taxes:** | | | |
| Provision for payments in lieu of corporate taxes | 16 | 1,467 | 3,867 |
| Deferred income taxes | 16 | 1,568 | (339) |
| | | **3,035** | **3,528** |
| **Income for the year** | | **$ 8,459** | **$ 7,930** |

The accompanying notes are an integral part of these consolidated financial statements.

# WINDSOR CANADA UTILITIES LTD.

Consolidated Statement of Comprehensive Income
(In thousands of Canadian dollars)

Year ended December 31, 2018, with comparative information for 2017

| | Notes | | 2018 | | 2017 |
|---|---|---|---|---|---|
| **Income for the year** | | $ | **8,459** | $ | **7,930** |
| **Other comprehensive income (loss):** | | | | | |
| Items that will not be reclassified to the statement of income: | | | | | |
| Remeasurement of employee future benefits income (loss) | 14 | | 7,283 | | (5,758) |
| Related tax | 16 | | (1,930) | | 1,526 |
| **Other comprehensive income (loss)** | | | **5,353** | | **(4,232)** |
| **Total comprehensive income for the year** | | **$** | **13,812** | **$** | **3,698** |

The accompanying notes are an integral part of these financial statements.

# WINDSOR CANADA UTILITIES LTD.

Consolidated Statement of Changes in Equity
(In thousands of Canadian dollars)

Year ended December 31, 2018, with comparative information for 2017

| | Share capital | Contributed surplus | Retained earnings | Accumulated other comprehensive loss | Total |
|---|---|---|---|---|---|
| Balance at January 1, 2017 | $ 81,842 | $ 516 | $ 84,618 | $ (3,804) | $ 163,172 |
| Income for the year | - | - | 7,930 | - | 7,930 |
| Dividends declared | - | - | (5,000) | - | (5,000) |
| Other comprehensive loss | - | - | - | (4,232) | (4,232) |
| Balance at December 31, 2017 | $ 81,842 | $ 516 | $ 87,548 | $ (8,036) | $ 161,870 |
| Income for the year | - | - | 8,459 | - | 8,459 |
| Dividends declared | - | - | (4,000) | - | (4,000) |
| Other comprehensive income | - | - | - | 5,353 | 5,353 |
| Balance at December 31, 2018 | $ 81,842 | $ 516 | $ 92,007 | $ (2,683) | $ 171,682 |

The accompanying notes are an integral part of these consolidated financial statements.

# WINDSOR CANADA UTILITIES LTD.

Consolidated Statement of Cash Flows
(In thousands of Canadian dollars)

Year ended December 31, 2018, with comparative information for 2017

| | Notes | 2018 | 2017 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Total comprehensive income for the year | | $ 13,812 | $ 3,698 |
| Adjustments for: | | | |
| Depreciation and amortization | 7, 8 | 14,009 | 13,461 |
| Amortization of deferred revenue customer contribution | | (354) | (317) |
| Remeasurement of employee future benefits | 14 | (7,283) | 5,758 |
| Loss/(gain) on sale of property, plant and equipment | 19 | 361 | (66) |
| Amortization of debt issuance costs | | 13 | 12 |
| Share in joint venture's net loss | | 13 | - |
| Net finance expense | 21 | 1,427 | 1,653 |
| Income tax expense | 16 | 1,467 | 3,867 |
| | | 23,465 | 28,066 |
| Changes in: | | | |
| Accounts receivable | | (1,894) | 9,571 |
| Due from related parties | 22 | 645 | 1,481 |
| Inventory | | 348 | 1,098 |
| Other assets | | 911 | 51 |
| Investment in joint venture | | (100) | - |
| Work in progress | | 33 | 96 |
| Deferred income taxes | | 3,492 | (1,827) |
| Accounts payable and accruals | | (4,435) | (2,063) |
| PIL of income taxes | | 4,705 | (1,656) |
| Due to related parties | 22 | 430 | (566) |
| Deferred revenue | | 6,585 | (1,384) |
| Customer deposits | | (1,807) | 1,172 |
| Employee future benefits | | 3,288 | 3,159 |
| | | 12,201 | 9,132 |
| Interest paid | | (4,375) | (4,330) |
| Interest received | | 2,948 | 2,677 |
| Income taxes paid | | (3,752) | (4,554) |
| **Net cash from operating activities** | | **30,487** | **30,991** |
| Cash flows from investing activities: | | | |
| Acquisition of property, plant and equipment and intangible assets | 7, 8 | (19,592) | (15,582) |
| Acquisition of investments | 9 | (2,200) | (6,200) |
| Gain on investment | 9 | (206) | (209) |
| Deferred revenue - customer contributions | | 2,120 | 2,189 |
| Proceeds on sale of property, plant and equipment | | 360 | 531 |
| **Net cash used in investing activities** | | **(19,518)** | **(19,271)** |
| Cash flows from financing activities: | | | |
| Decrease in due from related parties | 22 | 822 | 822 |
| Dividends paid | | (4,000) | (5,000) |
| **Net cash used in financing activities** | | **(3,178)** | **(4,178)** |
| **Net increase in cash and cash equivalents** | | **7,791** | **7,542** |
| Cash and cash equivalents at January 1 | | 27,949 | 20,407 |
| **Cash and cash equivalents at December 31** | | **$ 35,740** | **$ 27,949** |

The accompanying notes are an integral part of these consolidated financial statements.

# WINDSOR CANADA UTILITIES LTD.

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# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements
(in thousands of Canadian dollars)

Year ended December 31, 2018

**1. Reporting entity:**

Windsor Canada Utilities Ltd. ("WCUL" or the "Corporation") is a holding company owned by its sole shareholder, the Corporation of the City of Windsor. WCUL was incorporated December 1999 under the Business Corporations Act (Ontario). The principal business of WCUL is to provide strategic direction and financing to the operations of ENWIN Utilities Ltd. ("EWU"), a rate-regulated distribution company and ENWIN Energy Ltd. ("EWE"), a non-regulated service company. The address of WCUL's registered office is 787 Ouellette Avenue, Windsor, Ontario, Canada.

The principal activity of WCUL, through its wholly-owned subsidiary, EWU, is the ownership and operation of the electricity distribution grid in the City of Windsor. WCUL, through its wholly-owned subsidiary, EWE, is also responsible for the provision of sentinel lighting to the businesses of the City of Windsor and street lighting maintenance services to the Corporation of the City of Windsor (the "City").

These financial statements are presented on a consolidated basis and include the following subsidiaries: EWU and EWE. Hereafter, for purposes of these notes, unless specifically referenced, any and all references to the "Corporation" refer to WCUL and its subsidiaries EWU and EWE.

On November 6, 2012, EWU and the Windsor Utilities Commission (the "Commission") entered into a Water System Operating Agreement ("WSOA"), whereby EWU agreed to provide services to the Commission with respect to operating the water treatment and distribution system as well as District Energy. The services include: management, administrative services, construction operations, and maintenance services. EWU is responsible for providing all personnel required to operate the water system and District Energy. Pursuant to the terms of the WSOA and the associated Employee Arrangement Agreement, also dated November 6, 2012, the Commission transferred all non-unionized employees and all unionized employees of the Commission to EWU. The Commission is a local board of the City.

Through its wholly-owned subsidiary, EWE, the Corporation has a joint venture investment in ONtech Rapid Coatings Inc. ("ONtech"), which is accounted for using the equity method.

The Corporation's arrangements with its subsidiaries, the Commission and the City are subject to the Ontario Energy Board's ("OEB's") Affiliate Relationships Code, which is a code prescribed by and issued pursuant to the Ontario Energy Board Act, 1998.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

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**2. Basis of preparation:**

(a) Statement of compliance:

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.

(b) Approval of the consolidated financial statements:

The consolidated financial statements were approved by the Board of Directors on April 17, 2019.

(c) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments at fair value through profit or loss, are measured at fair value.

(ii) The accrued benefit related to the Corporation's unfunded defined benefit plan is actuarially determined and is measured at the present value of the defined benefit obligation.

(d) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand dollars.

(e) Use of estimates and judgements:

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

**2. Basis of preparation (continued):**

(e) Use of estimates and judgements (continued):

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

In particular, significant areas where upon estimation was required that have the most significant effect on the amounts recognized in these consolidated financial statements, include:

(i) Note 3(j) – Deferred revenue: determination of the performance obligation for contributions from customers and the related amortization period;
(ii) Note 5 – Trade accounts receivables: allowance for impairment. Unbilled revenue: measurement of revenues not yet billed;
(iii) Note 7 – Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment;
(iv) Note 14 – Employee future benefits: measurement of the defined benefit obligation;
(v) Note 24 – Financial instruments and risk management: valuation of financial instruments.

Information about critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements, include:

(i) The Corporation's determination that they are acting as a principal for electricity distribution and therefore have presented the electricity revenues on a gross basis.

(f) Rate regulation:

Effect of rate-setting regulations on EWU's activities and on these consolidated financial statements:

EWU is regulated by the Ontario Energy Board. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The OEB's regulatory accounting treatments require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS and, as a result, these regulatory assets and liabilities have not been recorded in these consolidated IFRS financial statements.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

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**2. Basis of preparation (continued):**

(f) Rate regulation (continued):

The Ontario Energy Board Act, 1998 conferred on the OEB powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the distribution of electricity and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as EWU, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct business, and filing and process requirements for rate setting purposes.

(i) Rate setting:

The electricity distribution rates and other regulated charges of EWU are determined by the OEB. This regulated rate-setting provides LDCs with the opportunity to recover the revenue requirement associated with owning and operating the LDC. The revenue requirement represents the forecasted prudent costs, including the cost of capital, which will be reasonably necessary for the LDC to invest in the electricity grid, operate the electricity grid, and serve customers in its licenced service area.

(ii) Rate Applications:

As set out in the OEB's Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, dated October 18, 2012, the OEB performs its rate-setting function using a combination of incentive rate-setting and cost of service rate-setting. Both rate-setting techniques are based on applications made by LDCs to the OEB. Provided an LDC meets OEB-specified performance parameters, the LDC can select from one of three rate-setting streams: 4th Generation Incentive Rate-setting, Custom Incentive Rate-setting, or Annual Incentive Rate-setting Index. Each of these streams entails different rate-setting schedules and substantive filing requirements. For all streams, the revenue requirement is established through a cost of service rate-setting application. The selection of stream determines the number of years that cost of service rate-setting application pertains to, and the number of years thereafter that the LDC is expected to file incentive rate-setting applications.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

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**2. Basis of preparation (continued):**

(f) Rate regulation (continued):

(ii) Rate Applications (continued):

Cost of service rate-setting applications recalculate the revenue requirement through a comprehensive review of an LDC's forecasted costs for a prospective test year. The OEB reviews the costs through a rigorous process and ultimately decides on the recovery of allowed forecasted costs through rates. Incentive rate-setting applications mechanistically adjust the revenue requirement using an OEB-prescribed formula. That formula was established on November 21, 2013, in the OEB's Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.

The OEB last used the cost of service technique to set EWU's electricity distribution rates for rates effective May 1, 2009. Since that time, EWU's rates have been mechanistically adjusted by the OEB through incentive rate-setting. EWU is on the Annual Incentive Rate-setting Index stream. EWU may apply for rates using the cost of service technique at a time of its own choosing, provided that EWU continues to meet OEB-specified performance parameters. If EWU does not continue to meet those parameters, the OEB may mandate EWU to file a cost of service rate-setting application.

(iii) Conservation and Demand Management:

New LDC Licence Requirements – Conservation and Demand Management ("CDM") Targets:

On March 26, 2014, the Ontario Energy Board was directed to amend the licenses of electricity distributors to include requirements for achieving certain CDM targets over a six year period commencing January 1, 2015. These targets specify that electricity distributors will make CDM programs (Province-Wide Programs, Local Distributor CDM Programs, or a combination of) available in their licensed service area to all customer segments; that CDM programs will be designated to achieve reductions in

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**2. Basis of preparation (continued):**

(f) Rate regulation (continued):

(iii) Conservation and Demand Management (continued):

electricity consumption; that each distributor shall meet its CDM requirements by making Province-Wide CDM programs; and provide details and results of Local Distributor CDM Programs available to other Distributors upon request, while having regard to any confidentiality and privacy constraints.

On March 31, 2014, the Independent Electricity System Operator ("IESO") was directed to coordinate, support and fund the delivery of CDM programs through electricity distributors to achieve a total of 7 TWh of reductions in electricity consumption over a six year period commencing January 1, 2015. EWU's contribution to the provincial target of 7 TWh is 151.3 GWh.

**3. Significant accounting policies:**

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements.

(a) Cash and cash equivalents:

Cash and cash equivalents consist of balances with banks and investments with a maturity of approximately three months or less at the date of purchase, unless they are held for investment rather than liquidity purposes, in which case they are classified as an investment.

(b) Financial instruments:

The Corporation adopted IFRS 9 Financial Instruments on January 1, 2018. There were no material adjustments required to the Corporation's financial results; however the Corporation has reclassified its financial instruments.

All consolidated financial assets and liabilities of the Corporation are classified into one of the following categories: amortized cost, fair value through other comprehensive income, or fair value through profit or loss.

# WINDSOR CANADA UTILITIES LTD.



## 3. Significant accounting policies (continued):

(b) Financial instruments (continued):

The Corporation has classified its financial instruments as follows:

| | |
|---|---|
| Cash and cash equivalents | Amortized cost |
| Accounts receivable | Amortized cost |
| Due from related parties | Amortized cost |
| Investment | Fair value through profit or loss |
| Accounts payable and accruals | Amortized cost |
| Due to related parties | Amortized cost |
| Long-term borrowings | Amortized cost |

Financial instruments are recognized initially at amortized cost plus any directly attributable transaction costs.

Subsequent to initial recognition, financial instruments classified as fair value through profit and loss are measured at fair value. The Corporation does not use derivative instruments.

The Corporation derecognizes a financial asset when the contractual rights to the cash flows from the asset expire or it transfers the rights to receive the contractual cash flows in a transaction in which substantially all of the risks and rewards of ownership of the financial asset are transferred.

The Corporation derecognizes a financial liability when its contractual obligations are discharged, cancelled or expire.

(c) Fair value:

Fair values are categorized into different levels in a fair value hierarchy based on inputs used in the valuation techniques as follows:

Level 1: unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset, either directly or indirectly; and

Level 3: inputs for assets and liabilities that are based on observable market data.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**3. Significant accounting policies (continued):**

(d) Inventory:

Inventory is measured at the lower of cost and net realizable value. The cost of inventory is determined on a weighted average basis. Net realizable value is determined on a replacement cost basis.

(e) Property, plant and equipment:

(i) Recognition and measurement:

Items of property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour, any other costs directly attributable to bringing the asset to a working condition for its intended use, the costs of dismantling and removing the items and restoring the site on which they are located and capitalized borrowing costs. Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation's average cost of borrowing.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

(ii) Subsequent costs:

The cost of replacing part of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. The carrying amount of the replaced part is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in income as incurred.

**3. Significant accounting policies (continued):**

(e) Property, plant and equipment (continued):

(iii) Depreciation:

Depreciation is recognized in income on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. The estimated useful lives for the current and comparative years are as follows:

| | |
|---|---|
| Buildings | 10 – 50 years |
| Distribution and metering equipment | 8 – 80 years |
| Other assets | 5 – 20 years |

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized within other income in the consolidated statement of income.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(f) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased, which have finite useful lives, are measured at cost less accumulated amortization and accumulated impairment losses.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**3. Significant accounting policies (continued):**

(f) Intangible assets (continued):

(ii) Amortization:

Amortization is recognized in the consolidated statement of income on a straight-line basis over the estimated useful lives of the intangible assets, from the date that they are available for use. The estimated useful lives for the current and comparative years are:

| | |
|---|---|
| Computer software | 5 – 10 years |

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date.

(g) Work in progress:

Work in progress is recorded at cost, with cost being determined based on material purchased services, internal labour and overhead, as applicable.

(h) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

All impairment losses are recognized in the consolidated statement of income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in the consolidated statement of income.

**3. Significant accounting policies (continued):**

(h) Impairment (continued):

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than inventory, work-in-progress and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in the consolidated statement of income and are allocated to reduce the carrying amount of the assets in the cash-generating unit on a pro-rata basis.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**3. Significant accounting policies (continued):**

(i) Employee future benefits:

(i) Pension plan:

EWU provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension assets and liabilities information by individual employer, there is not sufficient information to enable EWU to account for the plan as a defined benefit plan. The plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in income when they are due. At December 31, 2018, the OMERS plan is in a deficit position.

(ii) Post-employment benefits, other than pension:

EWU pays certain health, dental and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees. These benefits are provided through a group defined benefit plan. EWU is the legal sponsor of the Plan. There is a policy in place to allocate the net defined benefit cost to the entities participating in the group plan. The allocation is based on the obligation attributable to the plan participants. EWU has reflected its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these consolidated financial statements.

EWU accrues the cost of these employee future benefits over the periods in which the employees earn the benefits. The accrued benefit obligations and the current service costs are actuarially determined by applying the projected unit credit method and reflect management’s best estimate of certain underlying assumptions. The current service cost for a period is equal to the actuarial present value of benefits attributed to that period in which employees rendered their services.

**3. Significant accounting policies (continued):**

(i) Employee future benefits (continued):

(ii) Post-employment benefits, other than pension (continued):

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses are recognized immediately in other comprehensive income. EWU determines the net interest expense on the net defined benefit liability for the period by applying the discount rate used to measure the defined benefit liability at the beginning of the annual period, taking into account any changes in the net benefit liability during the period as a result of benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized in the consolidated statement of income.

Gains and losses on account of curtailment of settlement of these employee future benefits are recognized immediately in income.

In accordance with the WSOA and the Employee Arrangement Agreement between the Commission and EWU, the Plan was amended such that all active Commission management and union employees were included as part of the Plan, and have their coverage sponsored by EWU. A date of December 31, 2012 was assumed by the actuary to reflect this event in the Plan.

(j) Deferred revenue:

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. These contributions are received to obtain a connection to the distribution system in order to receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

**3. Significant accounting policies (continued):**

(k) Customer deposits:

Customer deposits include cash collections from customers, which are applied against any unpaid portion of individual customer accounts. Effective January 1, 2011, the OEB required that a customer's deposit be applied to the customer's account prior to the severance process commencing. OEB rules also specify that customer deposits in excess of unpaid account balances must be refunded to customers. Customer deposits are also refundable at EWU's discretion when a customer demonstrates an acceptable level of credit risk. EWU only retains commercial deposits. Customer deposits also include monies received from developers and distribution customers for services that are recorded as construction in progress and, once the assets are put into service, will be accounted for through a capital contribution.

(l) Revenue recognition:

IFRS 15 *Revenue from contracts with customers* became effective January 1, 2018. This standard established a comprehensive framework for determining whether, how much and when revenue is recognized. Based on the new revenue recognition criteria there was no material adjustment to the Corporation's revenue.

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that EWU has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Revenue for EWU is recognized when EWU satisfies the performance obligations within the contract(s) for conditions of service, which is when the distribution and delivery of electricity is achieved or specific services are performed.

# WINDSOR CANADA UTILITIES LTD.



**3. Significant accounting policies (continued):**

(l) Revenue recognition (continued):

Revenue includes an estimate of unbilled revenue. Unbilled revenue represents an estimate of electricity consumed by customers since the date of each customer's last meter reading. Actual electricity usage could differ from those estimates.

Revenue is measured at the fair value of the consideration received or receivable, net of any taxes which may be applicable.

Street lighting maintenance revenue – EWE has a contract with the City to provide maintenance of the street lighting system. This contract includes replacing damaged or non-functioning street lighting. Revenue is recognized when the services have been performed. There is also a fixed component to the contract that is recognized evenly throughout the year.

Sentinel lighting revenue – EWE provides sentinel lighting equipment to customers. A monthly rental charge is earned by EWE for the use of the sentinel light equipment.

Other income for work orders is recorded on a net basis as the Corporation is acting as an agent for this revenue stream. All other amounts in other income are recorded on a gross basis and are recognized when services are rendered.

(m) Finance costs:

Finance costs comprise interest expense on borrowings and unwinding of the discount rate on provisions.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**3. Significant accounting policies (continued):**

(n) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in the consolidated statement of income except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

Under the Electricity Act 1998, the Corporation makes payments in lieu of corporate taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998 and related regulations. Payments in lieu of taxes ("PILS") are referred to as income taxes.

Current tax is the expected PILs payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the consolidated statement of income in the year that includes the date of enactment or substantive enactment.

(o) Set-off and reporting on a net basis:

Assets and liabilities and income and expenses are not offset and reported on a net basis unless required or permitted by IFRS. For financial assets and financial liabilities, offsetting is permitted when, and only when, the Corporation has a legally enforceable right to set-off and intends either to settle on a net basis, or to realize the asset and settle the liability simultaneously.

# WINDSOR CANADA UTILITIES LTD.



**3. Significant accounting policies (continued):**

(p) New standards and interpretations not yet adopted:

The following standards, which are not yet effective for the year ended December 31, 2018, have not been applied in preparing these consolidated financial statements.

IFRS 16 Leases

IFRS 16, issued on January 13, 2016, introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by lessors. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided.

IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. IFRS 16 will replace IAS 17. The Corporation has assessed the potential impacts on its consolidated financial statements, and determined that IFRS 16 will not impact the Corporation in 2019.

IFRIC 23 Uncertainty over Income Tax Treatments

IFRIC 23 intends to clarify how to apply the recognition and measurement requirements in IAS 12 *Income Taxes.* The IFRIC is effective for annual periods beginning on or after January 1, 2019.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 4. Cash and cash equivalents:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Cash and cash equivalents | $ | 35,740 | $ | 27,949 |
| Cash and cash equivalents | $ | 35,740 | $ | 27,949 |

The Corporation has an agreement with a Canadian chartered bank for an operating line of credit in the amount of $75,000 (2017 - $75,000) bearing interest at prime minus 0.25%. The line of credit restricts the availability of the Corporation to lien assets. As of December 31, 2018, the outstanding balance in the line of credit was $nil (2017 - $nil).

## 5. Accounts receivable:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Trade receivables | $ | 23,763 | $ | 21,169 |
| Unbilled revenue | | 25,888 | | 26,641 |
| Allowance for doubtful accounts | | (985) | | (1,038) |
| Accounts receivable | $ | 48,666 | $ | 46,772 |

## 6. Inventory:

Inventory consists of parts and supplies acquired for capital, internal construction, maintenance or recoverable work.

The amount of inventory consumed by the Corporation and recognized as an expense during 2018 was $5,625 (2017 - $5,164).

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 7. Property, plant and equipment:

(a) Cost:

| | Land and buildings | Distribution and metering equipment | Other assets | Construction work-in-progress | Total |
|---|---|---|---|---|---|
| Balance at January 1, 2017 | $ 20,739 | $ 222,623 | $ 18,417 | $ 3,380 | $ 265,159 |
| Additions | 364 | 13,019 | 1,405 | (368) | 14,420 |
| Disposals/retirements | (22) | (600) | - | - | (622) |
| Balance at December 31, 2017 | $ 21,081 | $ 235,042 | $ 19,822 | $ 3,012 | $ 278,957 |
| Balance at January 1, 2018 | $ 21,081 | $ 235,042 | $ 19,822 | $ 3,012 | $278,957 |
| Additions | 229 | 15,523 | 4,473 | (1,121) | 19,104 |
| Disposals/retirements | (13) | (823) | - | - | (836) |
| Balance at December 31, 2018 | $ 21,297 | $ 249,742 | $ 24,295 | $ 1,891 | $ 297,225 |

(b) Accumulated depreciation:

| | Land and buildings | Distribution and metering equipment | Other assets | Construction work-in-progress | Total |
|---|---|---|---|---|---|
| Balance at January 1, 2017 | $ 5,211 | $ 33,292 | $10,436 | $ - | $ 48,939 |
| Depreciation charge for the year | 918 | 6,659 | 1,664 | - | 9,241 |
| Disposals/retirements | - | (157) | - | - | (157) |
| Balance at December 31, 2017 | $ 6,129 | $ 39,794 | $12,100 | $ - | $ 58,023 |
| Balance at January 1, 2018 | $ 6,129 | $ 39,794 | $12,100 | $ - | $ 58,023 |
| Depreciation charge for the year | 931 | 6,896 | 1,918 | - | 9,745 |
| Disposals/retirements/transfers | (2) | (207) | 94 | - | (115) |
| Balance at December 31, 2018 | $ 7,058 | $ 46,483 | $14,112 | $ - | $ 67,653 |

(c) Carrying amounts:

| | Land and buildings | Distribution and metering equipment | Other assets | Construction work-in-progress | Total |
|---|---|---|---|---|---|
| December 31, 2017 | $ 14,952 | $ 195,248 | $ 7,722 | $ 3,012 | $ 220,934 |
| December 31, 2018 | $ 14,239 | $ 203,259 | $ 10,183 | $ 1,891 | $ 229,572 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 8. Intangible assets:

(a) Cost or deemed cost:

| | | Computer software |
|---|---|---|
| Balance at January 1, 2017 | $ | 28,327 |
| Additions | | 1,162 |
| Balance at December 31, 2017 | $ | 29,489 |
| Balance at January 1, 2018 | $ | 29,489 |
| Additions | | 488 |
| Balance at December 31, 2018 | $ | 29,977 |

(b) Accumulated amortization:

| | | Computer software |
|---|---|---|
| Balance at January 1, 2017 | $ | 16,571 |
| Amortization charge for the year | | 4,220 |
| Balance at December 31, 2017 | $ | 20,791 |
| Balance at January 1, 2018 | $ | 20,791 |
| Amortization charge for the year | | 4,264 |
| Balance at December 31, 2018 | $ | 25,055 |

(c) Carrying amounts:

| | | Computer software |
|---|---|---|
| December 31, 2017 | $ | 8,698 |
| December 31, 2018 | $ | 4,922 |

(in thousands of Canadian dollars)

## 9. Investment:

In 2018, EWE invested in short term fixed income investments. An initial investment of $3,054 has been invested in a one year term deposit at a rate of 3.5% compounded annually (2017 – $1,000) with a maturity date of October 26, 2019. Another investment of $3,000 (2017 – $2,500) has been invested in a high interest savings account at the rate of prime plus 1.45%.

| | 2018 | 2017 |
|---|---|---|
| Investment: | | |
| Cashable GIC | $ - | $ 1,003 |
| Term deposit | 3,071 | 1,506 |
| High interest savings | 3,058 | 2,503 |
| Total investment | $ 6,129 | $ 5,012 |

In 2014, a sinking fund was established with the intent to ensure sufficient funds are available to settle debentures issued November 6, 2012, with a maturity date of November 6, 2042, in the amount of $103,000. There are no restrictions with this investment. Annual payments are expected to be completed to satisfy the obligation.

These investments are recorded at fair value as of December 31, 2018, and are invested in fixed income and equity markets as established by the Corporation's investment policy.

| | 2018 | 2017 |
|---|---|---|
| Investment: | | |
| Sinking fund | $ 7,819 | $ 6,530 |
| Investment, sinking fund | $ 7,819 | $ 6,530 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 10. Accounts payable and accruals:

| | 2018 | 2017 |
|---|---|---|
| Trade payables | $ 22,020 | $ 22,632 |
| Accrued expenses | 3,989 | 7,812 |
| | $ 26,009 | $ 30,444 |

See accounting policies in Note 3(b). Information about the Corporation’s exposure to currency and liquidity risk is included in Note 24.

## 11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Customer deposits comprise:

| | 2018 | 2017 |
|---|---|---|
| Customer deposits | $ 5,114 | $ 6,770 |
| Construction deposits | 1,724 | 1,875 |
| | 6,838 | 8,645 |
| Less: current portion | 919 | 1,211 |
| | $ 5,919 | $ 7,434 |

## 12. Deferred revenue – customer contributions:

Deferred revenue relates to the capital contributions received from customers and others. The amount of deferred revenue received from customers is $14,447 (2017 - $12,681). Deferred revenue is recognized as revenue on a straight-line basis over the life of the asset for which the contribution was received.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 13. Long-term borrowings:

Long-term borrowings comprise:

| | 2018 | 2017 |
|---|---|---|
| Debentures payable | $ 103,000 | $ 103,000 |
| Less: debt issuance costs | (530) | (543) |
| | $ 102,470 | $ 102,457 |

Senior unsecured debentures, which have a maturity date of November 6, 2042, and bearing interest at a rate of 4.134% per annum, were issued on November 6, 2012. Interest is payable in equal semi-annual instalments, in arrears, on May 6 and November 6 each year commencing May 6, 2013, until maturity. The debentures are represented by a single Global Debenture Certificate registered in the name of CDS & Co. In order to put the debentures in place, the Corporation incurred debt issuance costs in the amount of $601. The debentures require semi-annual interest payments only to 2042 of $2,129, with a final principal payment of $103,000 due November 6, 2042.

The Corporation incurred interest expense in respect of the debentures of $4,258 (2017 - $4,258), which is recognized as part of finance expense on the consolidated statement of income.

The Commission is a guarantor of $52,000 in relation to the debentures and is a borrower of that same amount from WCUL pursuant to a revolving credit agreement also entered into on November 6, 2012. The Commission is obligated to make due and punctual payments of the principal and applicable interest on each debenture on their due dates, on maturity, on redemption or on acceleration.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 14. Employee future benefits:

EWU pays certain health, dental and life insurance benefits on behalf of its retired employees. Significant assumptions underlying the actuarial valuation include management's best estimate of the interest (discount) rate, mortality decrement, the average retirement age of employees, employee turnover and expected health and dental care costs.

The Plan was amended such that all active Commission management and union employees covered under the Commission collective agreement from July 1, 2012, would be included as part of the Plan and have their coverage sponsored by EWU. The December 31, 2012 date was chosen to reflect this event in the Plan. Reference note 1 for further information.

EWU measures its accrued benefit liability for accounting purposes as at December 31 each year. A valuation date of December 31, 2016, with extrapolation to December 31, 2018, has been used to calculate the current obligation. EWU's employee future benefit liability consists of the following:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Defined benefit liability | $ | 64,397 | $ | 68,392 |
| Defined benefit liability, end of year | $ | 64,397 | $ | 68,392 |

Information about EWU's unfunded defined benefit plan is as follows:

Changes in the present value of the defined benefit liability:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Defined benefit liability, beginning of year | $ | 68,392 | $ | 59,475 |
| Defined benefit expense | | 4,825 | | 4,647 |
| Actuarial (gain)/loss on liability recognized in other comprehensive income | | (7,283) | | 5,758 |
| Benefits paid for the year | | (1,537) | | (1,488) |
| Defined benefit liability, end of year | $ | 64,397 | $ | 68,392 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 14. Employee future benefits (continued):

Components of net benefit expense recognized are as follows:

| | 2018 | 2017 |
|---|---|---|
| Current service cost | $ 2,528 | $ 2,358 |
| Interest cost | 2,297 | 2,289 |
| Net benefit expense | $ 4,825 | $ 4,647 |

Net benefit expense for the year is recognized as administrative expense on the consolidated statement of income.

The main actuarial assumptions underlying the valuation are as follows:

(a) Health care cost trend rates:

The health care cost trend for prescription drugs is estimated to increase at 6.5% in 2018 grading down to 4.5% by 2027. Other health expenses are estimated to increase at 5.83% grading down to 4.5% by 2027. Dental expenses are estimated to increase at 4.0% per year.

(b) Financial instruments:

The liabilities at the period end and the present value of future liabilities were determined using a discount rate of 4.0% (2017 - 3.4%) representing an estimate of the yield on high quality corporate bonds as at the valuation date.

(in thousands of Canadian dollars)

# WINDSOR CANADA UTILITIES LTD.



## 14. Employee future benefits (continued):

(c) Mortality decrement:

The rates applicable to public sector retirees in the 2014 Canadian Pensioners Mortality table ("CPM 2014") produced by the Canadian Institute of Actuaries ("CIA") were used as the basis of these assumptions.

A 1% or one year change in actuarial assumptions, assuming all other factors remain constant, has the following impact on the defined benefit liability carrying amount:

| | December 31, 2018 | | December 31, 2017 | |
|---|---|---|---|---|
| | Increase | Decrease | Increase | Decrease |
| Health care trend rate (1% change) | $ 12,236 | $ (9,605) | $ 12,993 | $ (10,199) |
| Discount rate (1% change) | $ (10,312) | $ 13,390 | $ (10,950) | $ 14,219 |
| Mortality (1 year) | $ 2,817 | $ (2,721) | $ 2,992 | $ (2,890) |

## 15. Pension plan:

EWU participates in the Ontario Municipal Employees Retirement Fund ("OMERS"), a multi-employer plan, on behalf of its employees. The plan has been accounted for as a defined contribution plan. Contributions during the year were 9.0% (2017 - 9.0%) for employee earnings below the year's maximum pensionable earnings and 14.6% (2017 - 14.6%) thereafter. During 2018, EWU expensed contributions totalling $2,937 (2017 - $2,887) made to OMERS in respect of the employer's required contributions to the plan. Estimated contributions for 2019 are $3,030.

## 16. Income taxes (provision for payment in lieu of corporate taxes):

| | 2018 | 2017 |
|---|---|---|
| Current tax expense: | | |
| Current year | $ 4,305 | $ 3,925 |
| Adjustments for prior years | (2,838) | (58) |
| Deferred tax expense: | | |
| Origination and reversal of temporary differences | 3,498 | (2,343) |
| Adjustments for prior years | - | 478 |
| Tax related to remeasurement of employee future benefits | (1,930) | 1,526 |
| Total income taxes expense | $ 3,035 | $ 3,528 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 16. Income taxes (provision for payment in lieu of corporate taxes) (continued):

The provision for income taxes varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

| | 2018 | 2017 |
|---|---|---|
| Basic rate applied to total comprehensive income before income tax | 26.50% | 26.50% |
| Change in income tax resulting from: | | |
| Items not deductible for tax purposes and other | (0.09%) | 4.29% |
| Effective rate applied to comprehensive income before income taxes | 26.41% | 30.79% |

The components of the deferred income tax assets and liabilities are summarized as follows:

| | 2018 | 2017 |
|---|---|---|
| Deferred tax assets: | | |
| Employee benefits | $ 10,747 | $ 11,589 |
| Property, plant and equipment | 9 | 4 |
| Regulatory assets | 428 | - |
| Other | 250 | 309 |
| Deferred tax liabilities: | | |
| Property, plant and equipment | 4,824 | 1,034 |
| Regulatory liabilities | - | 748 |
| Other | 100 | 118 |
| Net deferred income tax asset | $ 6,510 | $ 10,002 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 16. Income taxes (provision for payment in lieu of corporate taxes) (continued):

At December 31, 2018, a deferred tax asset of $6,510 (2017 - $10,002) has been recorded. The utilization of this tax asset is dependent on future taxable income in excess of income arising from the reversal of existing taxable temporary differences. The Corporation believes that this asset should be recognized as it will be recovered through future rates.

## 17. Share capital:

| | 2018 | 2017 |
|---|---|---|
| Authorized: | | |
| Unlimited common shares | | |
| Issued: | | |
| 2,000 common shares | $ 81,842 | $ 81,842 |

## 18. Distribution revenue:

EWU generates revenue primarily from the sale and distribution of electricity to its customers. Other revenue consists of services provided to related parties and other income. Additional information is provided in Note 19 with the components of other income.

In the following table, distribution revenue is disaggregated by type of customer:

| | 2018 | 2017 |
|---|---|---|
| Residential | $ 25,910 | $ 24,490 |
| General service – small distribution | 19,525 | 19,025 |
| General Service – large distribution | 4,638 | 4,565 |
| Street lighting distribution | 1,793 | 1,715 |
| Total distribution revenue | $ 51,866 | $ 49,795 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 19. Other Income:

Other income comprises:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Change in occupancy | $ | 372 | $ | 403 |
| Late payment and collection charges | | 378 | | 366 |
| Other operating revenues | | 2,726 | | 3,280 |
| (Loss)/gain on disposal of property, plant and equipment | | (361) | | 66 |
| Pole rental | | 775 | | 618 |
| Sale of scrap | | 116 | | 82 |
| Sewer surcharge billing and collecting | | 2,876 | | 2,891 |
| Sentinel lighting rental | | 99 | | 100 |
| Total other income | $ | 6,981 | $ | 7,806 |

## 20. Employee benefits:

| | Note | | 2018 | | 2017 |
|---|---|---|---|---|---|
| Salaries and benefits | | $ | 24,987 | $ | 24,066 |
| Contributions to multi-employer plan | 15 | | 2,937 | | 2,887 |
| Expenses related to defined benefit plans | 14 | | 4,825 | | 4,647 |
| | | $ | 32,749 | $ | 31,600 |

## 21. Finance expense (income):

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Finance income: | | | | |
| Interest income on loans to affiliate | $ | (2,150) | $ | (2,150) |
| Interest income on bank balances | | (556) | | (259) |
| Income on investment | | (236) | | (268) |
| Interest income on PILs refund | | (6) | | - |
| | $ | (2,948) | $ | (2,677) |
| Finance expense: | | | | |
| Interest expense on long-term borrowings | $ | 4,258 | $ | 4,258 |
| Discount on related party debt | | 13 | | 12 |
| Other | | 104 | | 60 |
| | $ | 4,375 | $ | 4,330 |
| Net finance expense | $ | 1,427 | $ | 1,653 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 22. Related party transactions:

(a) Parent and ultimate controlling party:

The parent is the Corporation of the City of Windsor (the "City"). The City produces consolidated financial statements that are available for public use.

(b) Key management personnel:

The key management personnel of the Corporation has been defined as members of its board of directors and executive management team members.

Key management compensation:

| | 2018 | 2017 |
|---|---|---|
| Salaries and other short-term benefits | $ 1,158 | $ 1,116 |
| Post-employment benefits | 14 | 12 |
| | $ 1,172 | $ 1,128 |

(c) Transactions with parent:

EWU provides waste water billing and related services for the City, for which EWU charges a fee. The total amount charged to the City for the year ended December 31, 2018, was $2,876 (2017 - $2,891). The fee charged for the waste water billing and related services were recognized as other income from operations on the consolidated statement of income.

EWU collects and remits the waste water billing amounts on behalf of the City. The total amount owing to the City at December 31, 2018, relating to waste water billing was $5,649 (2017 - $5,219).

EWE provides street lighting maintenance services to the City. The total amount charged to the City for the year ended December 31, 2018, relating to street lighting maintenance services was $1,503 (2017 - $1,817) and is recorded as part of other income from operations in the consolidated statement of income.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**22. Related party transactions (continued):**

(d) Transactions with entities under common control:

On November 6, 2012, EWU and the Commission entered into a WSOA, whereby EWU agreed to provide services to the Commission with respect to the operation of the Commission's water system and District Energy. The total amount charged to the Commission for the year ended December 31, 2018, was $20,004 (2017 - $19,336).

(e) Amounts due from (to) related parties:

The amounts due from related parties consist of:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Due from company under common control: | | | | |
| Due from Windsor Utilities Commission | $ | 2,338 | $ | 3,145 |
| Due from parent: | | | | |
| Due from the Corporation of the City of Windsor | | 445 | | 283 |
| | $ | 2,783 | $ | 3,428 |

The amounts due from the City and the Commission are due on demand and are non-interest bearing. These amounts have no specified repayment terms.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 22. Related party transactions (continued):

(e) Amounts due from (to) related parties (continued):

Long term receivable due from related parties consist of:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Due from Windsor Utilities Commission, debentures | $ | 52,000 | $ | 52,000 |
| Due from Windsor Utilities Commission, post-retirement | | 2,877 | | 3,699 |
| Less: Current portion post–retirement | | 822 | | 822 |
| Due from Windsor Utilities Commission | $ | 54,055 | $ | 54,877 |

The amount due from the Commission, debentures is pursuant to the revolving credit agreement entered into by the Commission and the Corporation.

The amount due from the Commission, post-retirement, is a long term receivable resulting from the Employee Arrangement Agreement with EWU and is amortized over the estimated average remaining service life at the time of the agreement which was 9.5 years, payable each November.

The amounts due to related parties consist of:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Due to parent: | | | | |
| Due to the Corporation of the City of Windsor | $ | 5,649 | $ | 5,219 |
| | $ | 5,649 | $ | 5,219 |

The amount due to the City is non-interest bearing.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 23. Joint venture:

ONtech Rapid Coatings Inc. ("ONtech") is a Canadian controlled private corporation in which EWE has joint control and a 50% ownership interest. ONtech was founded by EWE and Tessonics Inc. and is principally engaged to offer low pressure cold spray solutions. The address of ONtech's registered office is 787 Ouellette Avenue, Windsor, Ontario, Canada.

ONtech is structured as a separate legal entity and EWE has a residual interest in its net assets. Accordingly, the Corporation has classified its interest in ONtech as a joint venture, which is accounted for using the equity method.

## 24. Financial instruments and risk management:

The carrying values of cash and cash equivalents, accounts receivable, amounts due from (to) related parties, investment, accounts payable and accruals approximate fair values because of the short maturity of these instruments.

The following table illustrates the classification of the corporation's financial instruments using the fair value hierarchy as at December 31:

| | December 31, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| Assets | Level 1 | Level 2 | Total | Level 1 | Level 2 | Total |
| Investment - fixed income | $ - | $ 12,641 | $ 12,641 | $ - | $ 10,035 | $ 10,035 |
| Investment – equity | 1,307 | - | 1,307 | 1,507 | - | 1,507 |
| | $ 1,307 | $ 12,641 | $ 13,948 | $ 1,507 | $ 10,035 | $ 11,542 |

The fair value of the investments is $13,948 (2017 - $11,542). The fair value is calculated based on the quoted market price in the active markets.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 24. Financial instruments and risk management (continued):

(i) Credit risk:

The aging of accounts receivables at the reporting date was:

| | 2018 | 2017 |
|---|---|---|
| Not past due | $ 43,585 | $ 42,432 |
| Past due 0 – 30 days | 2,383 | 2,182 |
| Past due 31 – 60 days | 893 | 593 |
| Greater than 60 days | 1,805 | 1,565 |
| | $ 48,666 | $ 46,772 |

Financial assets carry credit risk that a counter-party will fail to discharge an obligation which would result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Windsor. No single customer accounts for greater than 8.1% (2017 - 9%) of revenues.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in the consolidated statement of income. Subsequent recoveries of receivables previously provisioned are credited to the consolidated statement of income. The balance of the allowance for impairment at December 31, 2018 was $985 (2017 - $1,038).

A continuity of the allowance for doubtful accounts is as follows:

| | 2018 | 2017 |
|---|---|---|
| Balance, beginning of year | $ 1,038 | $ 1,251 |
| Accounts receivable balances written off | (385) | (590) |
| Change in provisions for doubtful accounts | 332 | 377 |
| Balance, end of year | $ 985 | $ 1,038 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

**24. Financial instruments and risk management (continued):**

(i) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2018, approximately $1,805 (2017 - $1,565) is considered 60 days past due. Credit risk is managed through collection of security deposits from customers in accordance with OEB regulation. As of December 31, 2018, the Corporation holds security deposits in the amount of $5,114 (2017 - $6,770).

(ii) Liquidity risk:

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to a line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The following are the contractual maturities of financial liabilities:

| 2018 | 6 Months or less | 6-12 Months | 1-2 years | More than 2 years | Other non cash adjustments | Carrying amount |
|---|---|---|---|---|---|---|
| Accounts payable and accruals | $ 25,897 | $ 112 | $ - | $ - | $ - | $ 26,009 |
| Due to related parties | 5,649 | - | - | - | - | 5,649 |
| Customer deposits | 460 | 459 | 919 | 5,000 | - | 6,838 |
| Long-term borrowings | - | - | - | 103,000 | (530) | 102,470 |
| | $ 32,006 | $ 571 | $ 919 | $108,000 | $ (530) | $140,966 |

| 2017 | 6 Months or less | 6-12 Months | 1-2 years | More than 2 years | Other non cash adjustments | Carrying amount |
|---|---|---|---|---|---|---|
| Accounts payable and accruals | $ 30,301 | $ 143 | $ - | $ - | $ - | $ 30,444 |
| Due to related parties | 5,219 | - | - | - | - | 5,219 |
| Customer deposits | 601 | 601 | 1,211 | 6,232 | - | 8,645 |
| Long-term borrowings | - | - | - | 103,000 | (543) | 102,457 |
| | $ 36,121 | $ 744 | $ 1,211 | $109,232 | $ (543) | $144,765 |

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

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**24. Financial instruments and risk management (continued):**

(iii) Market risk:

Market risks primarily refer to the risk of loss that results from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates because the OEB-prescribed regulated rate of return for the Corporation's distribution business, which allows for the recovery of the prudent cost of capital, is derived in part based on the forecast for long-term Government of Canada bonds yields. For sensitivity purposes, a 1% change in equities would result in a change of $13 (2017 - $15) on the consolidated balance sheet and consolidated statement of income.

(iv) Capital disclosures:

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2018, shareholder's equity amounts to $171,682 (2017 - $161,870) and long-term debt amounts to $102,470 (2017 - $102,457).

Through rate-setting, the OEB determines the prudent costs of capital that are recoverable by EWU in relation to the distribution business. These costs of capital are the interest on debt and return on equity The OEB permits recovery on the basis of a deemed capital structure of 60% debt and 40% equity. The actual capital structure for the Corporation may differ from the OEB deemed structure.

The Corporation has customary covenants typically associated with long-term debt. The Corporation is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

## 24. Financial instruments and risk management (continued):

(v) Interest rate risk:

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Corporation is subject to variable interest rate cash flow risk with respect to its investments. The Corporation has addressed this risk by entering into fixed interest rates on invested funds and debts.

(vi) Currency risk:

Currency risk is the risk that the fair value or future cash flow of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation is exposed to currency risk through its foreign currency denominated bank and investment accounts. A weakening or strengthening of the Canadian dollar can affect the cash flows. This risk is monitored by investment managers and the exposure is limited to these accounts. For sensitivity purposes, a 1% change in the Canadian dollar would result in a change of $nil (2017 - $9) on the consolidated balance sheet and consolidated statement of income.

## 25. Commitments and contingencies:

**Contingencies**

*General*

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

*General liability insurance*

The Corporation is a member of the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"), a self-insurance plan that pools the liability risks of all the Municipal Electric Utilities in Ontario. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE for the years in which the Corporation was a member.

To December 31, 2018, the Corporation has not been made aware of any additional assessments that have not been accrued.

# WINDSOR CANADA UTILITIES LTD.

Notes to the Consolidated Financial Statements (continued)
(in thousands of Canadian dollars)

Year ended December 31, 2018

## 26. Regulatory assets and liabilities:

Under IFRS, there is no recognition of regulatory assets or liabilities, and therefore, the impacts of these transactions are reflected on the consolidated statement of income, as applicable. As a result of not recognizing rate-regulated assets and liabilities, the effect was to increase (decrease) comprehensive income as follows:

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Gross income: | | | | |
| Retail settlement variance | $ | (19) | $ | 1,144 |
| Expenses: | | | | |
| Retail cost variance | | 164 | | (142) |
| Property, plant and equipment (Mist Meters) | | (203) | | 96 |
| PILS | | (1,170) | | 339 |
| Future PILS | | (1,568) | | 339 |
| Regulatory adjustment for IFRS conversion | | 2,374 | | 2,280 |
| Disposition and recovery of regulatory balances | | (4,413) | | (3,445) |
| Interest expense (net of interest revenue) | | (52) | | 61 |
| Other | | 89 | | - |
| Change in comprehensive income (loss) | $ | (4,798) | $ | 333 |

## 27. Comparative figures:

Certain reclassifications have been made to the prior year's consolidated financial statements to enhance comparability with the current year's consolidated financial statements. As a result, certain line items have been amended in the consolidated balance sheet, consolidated statement of income and other comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flow and the related notes to the consolidated financial statements. There was no impact on current or prior year's net income. Comparative figures have been adjusted to conform to the current year's presentation.


**We partnered with the Windsor-Detroit Bridge Authority to build electrical infrastructure for the Gordie Howe International Bridge.**

**Windsor Canada Utilities Ltd.**
**ENWIN Utilities Ltd.**
**ENWIN Energy Ltd.**
787 Ouellette Avenue
P.O. Box 1625, Station A
Windsor, Ontario
N9A 5T7

ENWIN

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Reference:

Appendix 2-Z Cost of Power

Preamble:

EnWin Utilities calculates the cost of power expense in Appendix 2-Z using the 2017 actual loads for RPP and Non-RPP Class A and Class B customers and using the RPP and Non-RPP prices from "Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019" and the "Regulated Price Plan Cost Supply Report May 1, 2018 – April 30, 2019".

OEB staff notes that on April 17, 2019, the OEB issued the updated RPP prices and supply cost reports effective May 1, 2019. EnWin Utilities states that it used 2020 load forecast adjusted for the CDM activities to calculate the cost of power. However, OEB staff notes that the 2019 and 2020 loads used in the Appendix 2-Z do not match with the loads in the load forecast model.

Question:

a) Please update the Appendix 2-Z using the most updated RPP prices, GA modifier and the 2018 actual loads.

b) Please explain the discrepancies noted between the 2019 and 2020 loads used in the Appendix 2-Z and the loads in the load forecast model.

Response:

a) Please see Attachment 1.

   ENWIN has also adjusted the forecasted load in Appendix 2-Z to encompass ENWIN's updated 2020 load forecast, and to exclude estimated wholesale market participants' volumes.

b) The noted discrepancies are due to loss adjustments and the Large-Use FA rate class. The Appendix 2-Z loads are loss-adjusted, while those in the load forecast model are not. The Large Use-FA rate class forecasted load was excluded from the original Appendix 2-Z calculation, as the customer currently in this rate class is a wholesale market participant. As noted above, ENWIN has now updated Appendix 2-Z in Attachment 1 to also exclude all other wholesale market participants' forecasted load embedded within other rate classes.

Please see below for the reconciliation between the original filed load forecast and the original filed Appendix 2-Z.

| Class A | 2019 | | | 2020 | | |
|---|---|---|---|---|---|---|
| Customer | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) |
| General Service 50 to 4999 kW | 245,521,171 | 1.0377 | 254,777,319 | 237,610,452 | 1.0311 | 244,990,181 |
| General Service 3000-4999 kW | 27,373,838 | 1.0377 | 28,405,832 | 26,244,286 | 1.0311 | 27,059,384 |
| Large Use - Regular | 278,014,229 | 1.0045 | 279,265,293 | 249,082,810 | 1.0045 | 250,203,683 |
| Large Use - 3TS | 240,709,842 | 1.0045 | 241,793,036 | 237,555,713 | 1.0045 | 238,624,714 |
| | 791,619,079 | | 804,241,479 | 750,493,261 | | 760,877,961 |

| Class B | 2019 | | | 2020 | | |
|---|---|---|---|---|---|---|
| Customer | | | | | | |
| Class Name | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) |
| Residential | 562,297,710 | 1.0377 | 583,496,333 | 555,916,913 | 1.0311 | 573,182,636 |
| General Service < 50 kW | 198,127,913 | 1.0377 | 205,597,336 | 195,457,487 | 1.0311 | 201,528,025 |
| General Service 50 to 4999 kW | 668,556,159 | 1.0377 | 693,760,726 | 647,015,207 | 1.0311 | 667,110,270 |
| General Service 3000-4999 kW | 0 | 1.0377 | - | 0 | 1.0311 | 0 |
| Unmetered Scattered Load | 2,230,745 | 1.0377 | 2,314,844 | 2,221,924 | 1.0311 | 2,290,933 |
| Sentinel Lighting | 754,991 | 1.0377 | 783,454 | 735,308 | 1.0311 | 758,146 |
| Street Lighting | 6,415,192 | 1.0377 | 6,657,045 | 6,419,124 | 1.0311 | 6,618,490 |
| Large Use - Regular | 36,588,271 | 1.0045 | 36,752,918 | 32,780,730 | 1.0045 | 32,928,243 |
| Large Use - 3TS | 0 | 1.0045 | - | 0 | 1.0045 | 0 |
| **TOTAL** | **1,474,970,980** | | **1,529,362,656** | **1,440,546,694** | | **1,484,416,743** |

| Total | 2019 | | | 2020 | | |
|---|---|---|---|---|---|---|
| Customer | | | | | | |
| Class Name | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) | kWh Volume (Load Forecast) | Loss Factor | kWh Volume (Loss Adjusted - Appendix 2-Z) |
| Residential | 562,297,710 | | 583,496,333 | 555,916,913 | | 573,182,636 |
| General Service < 50 kW | 198,127,913 | | 205,597,336 | 195,457,487 | | 201,528,025 |
| General Service 50 to 4999 kW | 914,077,329 | | 948,538,045 | 884,625,659 | | 912,100,451 |
| General Service 3000-4999 kW | 27,373,838 | | 28,405,832 | 26,244,286 | | 27,059,384 |
| Unmetered Scattered Load | 2,230,745 | | 2,314,844 | 2,221,924 | | 2,290,933 |
| Sentinel Lighting | 754,991 | | 783,454 | 735,308 | | 758,146 |
| Street Lighting | 6,415,192 | | 6,657,045 | 6,419,124 | | 6,618,490 |
| Large Use - Regular | 314,602,500 | | 316,018,211 | 281,863,540 | | 283,131,926 |
| Large Use - 3TS | 240,709,842 | | 241,793,036 | 237,555,713 | | 238,624,714 |
| **TOTAL** | **2,266,590,060** | | **2,333,604,135** | **2,191,039,956** | | **2,245,294,704** |
| | | | | | | |
| Large Use-FA | 40,897,737 | 1.0045 | 41,081,777 | 39,835,651 | 1.0045 | 40,014,911 |
| | | | | | | |
| **TOTAL (Incl. Large Use-FA)** | **2,307,487,797** | | **2,374,685,912** | **2,230,875,607** | | **2,285,309,615** |

# Commodity Expense

***Step 1:*** **Allocation of Commodity** — **2018 Historical Actuals**

| Customer Class Name | | Last Actual kWh's | Class A kWh | Class B kWh | non-RPP: non GA mod | non-RPP: GA mod | non-RPP: Total | RPP | Proportions (by Class): non-RPP % | Proportions (by Class): RPP % | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | | 636,799,631 | - | 636,799,631 | - | 17,881,940 | 17,881,940 | 618,917,691 | *2.81%* | *97.19%* | |
| General Service < 50 kW | | 203,075,208 | - | 203,075,208 | - | 28,255,259 | 28,255,259 | 174,819,949 | *13.91%* | *86.09%* | |
| General Service 50 to 4,999 kW | | 925,847,386 | 226,962,795 | 698,884,591 | 471,551,018 | 46,561,900 | 518,112,918 | 180,771,673 | *55.96%* | *19.52%* | |
| General Service 3000-4999 kW | | 41,120,567 | 41,120,567 | 0 | - | - | - | 0 | *0.00%* | *0.00%* | |
| Unmetered Scattered Load | | 2,266,364 | - | 2,266,364 | 2,175,835 | - | 2,175,835 | 90,530 | *96.01%* | *3.99%* | |
| Sentinel Lightinç | | 768,232 | - | 768,232 | - | 66,012 | 66,012 | 702,220 | *8.59%* | *91.41%* | |
| Street Lighting | | 6,467,781 | - | 6,467,781 | 6,449,455 | - | 6,449,455 | 18,326 | *99.72%* | *0.28%* | |
| Large Use - Regular | | 201,820,265 | 173,583,531 | 28,236,734 | 28,236,734 | - | 28,236,734 | -0 | *13.99%* | *0.00%* | |
| Large Use - 3TS | | 172,633,300 | 172,633,300 | - 0 | - | - | - | -0 | *0.00%* | *0.00%* | |
| **TOTAL** | | **2,190,798,735** | **614,300,194** | **1,576,498,541** | **508,413,042** | **92,765,111** | **601,178,153** | **975,320,388** | | | |
| *%* | | *100.00%* | | *100.00%* | *32.25%* | *5.88%* | | *61.87%* | *38.13%* | *61.87%* | *100.00%* |

***Step 2:*** **Forecasted Commodity Prices**

***Step 2a:*** **GA Modifier** ($/MWh) — non-RPP: $ (41.49) Source: RPP-GA-Modifier-Report-20190417, Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

***Step 2b:*** **Forecasted Commodity Prices** Table ES-1: Average RPP Supply Cost Summary**

Source: RPP-Supply-Cost-Report- May 1, 2019 - April 30, 2020 , page 2 average market price for electricity used by RPP consumer

| | | | non-RPP: non GA mod | non-RPP: GA mod | RPP |
|---|---|---|---|---|---|
| HOEP ($/MWh) | ~~Load-Weighted Price for RPP Consumers~~ | | $20.68 | $20.68 | |
| Global Adjustment ($/MWh) | Impact of the Global Adjustment | | $102.22 | $60.73 | |
| Adjustments ($/MWh) | | | $1.00 | $1.00 | |
| **TOTAL ($/MWh)** | Average Supply Cost for RPP Consumers | | **$123.90** | **$82.41** | **$82.41** |
| ***$/kWh*** | | | ***$0.12390*** | ***$0.08241*** | ***$0.08241*** |
| Percentage shares (%) | non-RPP (GA mod/non-GA mod), RPP | | 32.25% | 5.88% | 61.87% |
| **WEIGHTED AVERAGE PRICE ($/kWh)** | **(Sum of I43, J43 and L43)** | $ 0.0958 | **$0.0400** | **$0.0048** | **$0.0510** |

***Step 3:*** **Commodity Expense**
*(volumes for the bridge and test year are loss adjusted)*

**Class A**

| Customer | | Revenue | Expense | 2019 kWh Volume | 2019 kW Volume | 2019 HOEP Rate/kWh | 2019 Avg GA/kW | 2019 Amount | 2020 kWh Volume | 2020 kW Volume | 2020 HOEP Rate/kWh | 2020 Avg GA/kW | 2020 Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Service 50 to 4,999 kW | | 4035 | 4705 | ###54.;72.:3 | 508,003 | 0.02068 | 33.05 | $21,607,884 | ###53.6;3.89 | 505,275 | 0.02068 | 33.05 | $21,487,567 |
| General Service 3000-4999 kW | | 4015 | 4705 | ###64.2:6.45 | 126,275 | 0.02068 | 33.05 | $5,043,937 | ###62.;::.39 | 126,150 | 0.02068 | 33.05 | $5,017,142 |
| Large Use - Regular | | 4020 | 4705 | ###9;.62;.43 | 307,953 | 0.02068 | 33.05 | $13,888,627 | ###54.6:3.56 | 249,725 | 0.02068 | 33.05 | $10,993,608 |
| Large Use - 3TS | | 4020 | 4705 | ###8:.966.73 | 312,480 | 0.02068 | 33.05 | $13,817,690 | ###8:.53;.:2 | 305,377 | 0.02068 | 33.05 | $13,574,136 |
| | | | | 623,188,776 | 1,254,711 | | | $54,358,137 | 573,281,001 | 1,186,527 | | | $51,072,454 |

**Class B**

| Customer | | Revenue | Expense | 2019 | | | | | 2020 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Class Name | UoM | USA # | USA # | Volume | rate ($/kWh): | | | Amount | Volume | rate ($/kWh): | | | Amount |
| Residential | kWh | 4006 | 4705 | 611,741,252 | $ 0.0958 | | | $58,598,891 | 608,993,590 | $0.0958 | | | $58,335,692 |
| General Service < 50 kW | kWh | 4010 | 4705 | 209,869,780 | 0.0958 | | | $20,103,494 | 206,559,079 | $0.0958 | | | $19,786,361 |
| General Service 50 to 4,999 kW | kWh | 4035 | 4705 | 717,323,439 | 0.0958 | | | $68,712,643 | 712,830,344 | $0.0958 | | | $68,282,248 |
| General Service 3000-4999 kW | kWh | 4015 | 4705 | 0 | 0.0958 | | | $0 | 0 | $0.0958 | | | $0 |
| Unmetered Scattered Load | kWh | 4010 | 4705 | 2,317,238 | 0.0958 | | | $221,969 | 2,268,565 | $0.0958 | | | $217,307 |
| Sentinel Lighting | kWh | 4030 | 4705 | 777,340 | 0.0958 | | | $74,462 | 753,129 | $0.0958 | | | $72,142 |
| Street Lighting | kWh | 4025 | 4705 | 6,719,922 | 0.0958 | | | $643,703 | 6,685,173 | $0.0958 | | | $640,375 |
| Large Use - Regular | kWh | 4020 | 4705 | 29,184,395 | 0.0958 | | | $2,795,583 | 21,550,665 | $0.0958 | | | $2,064,345 |
| Large Use - 3TS | kWh | 4020 | 4705 | -0 | 0.0958 | | | $0 | -0 | $0.0958 | | | $0 |
| **TOTAL** | | | | **1,577,933,366** | | | | **$151,150,744** | **1,559,640,544** | | | | **$149,398,470** |

**Total**

| Customer | | Revenue | Expense | 2019 | | | | | 2020 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Class Name | UoM | USA # | USA # | Volume | avg rate ($/kWh): | | | Amount | Volume | avg rate ($/kWh): | | | Amount |
| Residential | kWh | 4006 | 4705 | 611,741,252 | 0.0958 | | | $58,598,891 | 608,993,590 | 0.0958 | | | $58,335,692 |
| General Service < 50 kW | kWh | 4010 | 4705 | 209,869,780 | 0.0958 | | | $20,103,494 | 206,559,079 | 0.0958 | | | $19,786,361 |
| General Service 50 to 4,999 kW | kWh | 4035 | 4705 | 950,274,251 | 0.0950 | | | $90,320,526 | 944,322,022 | 0.0951 | | | $89,769,815 |
| General Service 3000-4999 kW | kWh | 4015 | 4705 | 42,084,237 | 0.1199 | | | $5,043,937 | 40,988,172 | 0.1224 | | | $5,017,142 |
| Unmetered Scattered Load | kWh | 4010 | 4705 | 2,317,238 | 0.0958 | | | $221,969 | 2,268,565 | 0.0958 | | | $217,307 |
| Sentinel Lighting | kWh | 4030 | 4705 | 777,340 | 0.0958 | | | $74,462 | 753,129 | 0.0958 | | | $72,142 |
| Street Lighting | kWh | 4025 | 4705 | 6,719,922 | 0.0958 | | | $643,703 | 6,685,173 | 0.0958 | | | $640,375 |
| Large Use - Regular | kWh | 4020 | 4705 | 208,593,609 | 0.0800 | | | $16,684,209 | 154,032,009 | 0.0848 | | | $13,057,953 |
| Large Use - 3TS | kWh | 4020 | 4705 | 168,744,513 | 0.0819 | | | $13,817,690 | 168,319,806 | 0.0806 | | | $13,574,136 |
| **TOTAL** | | | | **2,201,122,142** | | | | **$205,508,882** | **2,132,921,546** | | | | **$200,470,924** |

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – October 31, 2019*

*** Regulated Price Plan Cost Supply Report May 1, 2019 - April 30, 2020*

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Reference:

Exhibit 2, Page 57

Preamble:

EnWin Utilities provides the reconciliation of DSP additions to fixed assets additions in the following table:

| Line No. | Reconciliation | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Actual | 2013 Actual | 2014 Actual |
|---|---|---|---|---|---|---|---|
| 1 | Total Additions per DSP | $17,775,511 | $24,843,638 | $17,682,992 | $17,082,682 | $19,013,849 | $18,793,873 |
| 2 | Contributions in Kind | (520,301) | (224,159) | (321,196) | (1,510,636) | (998,221) | (2,403,163) |
| 3 | Spare Transformer Adjustment | - | - | - | (276,563) | 3,225 | (96,348) |
| 4 | Vehicle Additions | - | - | - | - | - | - |
| 5 | **Net DSP Additions** | **$17,255,209** | **$24,619,479** | **$17,361,796** | **$15,295,483** | **$18,018,854** | **$16,294,362** |
| 6 | Additions per Fixed Asset Continuity | $10,156,939 | $25,417,381 | $13,049,669 | $11,913,591 | $ 9,901,515 | $34,238,456 |
| 7 | Less Work in Progress Disposals | 7,092,908 | (7,096,508) | 896,068 | 3,221,275 | 8,117,338 | (8,140,395) |
| 8 | Smart Meter Additions (Disposition) | 5,362 | 6,298,606 | 3,416,060 | 160,617 | - | (9,803,699) |
| 9 | **Net Fixed Asset Additions** | **$17,255,209** | **$24,619,479** | **$17,361,796** | **$15,295,483** | **$18,018,854** | **$16,294,362** |

| Line No. | Reconciliation | 2015 Actual | 2016 Actual | 2017 Actual | 2018 Forecast | 2019 Bridge Year | 2020 Test Year |
|---|---|---|---|---|---|---|---|
| 1 | Total Additions per DSP | $20,914,948 | $14,605,089 | $15,452,244 | $15,587,598 | $23,632,230 | $21,598,360 |
| 2 | Contributions in Kind | (4,322,469) | (411,579) | (2,216,539) | (1,888,586) | (4,898,000) | (3,251,860) |
| 3 | Spare Transformer Adjustment | 192,283 | 43,322 | 199,942 | 9,761 | - | - |
| 4 | Vehicle Additions | - | - | - | 823,917 | 2,346,808 | 1,814,576 |
| 5 | **Net DSP Additions** | **$16,784,762** | **$14,236,832** | **$13,435,647** | **$14,532,690** | **$21,081,038** | **$20,161,076** |
| 6 | Additions per Fixed Asset Continuity | $18,276,316 | $16,831,839 | $13,709,114 | $14,524,357 | $21,081,038 | $20,161,076 |
| 7 | Less Work in Progress Disposals | (1,491,554) | (2,595,007) | (313,349) | 8,333 | - | - |
| 8 | MIST Meter Additions | - | - | 39,882 | - | - | - |
| 9 | **Net Fixed Asset Additions** | **$16,784,762** | **$14,236,832** | **$13,435,647** | **$14,532,690** | **$21,081,038** | **$20,161,076** |

Question:

a) Please explain the line of “Work in Progress Disposal” and confirm whether or not it represents the construction work in progress (CWIP)?

i) If so, please explain why the CWIP was not forecasted in the year of 2019 and 2020?

Response:

a) ENWIN confirms that “Work in Progress Disposal” represents changes to construction work in progress (CWIP) or assets under construction (AUC).

i. CWIP or AUC is not budgeted since, at the time the budget is being developed, it is not known whether the various projects will be in-service by the end of the budget year.

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Reference:

Exhibit 2, Page 59; Attachment 2-E Capitalization Policy

Preamble:

EnWin Utilities states that it "further revised its capitalization policy effective March 1, 2019 to increase the threshold for capitalization from $1,000 to $2,000 and provide additional guidance." Staff notes that the additional guidance is provided in the Attachment 2-E Capitalization policy as below:

Individual expenditures greater or equal to $2,000 are eligible for capitalization. Transactions that do not meet this threshold should be charged to an expense account and not capitalized.

The exception to the capitalization dollar limit is meters and desktop/laptops. Those assets may have individual costs including labour and setup costs below the $2,000 threshold however their useful life and future economic benefit support that they are capital assets.

Question:

a) Please provide the rationale for this threshold change of capitalization policy.

b) Please provide the estimated impact of this change on the 2019 and 2020 capital expenditures.

---

Response:

a) ENWIN conducted a review of other LDC's capitalization policies and noted that the capitalization threshold ranged from $1,000 - $5,000 based on the type of expenditure. ENWIN chose to adjust its capitalization threshold from $1,000 to $2,000 to be consistent with others within the industry.

b) There is no material impact anticipated on the future capital expenditures as most of the capitalized items were already in excess of $2,000 and the routine items, such as computers and meters, that were below the threshold were specifically identified within the policy.

## 2 - OEB Staff - 11

Reference:

Exhibit 2, Pages 59 to 61

Preamble:

EnWin Utilities explains that it capitalizes three types of overhead expenses: labour, material and trucking. The burden rates for these expenses are determined annually. EnWin Utilities provides the following comparison for the burden rates for the capitalization of the overhead:

| Burden Type | 2009 Rates | 2020 Rates |
|---|---|---|
| Labour | 117.70% | 66.20% |
| Material | 16.00% | 5.81% |
| Trucking | | |
| Class 4 Vehicles – Cars | $ 8.36 | $ 4.53 |
| Class 5 Vehicles – Vans & Pick-up Trucks | $ 8.44 | $ 5.07 |
| Class 6 Vehicles – Dump & Utility Trucks | $ 16.11 | $ 8.35 |
| Class 7 Vehicles – Bucket Trucks | $ 44.85 | $ 25.06 |
| Class 8 Vehicles – Specialty Vehicles | $ 14.20 | $ 11.97 |
| Class 9 Vehicles – Trailers | $ 14.97 | $ 2.42 |

Question:

a) Please provide the burden rates in 2011 which was the IFRS transition year for EnWin Utilities.

b) Please explain why the labour burden rate in 2009 was 117.70% which was greater than 100%.

Response:

a) ENWIN has provided the table below, which shows the burden rates for 2011 for both CGAAP and IFRS.

| Burden Type | 2009 Rates CGAAP | 2011 Rates CGAAP | 2011 Rates IFRS | 2020 Rates IFRS |
|---|---|---|---|---|
| Labour | 117.70% | 119.60% | 104.96% | 66.20% |
| Material | 16.00% | 13.00% | 8.00% | 5.81% |
| Trucking: | | | | |
| Class 4 Vehicles - Cars | $ 8.36 | $ 4.61 | $ 2.82 | $ 4.53 |
| Class 5 Vehicles - Vans & Pick-up Trucks | $ 8.44 | $ 6.58 | $ 4.76 | $ 5.07 |
| Class 6 Vehicles - Dump & Utility Trucks | $ 16.11 | $ 11.44 | $ 8.90 | $ 8.35 |
| Class 7 Vehicles - Bucket Trucks | $ 44.85 | $ 38.51 | $ 27.92 | $ 25.06 |
| Class 8 Vehicles - Specialty Vehicles | $ 14.20 | $ 10.76 | $ 7.76 | $ 11.97 |
| Class 9 Vehicles - Trailers | $ 14.97 | $ 12.05 | $ 11.43 | $ 2.42 |

b) The labour burden rate in 2009 was 117.70%. In 2009, ENWIN's labour burden was calculated under CGAAP and accordingly included employee benefits, non-productive time (including training), supervision, management and engineering time. As noted in Exhibit 2, under IFRS, only costs deemed to be directly attributable to capital projects are now included in the labour burden calculation. Costs such as training, professional and technical fees, management, engineering and other costs not directly attributable to capital projects have been removed from the annual labour burden calculation.

## 2 - OEB Staff - 12

Reference:

Appendix 2-D Overhead Expense

Preamble:

OEB staff notes that the total OM&A before capitalization in EnWin Utilities' Appendix 2-D Overhead expense is the total OM&A expense by categories plus the labour burden, material burden and truck burden that are capitalized.

Question:

a) Please refile the Appendix 2-D by providing the total OM&A expenses before capitalization using the total labour expense, total material expenses and total truck expenses for the year and then compare to the expenses that are capitalized.

Response:

Appendix 2-D has been refiled to include 2018 actuals and provide the total OM&A before capitalization using total labour, material and trucking expenses for each year and compared to the expenses that are capitalized.

## 2 - OEB Staff - 13

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 4

Exhibit 2: Rate Base, Attachment 2A, Page 8

Exhibit 2: Rate Base, Attachment 2A, Page 12

Preamble:

EnWin Utilities provides Table 1 as below:

**Table 1 Historical and forecast capital expenditures and system O&M**

| Category | Historical ($ '000) | | | | | Forecast ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| System Access | $ 2,762 | $ 3,946 | $ 3,963 | $ 3,310 | $ 7,267 | $ 6,205 | $ 3,476 | $ 3,526 | $ 3,577 | $ 3,628 |
| System Renewal | $ 8,221 | $ 5,475 | $ 5,456 | $ 5,586 | $ 7,289 | $ 8,440 | $ 8,009 | $ 7,605 | $ 7,850 | $ 7,366 |
| System Service | $ 6,433 | $ 2,931 | $ 3,976 | $ 4,427 | $ 4,221 | $ 3,537 | $ 3,622 | $ 3,610 | $ 3,986 | $ 3,623 |
| General Plant | $ 3,499 | $ 2,253 | $ 2,058 | $ 3,098 | $ 7,507 | $ 5,021 | $ 4,283 | $ 3,856 | $ 4,174 | $ 4,213 |
| Total (Gross) | $ 20,915 | $ 14,605 | $ 15,452 | $ 16,421 | $ 26,284 | $ 23,203 | $ 19,390 | $ 18,597 | $ 19,587 | $ 18,830 |
| Contributed Capital | $ 4,322 | $ 412 | $ 2,217 | $ 1,889 | $ 4,898 | $ 3,252 | $ 813 | $ 823 | $ 834 | $ 844 |
| Total (Net) | $ 16,592 | $ 14,194 | $ 13,236 | $ 14,532 | $ 21,386 | $ 19,951 | $ 18,577 | $ 17,774 | $ 18,753 | $ 17,986 |
| System O&M | $ 4,398 | $ 4,631 | $ 9,757 | $ 9,825 | $ 10,942 | $ 10,904 | $ 11,049 | $ 11,068 | $ 11,102 | $ 11,096 |

In reference to its capital spending on automation programs, EnWin Utilities states that:

System Service spending was comparatively higher during the Historical Period compared to the Forecast Period mainly due to the completion of a substantial portion of ENWIN's grid automation program.

In reference to its O&M spending resulting from automation, EnWin Utilities states that:

The continuation of the grid modernization … is expected to automate operations and minimize truck dispatches, while minimizing outages and reducing restoration times. To date, ENWIN's implementation of such automation has facilitated workforce reduction without compromising reliability.

Question:

a) Following the step change in System O&M costs between 2016 & 2017 that EnWin Utilities explains was due to reapportioning costs from Administration to System O&M, System O&M costs are forecast to further increase by almost 14% from 2017 to 2024 despite EnWin Utilities stating that its past and forecast investments in system automation are expected to produce ongoing O&M savings. Please explain why the System O&M spending forecast does not appear to show any savings due to automation. Has EnWin Utilities already realized all (or most) O&M cost savings attributable to past and future system automation investments?

i. If yes, please show where in the Historical Period these savings are accounted.
ii. If no, please explain why there are no savings in the Forecast Period.

b) Net capital spending is forecast to increase by over 47% from $14,532,000 in 2018 to $21,386,000 in 2019. Although forecast capital spending over each year of the test period is lower than in 2019, capital spending never returns to historical spending levels. Given that EnWin Utilities does not forecast significant load growth and EnWin Utilities' reliability performance is not trending unfavourably, what are the primary factors driving this structural capital spending increase?

---

Response:

a) From 2017 through the forecast period there were O&M drivers which acted to reduce O&M costs and others which acted to increase O&M costs. The result is a net increase in costs.

Drivers that reduced O&M costs include:

1. SCADA and remote devices pinpoint trouble enabling dispatch of a single crew to find the source of the problem, thereby saving labour and trucking costs
2. SCADA and remote devices effecting remote switching saving truck rolls to operate the system
3. Data collection on tablets reducing transcribing time from paper to computer systems and resolving errors thereby saving clerical time. This is somewhat

offset by increased IT time to troubleshoot devices. ENWIN has been slowly adding applications and will continue to do so, so savings are distributed over longer period

4. Use of Apprentices and students to do pole inspections resulted in lower labour costs however this was a temporary measure and is not sustainable.
5. Temporary workforce reductions have saved dollars in training and other non-productive costs which impact O&M totals.
6. Reduction in cellular data costs have saved money however this is more than offset from the addition of equipment that requires communication
7. Arranged Apprentice training from IHSA in Chatham rather than Toronto which saved money in expenses and lodging. This was partly off-set by an increased number of retirements resulting in increased training costs for new staff

Drivers increasing O&M costs include:

1. Increased use of system automation resulting in an increase in communication costs and more complex devices to maintain which requires more maintenance with more highly trained staff
2. Staff wages have increased with inflation
3. Combining overhead and underground work classification will result in higher wage costs but this will be offset by capital cost reductions due to efficiencies gained from needing only one work classification at a job
4. Increased wood pole drilling and treatment and increased concrete pole treatment which will eventually be offset by a longer service life for the assets
5. Tree trimming contract costs have increased only slightly from the 3-year ending in 2017 contract to the 3-year contract ending in 2020, however our contractor advised that costs were going to increase substantially in the current contract unless we changed the work. In order to limit the expected increase, we removed trimming around overhead service wires from the work specification and now only trim around services at customer's request. In this respect, the level of service provided has been reduced in order to save costs.
6. Changes to federal regulations regarding the use of drones now prohibits ENWIN from using drones to do aerial equipment inspections. What used to be accomplished using one person and a pick-up truck now takes 2 people in

a bucket truck, which more than doubles ENWIN's cost to perform inspections.

7. More rigorous data inspections are done now in order to be more data driven in our plans for capital investment than in the past which has increased the cost to perform these inspections and to analyze the results.
8. MTS maintenance has increased substantially due to the age of the stations. The four automotive stations are nearly the same vintage and all are experiencing equipment failures of the same type (controls, automation, communications) at the same time which has driven station O&M costs for these assets. As well, customer's increasing sensitivity to power quality has resulted in ENWIN needing to maintain the automotive stations in more compressed time frames which also drives costs upward.
9. An increased level of staff retirement has resulted in the hiring of apprentice line staff which carries a higher level of training and a lower level of productivity and hence a higher impact to O&M costs.

b) The <u>actual</u> net capital spending from 2018 was greater than forecast at $16,533,000 for a net capital spending increase of 29% from 2018 to $21,386,000 in 2019.

System Access expenditures less capital contributions were up in 2019 forecast over 2018 actuals by $1,818k. The largest part of the increase was for planned City roadwork project which are only partly subsidized by the City. The gross spend in that category is planned to increase from $506k to $3,886k or $3,380.

System Renewal expenditures are forecast to increase in 2019 by $937k. The largest increase is in pole replacements where only $2,151k was spent in 2018 and $2,950 is budgeted for 2019 for a difference of $799k.

System Service expenditures were forecast to be lower in 2019 by $828k.

General Plant expenditures were forecast to be $4,885k in 2019 compared to $1,487 in 2018 or an increase of $3,398k. There were two drivers for this increase. The first driver was the consolidation of offices between the Ouellette and Rhodes Drive locations for an increase of $2,402k and an increase in software system expenditures of $1,514 for CIS and other upgrades.

The site consolidation is the driver for the largest portion of the increase in expenditures between 2018 and 2019 and it will continue to be a driver of costs in 2020 as well. Thereafter, the Ouellette office will be closed and site expenditures should drop to normal levels.

## 2 - OEB Staff - 14

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 5

Preamble:

EnWin Utilities states the following:

In 2018, ENWIN changed its fleet practice to purchase rather than lease vehicles (as further explained in Section 5.4.3.1 (a) of the DSP). This change is reflected in the expenditures for years 2018 and 2019 in the Historical Period, as well as all five years of the Forecast Period, and this, as well as cost inflation, has contributed toward increasing the percent change between the two periods.

Question:

a) Does EnWin Utilities intend to purchase rather than lease all required vehicle replacements going forward? If yes, why?

b) Has EnWin Utilities prepared a business case that demonstrates benefits to ratepayers of making the change from leased to owned vehicles?

i. If yes, please provide the business case documentation.

ii. If no, please explain why a business case was not done, and provide the alternative basis supporting the decision to change the historical practice.

Response:

a) Based on current market conditions, ENWIN intends to purchase vehicles rather than lease into the future, until such time where market conditions change, at which point another review will be conducted.

b) ENWIN investigated this topic of lease compared to purchasing vehicles in 2017 and determined that embedded in lease rates were market rate interest rates plus additional financing markups. ENWIN was not in a position where additional borrowing was required and therefore was incurring financing charges where existing liquidity could be used instead to finance the purchases. Other factors such as buy out fees and monthly administrative fees could also be avoided if leases were no longer used. ENWIN provided the attached Board report (OEB Staff 14 - Attachment 1) along with sample calculations using different vehicles to show that purchasing vehicles was more economical to the utility and therefore the ratepayer.

# AGENDA SUBMISSION

**To:** EWU A&F Committee & Board of Directors
WUC A&F Committee & Board of Commissioners

August 21, 2017

**From:** Matt Carlini

**Re: Vehicle Lease vs Buy**

## Background

EnWin Utilities Ltd. ("EnWin") manages the vehicle fleet for both EnWin and Windsor Utilities Commission ("WUC"). Both operations require a fleet with some very specialized vehicles with purchase prices of the vehicles ranging from $25,000 - $500,000+. The current practice has been to lease instead of buying these Hydro and Water vehicles. That decision was made based on the historically low interest rates, liquidity pressures and accounting treatments.

With that said, the environment has changed; interest rates are increasing, accounting rules are changing and the pressures on cash flows are different than they were several years ago. As a result of these changing variables, a review was conducted comparing buying and leasing of these vehicles.

## Buy vs Lease – interest rate

*Profit embedded in a lease*

In a typical lease arrangement, the lessor (entity providing the financing) embeds a markup risk charge or profit component within the interest rate. The lessee (entity using the asset and making the monthly payments) receives the benefit of using an asset and not having to have the entire cash outlay all at once. The lessor is then subject to financing costs which in most cases include a premium to cover profit and other costs associated with administering the lease. Theoretically, if EnWin and WUC purchase vehicles instead of leasing them, they will not be paying those charges.

*EnWin/WUC Buy vs Lease - interest rate assumption*

Historically when a buy vs lease analysis was performed, the analysis assumed an interest rate of 4.134% which is the current cost of existing 30 year debt. Although that is the cost of historic borrowings it is not necessarily the relevant cost for future borrowings, if any applicable to financing a vehicle. If funds were borrowed for financing a vehicle, the rate would be lower than 4.134% as the duration of the loan would be approximately 5 years. However, since it is not realistic that EnWin would borrow in amounts matching vehicle cost levels, and instead vehicles would be purchased from excess cash on hand, the analysis should be based on the opportunity cost of the deposit interest earned instead of the debt interest rate. The lease vs buy decision is going to result in less interest being earned in the bank so that is the rate that should be used in the analysis.

Appendix A & B show sample calculations of the lease vs buy analysis for 2 types of leases. The analysis shows that the purchase option is the cheaper option. This intuitively makes sense given that interest earned is typically lower than interest paid.

**IFRS 16 - Leases**

The previous accounting rules under Canadian GAAP and International Financial Reporting Standard ("IFRS") differentiated between operating and capital leases. Capital leases were recorded on the balance sheet at the present value of the future lease payments with a corresponding liability for those payments. Operating leases on the other hand were treated as an operating expense and recorded when payments were made directly within the income statement.

EnWin and WUC treated their vehicle leases as operating leases and therefore did not have anything on the balance sheet related to these leases. The leases are recorded under the account "Vehicle Leasing" in EnWin and "Vehicle Leases' in WUC.

That treatment of those leases for both EnWin and WUC will be changing soon as a result of the implementation of some new accounting rules. The International Accounting Standards Board has issued IFRS 16 – Leases, which will come effect January 1, 2019. This new standard outlines the accounting treatment and disclosures for leases. Although there are many variables to consider, the overall takeaway is that this new standard will result in most leases being capitalized. Only in a few very specific circumstances will leases not be recorded on the balance sheet.

The accounting for leases within EnWin and WUC will therefore will need to change. The leases will have to be recorded on the balance sheet as a capital asset along with a corresponding liability. Regardless of whether EnWin or WUC lease or buy their vehicles the vehicle leases will need to be recorded as a capital asset. Overall, the impact to net income is expected to be negligible but the reclassification and composition will change from an operating expense and move to depreciation.

**Budget, Regulatory and Impacts to the Ratepayers**

Pending approval from the Committees and Boards, the 2018-2023 budget is going to be drafted with the assumption that we are transitioning away from leases and moving to capital purchases for vehicles. As stated earlier, the overall impact to net income should be minimal. The change will really be seen in the capital expenditures and the reclassification of expenses away from OM&A (Vehicle leasing) and into depreciation expense. This should therefore improve the Operating Income/EBITDA but Net Income should be the same.

The change from leasing to purchasing should be beneficial to the ratepayers because the cost of the overall vehicle costs over the life of the vehicle should be lower if we can avoid the financing charges embedded in leases.

From a cash flow perspective, as EWU and WUC migrate to vehicle purchases from leasing it is expected additional net funds of $500 thousand to $1.2 million will be required initially. Once transitioned there will be no long term differences in cash flow as existing leases expire.

**Conclusion**

It is currently more economical for the ratepayers if EnWin and WUC begin to purchase the vehicles instead of leasing them given the current circumstances. The plan at this point is to run out the remaining leases and then start purchasing all new vehicle acquisitions. Cash flows will be managed for each entity when making buying decisions and the normal evaluation and procurement procedures will be followed when acquiring new vehicles.

**Recommendation**:

**EWU and WUC Audit & Finance Committees**

That the Vehicle Lease vs Buy Report be received:

And that the Vehicle Lease vs Buy Report be recommended to the EWU Board of Directors and Windsor Utilities Commission for receipt

**EWU Board of Directors and Windsor Utilities Commission**

That the Vehicle Lease vs Buy Report be received.

Director, Finance

Vice President, Finance and CFO

President and CEO

Appendix A – Lease vs Buy Analysis – Example #1

Appendix B – Lease vs Buy Analysis – Example #2

ENWIN

WINDSOR UTILITIES COMMISSION

**Appendix A**

## Lease versus Buy Analysis

**NAME OF PROJECT** — **Class 7 Vehicle (#7142)**

***Inputs:***

| | Lease | | | |
|---|---|---|---|---|
| **Monthly Lease Payment (excluding HST)** | principle + interest | | **Purchase Price** | $298,477 |
| **Lease Term** | 96 | months | **Estimated Useful Life** | 9 |
| **Interest/ Discount Rate (bank rate)** | 1.0% | | **Salvage Value at End of Life** | 55,000 |

**Description**

**This is an actual vehicle currently being leased by EWU. The structures of the leases can vary but in this example, the monthly payment varies and is based on a depreciation (principal amount) + a $10 management fee + interest. Payments therefore decline over time. This particular lease has an interest rate of 0.335%**

**PRESENT VALUE LEASE COSTS CALCULATION**

| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Cash Flows: | | | | | | | | | | |
| Lease Payments | | 48,741 | 47,241 | 45,741 | 44,241 | 42,742 | 41,242 | 39,742 | 38,242 | - |
| Salvage Value | | | | | | | | | | (55,000) |
| **Total Cash flow** | - | 48,741 | 47,241 | 45,741 | 44,241 | 42,742 | 41,242 | 39,742 | 38,242 | (55,000) |
| **Present Value factor** | 100% | 99% | 98% | 97% | 96% | 95% | 94% | 94% | 93% | 92% |
| **Present Value of Lease Payment** | - | 48,282 | 46,356 | 44,462 | 42,599 | 40,768 | 38,967 | 37,197 | 35,456 | (50,513) |
| **Cumulative Present Value of Lease Payments** | - | 48,282 | 94,639 | 139,101 | 181,700 | 222,468 | 261,435 | 298,632 | 334,088 | 283,575 |

**Present Value of Lease Payments** — 283,575

**PRESENT VALUE PURCHASE OPTION CALCULATION**

| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Cash Flows: | | | | | | | | | | |
| Capital Costs | 298,477 | | | | | | | | - | - |
| Salvage Value | | | | | | | | | | (55,000) |
| **Total Cash flow** | 298,477 | - | - | - | - | - | - | - | - | (55,000) |
| **Present Value factor** | 100% | 99% | 98% | 97% | 96% | 95% | 94% | 94% | 93% | 92% |
| **Present Value of Purchase** | 298,477 | - | - | - | - | - | - | - | - | (50,513) |
| **Cumulative Present Value of Purchase** | 298,477 | 298,477 | 298,477 | 298,477 | 298,477 | 298,477 | 298,477 | 298,477 | 298,477 | 247,964 |

**Present Value of Purchase Option** — 247,964

**Recommendation:** **PURCHASE**

WINDSOR UTILITIES COMMISSION

**Appendix B**

## Lease versus Buy Analysis

**NAME OF PROJECT** **Class 5 Vehicle (#5054)**

***Inputs:***

| | Lease | | | |
|---|---|---|---|---|
| **Monthly Lease Payment (excluding HST)** | $ 564 | | **Purchase Price** | $ 36,324 |
| **Lease Term** | 60 | months | **Estimated Useful Life** | 9 |
| **Interest/ Discount Rate (bank rate)** | 1.0% | | **Salvage Value at End of Life** | 5,000 |

**Description**

**This is an actual vehicle currently being leased by WUC. The structures of the leases can vary but in this example, the monthly payment is consistent and there is a buy out of $7,265 at the end of the 60 month term.**

**PRESENT VALUE LEASE COSTS CALCULATION**

| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Cash Flows: | | | | | | | | | | |
| Lease Payments | | 6,769 | 6,769 | 6,769 | 6,769 | 6,769 | 7,265 | | | |
| Salvage Value | | | | | | | | | | (5,000) |
| **Total Cash flow** | - | 6,769 | 6,769 | 6,769 | 6,769 | 6,769 | 7,265 | - | - | (5,000) |
| **Present Value factor** | 100% | 99% | 98% | 97% | 96% | 95% | 94% | 94% | 93% | 92% |
| **Present Value of Lease Payment** | - | 6,705 | 6,642 | 6,579 | 6,518 | 6,456 | 6,864 | - | - | (4,592) |
| **Cumulative Present Value of Lease Payments** | - | 6,705 | 13,347 | 19,926 | 26,444 | 32,900 | 39,764 | 39,764 | 39,764 | 35,172 |

| | |
|---|---|
| **Present Value of Lease Payments** | 35,172 |

**PRESENT VALUE PURCHASE OPTION CALCULATION**

| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Cash Flows: | | | | | | | | | | |
| Capital Costs | 36,324 | | | | | | | | | |
| Salvage Value | | | | | | | | | | (5,000) |
| **Total Cash flow** | 36,324 | - | - | - | - | - | - | - | - | (5,000) |
| **Present Value factor** | 100% | 99% | 98% | 97% | 96% | 95% | 94% | 94% | 93% | 92% |
| **Present Value of Purchase** | 36,324 | - | - | - | - | - | - | - | - | (4,592) |
| **Cumulative Present Value of Purchase** | 36,324 | 36,324 | 36,324 | 36,324 | 36,324 | 36,324 | 36,324 | 36,324 | 36,324 | 31,732 |

| | |
|---|---|
| **Present Value of Purchase Option** | 31,732 |

**Recommendation:** **PURCHASE**

## 2 - OEB Staff - 15

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 4

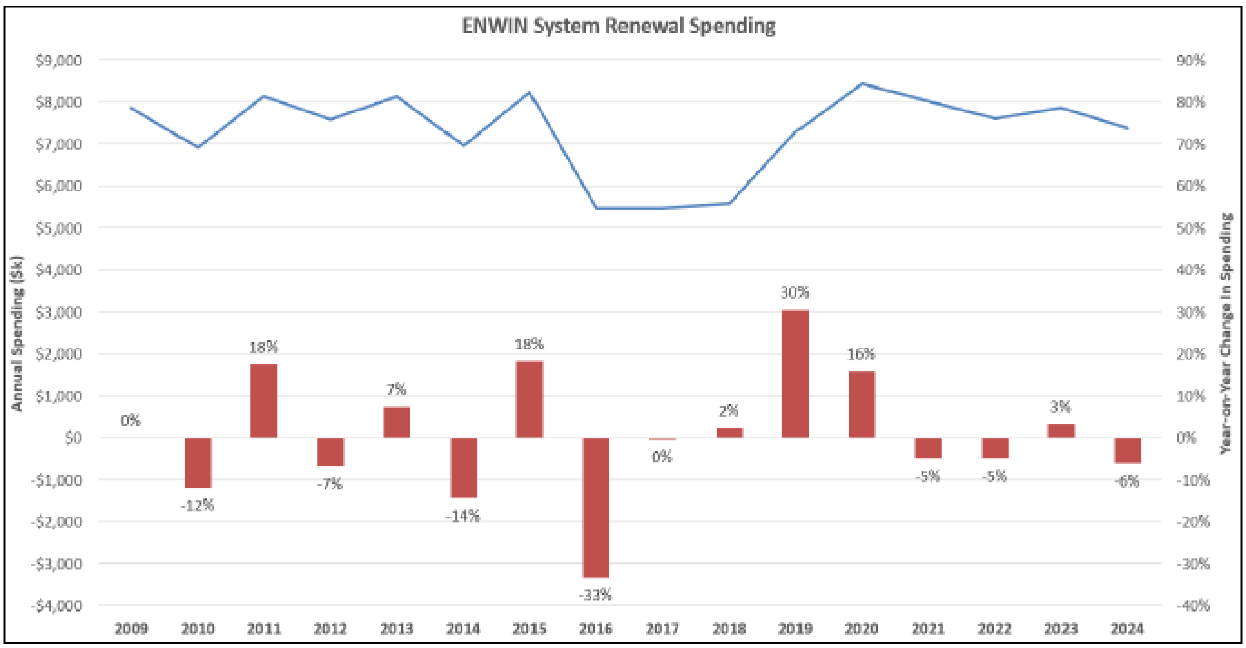
Exhibit 2: Rate Base, Attachment 2A, Page 7

Preamble:

EnWin Utilities states that:

Overall, ENWIN's investment in System Renewal has been relatively consistent year over year and is projected to remain so through the DSP prospective.

Based on the system renewal spending presented in Table 1, staff created the following graph:




Question:

Please explain why the inter-annual changes presented in the graph above should be described as "relatively consistent".

Response:

ENWIN described the inter-annual changes as “relatively consistent” as a judgment regarding the year-over-year variation in spending. While there have been changes in investment from year to year, the average investment for both actual and forecast spends is $7,303k with a standard deviation of $991k. In ENWIN’s judgment, this is “relatively consistent”.

## 2 - OEB Staff - 16

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 4

Exhibit 2: Rate Base, Attachment 2A, Page 7

Preamble:

EnWin Utilities provides Table 1, which shows a step increase in capital spending from pre-2019 to post-2019:

**Table 1 Historical and forecast capital expenditures and system O&M**

| Category | Historical ($ '000) | | | | | Forecast ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| System Access | $ 2,762 | $ 3,946 | $ 3,963 | $ 3,310 | $ 7,267 | $ 6,205 | $ 3,476 | $ 3,526 | $ 3,577 | $ 3,628 |
| System Renewal | $ 8,221 | $ 5,475 | $ 5,456 | $ 5,586 | $ 7,289 | $ 8,440 | $ 8,009 | $ 7,605 | $ 7,850 | $ 7,366 |
| System Service | $ 6,433 | $ 2,931 | $ 3,976 | $ 4,427 | $ 4,221 | $ 3,537 | $ 3,622 | $ 3,610 | $ 3,986 | $ 3,623 |
| General Plant | $ 3,499 | $ 2,253 | $ 2,058 | $ 3,098 | $ 7,507 | $ 5,021 | $ 4,283 | $ 3,856 | $ 4,174 | $ 4,213 |
| Total (Gross) | $ 20,915 | $ 14,605 | $ 15,452 | $ 16,421 | $ 26,284 | $ 23,203 | $ 19,390 | $ 18,597 | $ 19,587 | $ 18,830 |
| Contributed Capital | $ 4,322 | $ 412 | $ 2,217 | $ 1,889 | $ 4,898 | $ 3,252 | $ 813 | $ 823 | $ 834 | $ 844 |
| Total (Net) | $ 16,592 | $ 14,194 | $ 13,236 | $ 14,532 | $ 21,386 | $ 19,951 | $ 18,577 | $ 17,774 | $ 18,753 | $ 17,986 |
| System O&M | $ 4,398 | $ 4,631 | $ 9,757 | $ 9,825 | $ 10,942 | $ 10,904 | $ 11,049 | $ 11,068 | $ 11,102 | $ 11,096 |

EnWin Utilities states the following:

The ACA was completed by Kinectrics Inc., a category leader in providing life cycle management solutions for the electricity industry. The ACA recommends a “Flagged for Action” (“FFA”) plan of assets expected to require attention over the Forecast Period. System Renewal spending is allocated to assets with the greatest need for replacement. ENWIN has balanced the recommended FFA plan with prudence in order to achieve the desired pace of capital investment over the Forecast Period.

Question:

a) Did adoption of the Kinectrics life cycle management solution cause the 2017 to 2019 step increase in capital spending to satisfy the parameters and metrics set out under the Kinectrics program?

i. If yes, please explain what steps EnWin Utilities has taken to ensure the Kinectrics life cycle management solution was properly calibrated to ensure that any changes in spending are appropriate and necessary, given the context of historically good reliability and performance trends and a low load growth environment.

ii. If no, explain what has driven the step increase in capital spending?

---

Response:

The ACA completed by Kinectrics only partially caused the increase in capital spending. The FFA was not fully adopted but was used as a guideline to prudently achieve the desired pace of investment over the forecast period and still maintain the reliability goals and customer's expectations of maintaining a consistent level of investment throughout the years.

There were also cost increases between the 2017 Actual and the 2019 Forecast investments due to several complex and costly projects planned for the 2019. Some elements in 2019 did not exist in 2017 while others had increased levels of investment. The following are examples of budget elements with significant differences:

. MIST meters: $500k (no investment in 2017)

. Customer Vaults Sustainment: $400k (no investment in 2017)

. Submersible Sustainment Program: $465k (increase in investment due to poor performance of submersible transformers)

. Pole Sustainment Program: $390k (increase over 2017 spending which was less than budget – both 2017 and 2019 had the same budget amounts)

. Vehicles: $2.5M (change from leased vehicles in 2017 to owned vehicles in 2019)

. Site Rhodes: $2.2M (increase due to planned renovation to accommodate staff from Ouellette site)

. Information Technology: $1.1M (planned increase in budget due to new expenditures for CIS upgrade, new records management system and various other software and tool enhancements)

## 2 - OEB Staff - 17

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 9

Exhibit 2: Rate Base, Attachment 2A, Appendix B, Page 9

Preamble:

EnWin Utilities states that customers rank "maintaining" reliability as their second priority behind controlling costs:

During the consultation process, customers were given the opportunity to provide suggestions regarding how ENWIN can improve service to them. The top priority, consistent across all customer groups, was the need to deliver electricity at a reasonable price. Maintaining reliability was ranked second. Finally, customers ranked safety as a third priority.

Question:

a) Please explain if EnWin Utilities is making any investments that are expected to improve reliability, but which would not materially reduce reliability if they were not made during the forecast period?

Response:

The types of investments that have an effect on the reliability of supply to customers are System Renewal and System Enhancement investments. System Renewal investments are needed to replace existing infrastructure that is at end of life and as such, will generally maintain the same level of reliability when facing the same level of challenges that have presented in the past. System Enhancement investments have the potential to improve reliability of supply for customers or to maintain the level of reliability for customers in the face of increasing challenges due to climate change and workforce reduction.

The System Enhancement investments are aimed to provide an improved level of reliability for those customers affected most directly by the investment and will not by themselves provide a significant increase in the overall system reliability. An example of this is the Radial Branch Back-up project(s) where clusters of customers that are radially fed are provided a source of backfeed such that if an initiating event were to occur, many of those customers could be back-fed and have their power maintained through the event. In this case, there is a definite improvement in reliability for those customers if the project is constructed however the effect on overall system reliability may be small.

Another System Enhancement investment is the Feeder Ring Pilot. This project proposes to make a ring feed from the 25M7 feeder. In this configuration, a feeder fault would result in only the directly affected section being removed from service. This project will provide an increased level of reliability to those customers that are supplied from that feeder however will not have a significant effect on overall system reliability. This project is a pilot however and has the potential to prove that a different configuration of ENWIN's feeders may improve the overall system reliability.

Another System Enhancement investment in 2020 is the Prince to Brock section of the high capacity feeder that is planned to connect Malden and Crawford transformer stations. This project is being undertaken now as many of the poles in that section of line are nearing end of life and will require replacement and as such, it is an appropriate time to make this investment. This investment will assist ENWIN in effecting restoration of power to customers in the event of a total station loss. This situation occurred on May 9th when Hydro One lost both 115 kV feeds to the Crawford station as a result of a structure fire under the 115kV lines and was associated with a construction for the Gordie Howe International Bridge. This outage blacked out much of the City of Windsor's downtown core. Utilizing a high capacity line section between Crawford and Essex TS', ENWIN was able to start restoration within 10 minutes of the outage and had the majority of the customers restored within an hour. The high capacity feeder lines provide a positive improvement in reliability to those customers that may be affected by an outage. However, they may not provide an overall improvement to system reliability unless there is a precipitating incident.

In summary, the investments ENWIN is making will generally provide a significant improvement for those customers more directly affected by the construction but will have a smaller effect on overall system reliability.

## 2 - OEB Staff - 18

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 11

Preamble:

EnWin Utilities explains its asset management process as below:

ENWIN continues to implement a number of initiatives to facilitate better planning and execution of its capital and operating expenditures. The implementation of a formal Asset Management Process ("AMPRO") has allowed ENWIN to determine the most appropriate pace and level of investment for renewal of its assets. ENWIN expects to realize cost efficiencies through the reduction in unexpected replacement of equipment on premium time. ENWIN's AMPRO also balances the performance of the distribution system and customers' demand for service and reliability in determining renewal, maintenance, and improvement requirements. The DSP incorporates best practises with regard to asset management from the AMPRO.

Question:

a) Does the AMPRO project pacing recognize the opportunity costs to ratepayers of early replacement of assets with remaining service lives?
b) Please provide the discount rate and calculations utilized to derive the AMPRO pacing metrics.
c) Will ratepayers derive any short term economic or rate benefits from EnWin Utilities implementing the AMPRO methodology? Please explain in detail.
d) Please confirm that the Asset Management Process is the AMPRO CMMS (computerized maintenance management software) application provided by AMPRO Applications Pty Ltd, out of Australia.

i. If confirmed, please describe which of the following Asset Management Activities the tool is currently performing:

1) Job Scheduling
2) Job Monitoring and Recording
3) Job Budgeting
4) Job Cost Tracking
5) Inventory Control
6) Generation of Preventative Maintenance Procedures
7) Job Performance Record Keeping
8) Preparation of Preventative Maintenance Procedures
9) Scheduling of Preventative Maintenance Procedures
10) Asset condition tracking

11) Probability of Failure analysis
12) Consequence of Failure analysis
13) Asset Risk Analysis
14) Project Prioritization using either system reliability risk or asset risk analysis

ii. If not confirmed, what is the software tool, and which of the above Asset Management Activities does that tool perform?

Response:

a) In the asset management process (AMPRO), it is recognized that there is an opportunity cost for replacement of assets prior to their end of life. In this regard, it is ENWIN's goal to extend the useful life of its assets to their economic maximum in order to minimize this opportunity cost. This is affected through the identification and selection of projects for consideration. Projects involving the replacement of assets with substantial remaining life are not likely to be brought forward for consideration.

b) The pacing of investments is determined at a high level through the establishment of a budget "envelope" within which the capital and operating plans are built. The budget envelope is determined through the cost of service application and judgment, and is informed by the long-term projection of asset condition and asset life. A discount rate is not used in the determination of the pacing of investment.

c) Ratepayers are unlikely to derive short term benefit from the implementation of the AMPRO. The AMPRO provides a rational framework for identifying projects that will benefit customers and improves upon prior, less rigorous methods. Projects identified and vetted through the AMPRO will continue to impact rate base and will be reflected in rates to the extent of the depreciation of the capital and return for that project. Consequently, the economic and rate benefits will accrue over the long term rather than over the short term.

d) The AMPRO is not the AMPRO CMMS (computerized maintenance management software) application provided by AMPRO Applications Pty Ltd, out of Australia. AMPRO simply refers to ENWIN's asset management process. ENWIN uses a combination of manual processes, Excel spreadsheets and its Esri GIS and SAP ERP software solutions as follows:

| | |
|---|---|
| 1) Job Scheduling | Done manually and tracked weekly on an Excel spreadsheet |
| 2) Job Monitoring and Recording | Done manually and costs recorded in SAP |
| 3) Job Budgeting | Done manually and recorded on an Excel |

| | |
|---|---|
| | spreadsheet |
| 4) Job Cost Tracking | Cost charged to project work orders in SAP |
| 5) Inventory Control | Inventory managed in SAP |
| 6) Generation of Preventative Maintenance Procedures | Done manually |
| 7) Job Performance Record Keeping | Done manually using data from SAP |
| 8) Preparation of Preventative Maintenance Procedures | Done manually |
| 9) Scheduling of Preventative Maintenance Procedures | Maintenance schedules are produced in SAP |
| 10) Asset condition tracking | Point asset conditions are maintained in SAP while linear assets are maintained in GIS |
| 11) Probability of Failure analysis | Done manually using judgment and recorded in PROSORT (Excel spreadsheet) |
| 12) Consequence of Failure analysis | Done manually using judgment and recorded in PROSORT (Excel spreadsheet) |
| 13) Asset Risk Analysis | Done manually using judgment and recorded in PROSORT (Excel spreadsheet) |
| 14) Project Prioritization using either system reliability risk or asset risk analysis | Done manually using data from PROSORT (Excel spreadsheet) |

## 2 - OEB Staff - 19

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 12

Exhibit 2: Rate Base, Attachment 2A, Page 52

Preamble:

EnWin Utilities explains that system O&M decreased from 2009 to 2016:

To date, ENWIN's implementation of such automation has facilitated workforce reduction without compromising reliability. Section 5.4.3.1 (b) of the DSP illustrates that, despite drivers that would be expected increase system O&M, during the period from 2009 through 2016, system O&M decreased from $4,956k to $4,631k (accounting changes in 2017 made further comparisons incongruous).

EnWin Utilities further explains the reason of the substantial increase in 2017 O&M:

Total O&M per Customer

This measure shows a substantial increase in 2017 due to higher O&M costs than previous years, which was a result of a reclassification of O&M costs (specifically, a re-attribution of administrative costs from "Admin" to "System" O&M).

Question:

a) Please describe the accounting standard changes that drove this 2017 O&M Cost delta.

b) Will this change have a net impact on customer rates when compared with the prior treatment? Please explain.

---

Response:

a) The accounting change was actually a reclassification of costs, not an accounting standards change. This redistribution of costs was necessary to achieve better compliance with the Accounting Procedures Handbook (which requires fully allocated costs), and enhance comparability with other LDCs. It was determined that, prior to 2017, only direct labour was applied, which left some admin costs unapplied.

b) This change is purely a reclassification of costs and, therefore, will not have any impact on customer rates when compared with the prior treatment.

## 2 - OEB Staff - 20

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 13

Preamble:

EnWin Utilities explains its use of the portable tablets as below:

Since the cost of the work associated with the use of portable tablets is not separately tracked, it is not possible to determine with any reasonable certainty, the quantum of savings resulting from this initiative. The clerical pool has, however, been reduced from eight individuals, to five currently. However, that pool also serves ENWIN's sister company, the Windsor Utilities Commission ("WUC").

Question:

a) Please confirm whether or not the related costs regarding the portable tablets and the clerical pool has been allocated to the sister company WUC.

i. If confirmed, please confirm the allocated costs are included in the Appendix 2-N Shared Services and Corporate Cost Allocation.

---

Response:

a) Yes, costs associated with technology and the shared services clerical pool staff is charged to WUC and other affiliates.

   Costs for technology such as tablets or other devices are held within ENWIN's Information Technology cost center. That cost center is a shared service department and as such, any costs incurred in that department are allocated among ENWIN and affiliate entities based on cost drivers. In this case, the number of hardware and software applications is used as the primary cost driver.

   The clerical staff identified above is isolated into distinct cost centers: one for electricity; one for water and a shared service department. The costs captured in the water cost center, which includes the salary of the staff working on water functions along with other water specific charges, are charged to WUC. ENWIN retains the costs associated with the electricity clerical staff and associated costs. The shared service costs are allocated among ENWIN and the affiliate entities based on cost drivers within the cost allocation model.

The shared service portion of the clerical pool along with the Information Technology costs are charged to WUC and other affiliates using the cost allocation model. The results of that are contained within Appendix 2-N.

## 2 - OEB Staff - 21

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 14

Preamble:

EnWin Utilities states the following:

As discussed in Section 5.2.1(a), above, asset condition and replacement rates are informed through an ACA, which identifies [a “Flagged for Action” (“FFA”)] plan of assets expected to require attention over ten (10) years. In planning the System Renewal investments for the capital expenditure plan, ENWIN considers the FFA plan in light of observed asset failure rates and consumer rate impacts. The FFA informs ENWIN’s AMP regarding the degree of intervention required to maintain the level of reliability enjoyed by ENWIN’s customers, and also identifies additional health index information to direct future efforts to collect asset health data.

Question:

a) Did EnWin Utilities calibrate historical and forecast spending to eliminate any discontinuities in long-term spending trends that might have inadvertently been caused simply by adopting the new system?

i. If yes, please show how that calibration was done.

ii. If no, how can EnWin Utilities be confident that the new system did not inadvertently introduce unnecessary cost increases?

Response:

ENWIN did not directly adopt the Kinectrics “Flagged for Action” plan but rather used that plan to inform its own asset management plan and forward investment plans. Where the Kinectrics plan differed substantially from the ENWIN plan, the determination of forward investment rates from both plans were examined to determine the reasons for the difference and to establish the investment velocity with which ENWIN would go forward in its Distribution System Plan. This review helped to ensure that any changes in investment trends were appropriate.

## 2 - OEB Staff - 22

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 14

Exhibit 2: Rate Base, Attachment 2A, Pages 111-112

Preamble:

EnWin Utilities states the following:

ENWIN began using the Kinectrics PROSORT tool for prioritization of investment across asset categories and investment portfolios based on ENWIN's business values and their attributes. Projects are ranked based on the ratio of the risks that are mitigated and the associated benefits resulting from the cost incurred. The tool provides a means of evaluating the cost/benefit relationship of dissimilar projects so that the most cost-effective risk minimization for customers is prioritized for action. It also serves as a guideline for providing a consistent approach to decision making, and for optimizing the overall risk to the investment portfolio. This analysis will be performed annually.

In Table 40, EnWin Utilities lists the following major asset classes: Poles, Transformers, Overhead Switches, Underground Switches, Dynamic Protective Devices, Conductor, Meters, and Manholes.

For EnWin Utilities' major asset classes (per Exhibit 2: Rate Base, Attachment 2A, Page 14, Table 40: Poles; Transformers; Overhead Switches; Underground Switches; Dynamic Protective Devices; Conductor; Meters; Manholes), please answer the following questions:

Question:

a) Please provide the definition of risk that EnWin Utilities uses.

b) Please provide a sample calculation of risk that EnWin Utilities uses.

c) Please provide the definition of probability of failure that EnWin Utilities uses in its risk calculations.

d) Please provide the consequence of failure definition that EnWin Utilities uses in its risk calculations.

e) Describe how the probability of failure is calculated based on asset condition.

f) By major asset class, provide the % of assets for which EnWin Utilities has calculated a condition index, broken down by primary data source (e.g. age data only, actual condition assessment, no data, etc.).

g) By major asset class, provide the % of assets for which EnWin Utilities has derived probability of failure curves as a function of asset condition index?

h) Please describe the process for determining asset risk before and after an investment project, and describe how the mitigated risks are calculated.

i) Please describe how EnWin Utilities mitigates against introducing a risk overestimation bias via the probability of failure curves and consequence of failure assessments, e.g. if the probabilities of failure are calculated based on expected failure rates and consequence of failure is calculated based on the worst reasonable failure, wouldn't that result in a bias that overestimates risk?

j) Please provide a prioritized list of investments across all asset categories, including before and after risk assessments, project costs and mitigated risk values.

<u>Response:</u>

a) ENWIN has not formally adopted a definition of risk but considers risk to be the possibility and/or uncertainty that an unintended event will occur and affect the achievement of defined objectives. In the context of ENWIN's Distribution System Plan, risk refers to the consequences (taking into account the likelihood of occurrence) arising from:

    1. Physical asset failures within the distribution system.
    2. Operational deficiencies which may result in ENWIN's failure to meet safety, reliability (e.g. frequency and duration of outages), and sustainability performance targets; financial costs to customers or to ENWIN; or damage to ENWIN's reputation.

b) A sample calculation of a risk score is provided by considering the replacement of 3-phase padmount transformers, as shown below.

| Risks and Risk Mitigation | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Assessment of Impact of Investment to Business Values | | | | | | | | | | |
| | | Before | | | | After | | | | |
| Business Values | | Consequence | Likelihood | Score | TRS | Consequence | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | Moderate | Rare | 7 | 2.1 | Insignificant | Rare | 1 | 0.3 | SAFETY IMPROVED MOVING TO DEAD FRONT TX |
| 0.25 | Reliability | Minor | Likely | 19 | 4.75 | Minor | Rare | 3 | 0.75 | RISK OF FAILURE OF EOL TX |
| 0.25 | Financial | Moderate | Likely | 51 | 12.75 | Moderate | Rare | 7 | 1.75 | COST TO CUSTOMER >$1K |
| 0.2 | Sustainability | Minor | Possible | 13 | 2.6 | Insignificant | Rare | 1 | 0.2 | RISK OF OIL LEAK IN FAILING TX |

In this case, the consequence and likelihood scores from ENWIN's risk matrix are multiplied together to develop a risk score. This is done across the business values of Safety, Reliability, Financial and Sustainability and are weighted in accordance with pre-established weighting factors to come up with a total score. In this case, scores are calculated for the "do nothing" alternative and for the "mitigated" alternative to determine the reduction in risk rating associated with the mitigation of the risk.

c) The probability of failure that ENWIN uses in its risk determination falls within the spectrum of:
    a. Expected to occur in the next 5 years
    b. Will probably occur in the next 5 years
    c. Might occur in the next 5 years
    d. Doubtful to occur in the next 5 years
    e. May occur but only in exceptional circumstances

    Judgment is used to determine which category the probability of failure falls.

d) The consequence of failure is also defined within a spectrum of:
    a. Insignificant
    b. Minor
    c. Moderate
    d. Major
    e. Catastrophic

    Again, judgment is used to determine in which category the consequence of failure falls. ENWIN's risk matrix provides some guidance through the provision of a number of typical scenarios describing the consequence across the categories of Safety, Reliability, Financial and Sustainability.

e) The probability of failure is not calculated per se, based on asset condition. Instead, the determination of the condition of the asset informs a judgment regarding the likelihood of failure within the risk matrix.

f) The following table outlines by major asset class, whether or not a condition index has been determined and the primary data source for that determination.

| Asset | Condition Index | Data Sources for Asset Condition | % Inclusion |
|---|---|---|---|
| Poles | Yes | Tri-Annual Inspection | 100 |
| Transformers | No | Age or Inspection Condition (i.e. leaking, severe rust) | 100 |
| Overhead Switches | Yes | Inspection, Infrared | 100 |
| Underground Switches | Yes | Inspection, Infrared | 100 |
| Dynamic Protective Devices | Yes | Inspection, Infrared | 100 |
| Conductor - Overhead | No | Inspection, Infrared | By exception |
| Conductor - Underground | No | Age, some testing | 100, <1% testing |
| Meters | Yes | Testing per Measurement Canada requirements | 100, by sampling for residential meters, testing for commercial |
| Manholes | Yes | Inspection | 100 |

g) ENWIN has not derived probability of failure curves for its assets as a function of condition index.

h) See part (b) above for an explanation of the process for determining asset risk before and after an investment project, and how the mitigated risks are calculated.

i) ENWIN attempts to mitigate against a risk overestimation bias by using a panel of staff familiar with ENWIN's assets and who have experience with equipment failure to provide judgment regarding the consequence and likelihood of failure within the risk matrix. Panel members offer their opinions and differences of opinion are discussed until a consensus is achieved.

j) Please see OEB Staff 22 - Attachment 1.

## Appendix 2-OEB Staff 22 (j)

**2020 Capital Investment by Priority List**

| Project Number | 2020 Capital Investment Description | Capital Investment Category | Capital Investment $ '000 | Capital Contribution $ '000 | Pre-Mitigation Risk Score | Post - Mitigation Risk Score | Risk Reduction |
|---|---|---|---|---|---|---|---|
| 1 | O/H Customer Connections | System Access | 535 | (165) | N/A | N/A | |
| 2 | U/G Customer Connections | System Access | 525 | (335) | N/A | N/A | |
| 3 | Bridge Plaza Relocation | System Access | 1,000 | (1,000) | N/A | N/A | |
| 4 | Ambassador Bridge Twin Span | System Access | 1,000 | (1,000) | N/A | N/A | |
| 5 | Road Widening Projects (City Driven Specifics) | System Access | 1,090 | (260) | N/A | N/A | |
| 6 | Riverside Vista Project (City Driven Specifics) | System Access | 1,150 | (370) | N/A | N/A | |
| 7 | Wholesale Metering: Keith TS Feeders | System Access | 475 | (120) | N/A | N/A | |
| 8 | Meter work - new customers (enhancement) | System Access | 415 | | N/A | N/A | |
| 9 | Meter work - end of life (sustainment) | System Renewal | 35 | | N/A | N/A | |
| 10 | Meter Population Replacement / Upgrade (MIST Meters) | System Access | 515 | | N/A | N/A | |
| 11 | Reactive Replacement of Failed Equipment (U/G, O/H) | System Renewal | 180 | | N/A | N/A | |
| 12 | Reactive Replacement of Failed Cable | System Renewal | 90 | | N/A | N/A | |
| 13 | Reactive Replacement of Transformers | System Renewal | 245 | | N/A | N/A | |
| 14 | Reactive Pole Replacement | System Renewal | 50 | | N/A | N/A | |
| 15 | Reactive Pole Pulling | System Renewal | 50 | | N/A | N/A | |
| 16 | Reactive Hardware Replacement Program | System Renewal | 100 | | N/A | N/A | |
| 17 | Reactive Manhole/Vault Rehabilitation | System Renewal | 20 | | N/A | N/A | |
| 18 | Retest Smart Meters | System Renewal | 145 | | N/A | N/A | |
| 19 | Miscellaneous TS Equipment, EOL Replacement - Reactive | System Renewal | 75 | | N/A | N/A | |
| 20 | Weld / Meter Shop / Stores / Garage Misc Site - Reactive | General Plant | 75 | | N/A | N/A | |
| 21 | Pole Sustaining Program | System Renewal | 3,300 | | 31 | 7 | 24 |
| 22 | Manhole Rebuild Program | System Renewal | 150 | | 33 | 1 | 32 |
| 23 | Submersible Sustainment Program | System Renewal | 690 | | 22 | 3 | 20 |
| 24 | O/H 3-Phase Transformer Sustainment | System Renewal | 110 | | 21 | 3 | 18 |
| 25 | Removal of PMH-4 & PMH-Specials | System Renewal | 25 | | 13 | 1 | 12 |
| 26 | UG PadMount Sustaining Program | System Renewal | 255 | | 22 | 3 | 19 |
| 27 | Switching Unit Sustaining Program | System Renewal | 300 | | 56 | 4 | 52 |
| 28 | Radial Branch Backups (23M2 - Single Phase) | System Renewal | 35 | | 18 | 3 | 15 |
| 29 | Sectionalizing Load Break Switches | System Service | 150 | | 29 | 3 | 26 |
| 30 | Feeder Tie - 15M11-55M24 | System Service | 115 | | 39 | 2 | 37 |
| 31 | Automating Underground Switching Units | System Service | 550 | | 34 | 4 | 30 |
| 32 | Green Energy Plan/Walker 2 Reactors - Transfer trip pilot | System Service | 200 | | 21 | 5 | 16 |
| 33 | Radial Branch Backups (55M1) | System Service | 125 | | 18 | 3 | 15 |
| 34 | Meter Tank Replacement | System Renewal | 110 | | 14 | 1 | 13 |
| 35 | Underground Cable Sustainment (Sub Division) | System Renewal | 510 | | 44 | 4 | 41 |
| 36 | Customer SU Vault Sustainment | System Renewal | 400 | | 35 | 5 | 30 |
| 37 | Walker Road-Foster to Airport Rd | System Renewal | 750 | | 35 | 3 | 32 |
| 38 | Conductor Upgrade (23M2 LPT1) | System Service | 350 | | 19 | 1 | 18 |
| 39 | Vacuum Switch Replacements | System Renewal | 200 | | 23 | 5 | 18 |
| 40 | CPP Switch Controller Replacements | System Renewal | 100 | | 23 | 5 | 19 |
| 41 | Conductor Upgrade (55M21 LPT1) | System Service | 180 | | 10 | 2 | 8 |
| 42 | SCADA Misc Sustaining | System Renewal | 45 | | 13 | 3 | 10 |
| 43 | SCADA communications Equipment | System Service | 150 | | 13 | 3 | 10 |
| 45 | Life Cycle Upgrades | General Plant | 500 | | 24 | 2 | 22 |
| 46 | GIS Evolution and Integration | General Plant | 210 | | 46 | 7 | 39 |
| 47 | SAP Evolution | General Plant | 100 | | 46 | 7 | 39 |
| 48 | Network Infrastructure Update and Cyber Security | General Plant | 100 | | 46 | 7 | 39 |
| 49 | Customer Relationship, Billing and IVR | General Plant | 240 | | 46 | 7 | 39 |
| 50 | Strategic Enhancements and Tools | General Plant | 230 | | 46 | 7 | 39 |
| 51 | Feeder Reliability Improvement Project - Prince to Brock | System Service | 1,200 | | 46 | 2 | 45 |
| 52 | 25M7 Feeder Ring Project | System Service | 380 | | 7 | 3 | 4 |
| 53 | Site Rhodes | General Plant | 1,520 | | 48 | (2) | 50 |
| 54 | Hydro Operations Vehicles | General Plant | 1,280 | | 24 | 3 | 21 |
| 55 | Hydro Metering Vehicles | General Plant | 95 | | 24 | 3 | 21 |
| 56 | Hydro Engineering Vehicles | General Plant | 70 | | 24 | 3 | 21 |
| 57 | Site Rhodes Vehicles | General Plant | 120 | | 24 | 3 | 21 |
| 58 | Mail Room Vehicles | General Plant | 35 | | 24 | 3 | 21 |
| 59 | SCADA FCI's | System Service | 70 | | 6 | 1 | 5 |
| 60 | Operations Tools | General Plant | 85 | | 6 | 1 | 5 |
| 61 | Engineering Tools | General Plant | 5 | | 6 | 1 | 5 |
| 62 | Meter Shop Tools | General Plant | 5 | | 6 | 1 | 5 |
| 63 | Records Management System | General Plant | 330 | | 3 | 1 | 1 |
| 64 | Feeder Balancing | System Service | 50 | | 2 | 1 | 1 |
| 65 | Engineering Power Quality | System Service | 5 | | 2 | 1 | 1 |

## 2 - OEB Staff - 23

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 15

Preamble:

In explaining the other technology changes, EnWin Utilities states that:

Finally, the full implementation of CYME (power engineering software) in 2017 enabled a clearer understanding of network power flow, and identified constrained areas for remediation. It also allowed for better decision making regarding feeders that may require reinforcement.

Question:

a) Did the full implementation of CYME cause or contribute to the observed recent step increase in annual capital spending?

i. If yes, has EnWin Utilities confirmed that it is using CYME correctly, and has ENWIN calibrated the CYME metrics to ensure that its use is not creating unnecessary project triggers?

ii. If no, please explain what factors have caused the observed step change in annual capital spending.

---

Response:

a) No the full implementation of CYME did not cause the increase in annual spending.

ii) The implementation of CYME allows for System Planning to have an automatically updated GIS network that matches the real world based on GIS updates. It also provides full load model for load flow calculations for ENWIN which is an important function for the System Planning Department.

ENWIN Capital Spending varies between approximately $17M-20M yearly which includes externally driven projects. There were two exceptions in 2010/2011 due to implementation of SAP and Smart Meters and 2013/2014 due to implementation of GIS. As a result of these systems and ENWIN's equipment inspection programs, System Planning now has more visibility to asset condition and an improved ability to plan for asset replacements over the long-term.

The improved visibility into the network and the improved ability to model the network with the CYME program will allow ENWIN to confidently operate the distribution system to a higher level of utilization than in the past. This should ultimately translate to deferral of capacity upgrading that may be required in the future and the minimization of costs to customers.

## 2 - OEB Staff - 24

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 15

Preamble:

EnWin Utilities explains its pole inspection practice as below:

ENWIN re-established its pole inspection database in 2015/16 and retained a contractor to inspect all poles in its distribution system. Concurrently, ENWIN moved data from an old Microsoft Access database to the corporate ERP database which allowed data sharing between applications such as GIS and Work Manager. There were problems identified in the old database that resulted in unreliable project identification, which required additional manual effort to field-verify pole conditions. These issues were minimized through this initiative. Additionally, during a system wide inspection, ENWIN implemented a pre-emptive pole-drilling process to determine baselines for internal rot, and to apply pole preservative before internal rot takes hold rather than after it has started.

Question:

a) Please provide a table and a chart showing actual and forecast pole replacement trends broken out by annualized number of poles replaced, and total annual cost of pole replacements for the years 2009 to 2024.

Response:

a) Please see the table below:

| Year | Forecast | Actual | Forecast # Poles Replaced | Actual # Poles Replaced |
|---|---|---|---|---|
| **2009 (CGAAP)** | $ 850,000 | $ 646,001 | - | N/A |
| **2010 (CGAAP)** | $ 500,000 | $ 883,479 | - | 491 |
| **2011 (CGAAP)** | $ 1,500,000 | $ 1,350,295 | - | 1,234 |
| **2011 (MIFRS)** | $ 1,500,000 | $ 1,231,277 | - | 1,234 |
| **2012 (MIFRS)** | $ 1,500,000 | $ 1,683,987 | - | 1,062 |
| **2013 (MIFRS)** | $ 1,500,000 | $ 1,627,970 | - | 1,271 |
| **2014 (MIFRS)** | $ 1,500,000 | $ 2,844,027 | - | 830 |

| | | | | |
|---|---|---|---|---|
| **2015 (MIFRS)** | $ 2,525,000 | $ 4,017,485 | - | 765 |
| **2016 (MIFRS)** | $ 2,432,000 | $ 3,054,246 | - | 426 |
| **2017 (MIFRS)** | $ 3,000,000 | $ 2,665,883 | - | 470 |
| **2018 (MIFRS)** | $ 3,000,000 | $ 2,396,714 | - | 675 |
| **2019 (MIFRS)** | $ 3,150,000 | - | 500 | - |
| **2020 (MIFRS)** | $ 3,500,000 | - | 544 | - |
| **2021 (MIFRS)** | $ 3,500,000 | - | 544 | - |
| **2022 (MIFRS)** | $ 3,500,000 | - | 544 | - |
| **2023 (MIFRS)** | $ 3,500,000 | - | 544 | - |
| **2024 (MIFRS)** | $ 3,500,000 | - | 544 | - |

Note 1: The table above shows the total number of poles installed per year, manually extracted from ENWIN's records, including new installs, reactive 27.6kV replacements, planned 27.6kV replacements, Bell poles, and poles replaced during 4kV to 27.6kV conversions.

Note 2: The table above shows the forecasted and actual expenditure for 27.6 kV pole replacements. The numbers within this table only include planned and, when available, reactive 27.6kV pole replacements. It does not include investments in 4kV to 27.6kV conversions or Bell poles. This means that the expenditure and the number of poles are not on the same basis. ENWIN is unable to separate expenditures for new and replacement poles by cause.

## 2 - OEB Staff - 25

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 17

Preamble:

In explaining the cost-effective grid modernization, EnWin Utilities states that:

ENWIN's approach to cost-effective grid modernization planning, DER and climate change adaptation follow the principle objectives below:

1. Manage contingencies and short-term, high load requirements through:

...

b. eliminating capacity reservations and allowing loading of transformers to 100% (e.g. to facilitate the connection of EV loads);

Question:

a) Is it EnWin Utilities' understanding that good utility practice does not allow transformers to be loaded above 100% at any time?

b) Has EnWin Utilities historically not been allowing its transformers to be loaded to 100%? Please explain the technical basis of this practice.

c) Has this historical practice required EnWin Utilities to implement capital additions to avoid loading transformers to 100% (or near 100%) of nameplate on peak? Please list any such investments that have been made since 2009, or that are planned for the forecast period.

---

Response:

a) ENWIN follows a design practice of allocating 4kVA for an average house, in a typical residential area, which is supplied by a 120/240V 100kVA transformer. The result is 80 kVA loading and a design loading practice of 80% is followed by ENWIN. During peak times, in certain areas, transformers can and do have loading that is above 100%. Transformer loading above 100% is investigated but typically action occurs when a transformer is loaded above 120% on a consistent and reoccurring basis.

b) As mentioned above, the Engineering department plans for 80% loading and allows loading to reach 100% without concern over the life of the asset. All transformers that are loaded above 100% in any given month are part of the monthly transformer overload report, however, focus is on the 120% or higher loaded transformers.

c) As stated above, there is no practice to not allow transformers to be loaded to 100% (or near 100%) and as such there has been no capital spending related to this.

## 2 - OEB Staff - 26

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 22

Preamble:

EnWin Utilities states the following:

The assets will be replaced in cost-effective and timely manner. The main considerations driving this project include the following:

...

2. Some of the switches rust due to salt spray, needing continuous painting and dry ice cleaning to maintain reliability.

Question:

a) How will the replacement units be protected from being affected by this same issue?

---

Response:

The replacement units are specified and purchased with stainless steel enclosures that shall minimize the possibility of being affected by this same issue. Some units are dead front which reduces the risk of flashover due to salt contamination.

## 2 - OEB Staff - 27

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 45

Preamble:

EnWin Utilities explained its worst feeder analysis as follows:

ENWIN analyzes worst performing feeders on a three-year average to give an accurate representation of the worst performing feeder ranking. This ensures that unusual feeder activity in one year will not skew results. Just like the power quality complaints section, there is no specific ENWIN internal target for worst performing feeders, but the obvious goal is to target repeat worst performing feeders with projects that will improve their performance.

**Table 9 Worst Performing Feeders**

| Year | Worst Performing Feeders In Order |
|---|---|
| 2012-2014 | 55M25 24M5 56M8 25M7 55M22 56M7 56M1 24M4 55M23 55M24 |
| 2013-2015 | 25M7 55M25 56M8 55M23 24M5 56M7 55M22 24M4 56M1 15M7 |
| 2014-2016 | 56M8 25M7 55M25 55M23 56M1 56M7 24M5 24M4 24M3 55M22 |
| 2015-2017 | 56M8 25M7 55M22 55M23 56M1 55M25 56M2 56M7 56M5 23M2 |

Question:

a) What is the population for the feeder analysis? Does EnWin Utilities include all its feeders in the analysis?

b) Please elaborate on the statement of “there is no specific ENWIN internal target for worst performing feeder” and explain why an internal target is not needed.

c) Please confirm that there will always be a worst performing feeder, even if all feeders achieve an objectively determined acceptable performance level.

d) What are the internal processes and procedures in the EnWin Utilities’ Worst Performing Feeder program to ensure that feeders that achieve acceptable performance are not inadvertently targeted for capital investments simply because their performance is determined to be the worst in the EnWin Utilities’ system?

Please explain why the feeder 55M22 has moved from 5th worst, to 7th worst, to 10th worst, to 3rd worst over the period shown in Table 9.

Response:

a) ENWIN does use all of its feeders in its analysis of worst performing feeders.

b) ENWIN does not have a "target" for worst performing feeders. ENWIN uses the worst performing feeder analysis to inform its judgments regarding projects to bring forward for consideration and in determining the relative priority ranking of projects using its PROSORT tool.

c) ENWIN confirms that there will always be a "worst performing feeder" as this is an exercise to rank feeder performance and not to set a target or threshold for investment.

d) ENWIN does not drive investment on the sole basis of a feeder's performance or ranking on the "worst performing" list. Investments are driven through separate considerations and the "worst performing" list is a tool to inform judgment about the relative ranking of projects in the PROSORT tool.

   The shift in ranking for the 55M22 is a function of the performance of the feeder itself as well as the other feeders on the list. As noted in the submission, the ranking is an average ranking over a 3-year period. There have been no specific measures taken over this period whose aim it is to improve the performance of the 55M22. The performance of a feeder is dependent upon not only the strength and resiliency of the feeder but on what happens to the feeder in any particular year (i.e. storms, station outages, vehicular accidents, etc.). As well, from time to time feeders may support the load and customers from other connected feeders while work is conducted on the adjacent feeder. Should an outage occur during this time, the number of customer hours of outage can be increased greatly and adversely influence the feeder performance and ranking. Given the variables that could occur and affect the performance of the 55M2 feeder, over a 6-year period needed to cover the ranking shifts mentioned, it is not possible to definitively provide a rationale for the change in performance ranking.

## 2 - OEB Staff - 28

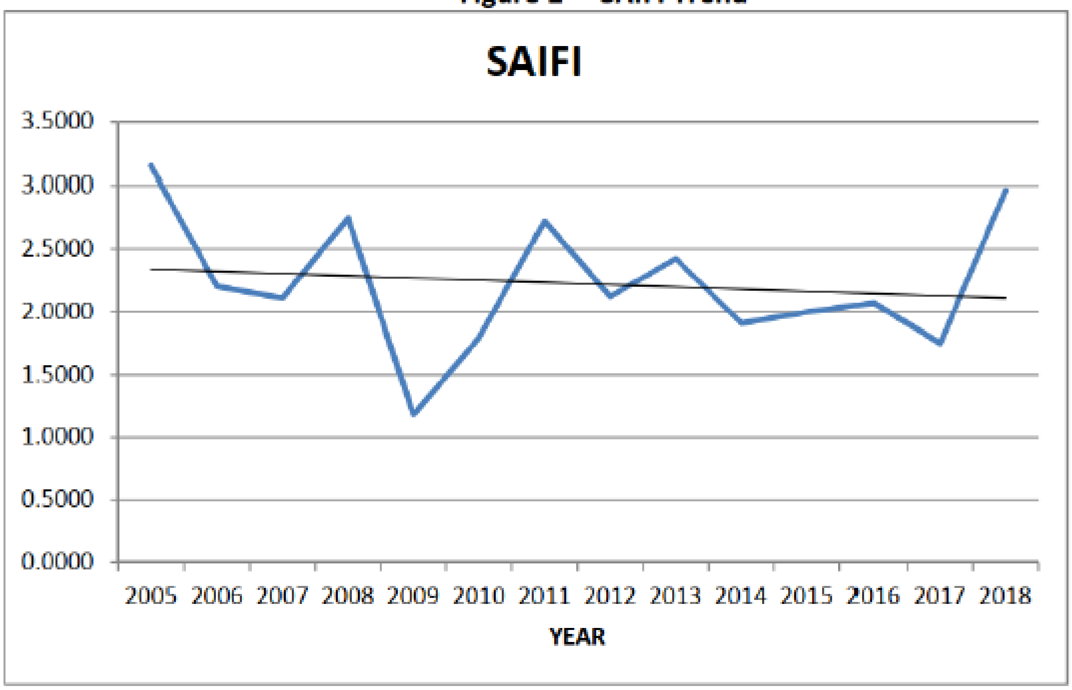
Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 54

Preamble:

EnWin Utilities provides one of the reliability performance for SAIFI trend in Figure 2 below:

**Figure 2 SAIFI Trend**




EnWin Utilities states that "Long-term trending data for SAIFI since 2005 shows a clear downward trend".

Question:

a) Please confirm that EnWin Utilities' favourable historical outage frequency performance trend indicates that historical levels of System Renewal capital spending have been adequate to maintain EnWin Utilities' system assets in a condition that has supported increasingly good reliability performance.

Response:

Not confirmed. ENWIN's SAIFI trend is clearly downward but the slope of the line is quite shallow indicating a slight improvement in the frequency of outages. ENWIN's view is that ENWIN has maintained its frequency of outages despite climate change which brings increasingly frequent and intense storms.

## 2 - OEB Staff - 29

Reference:

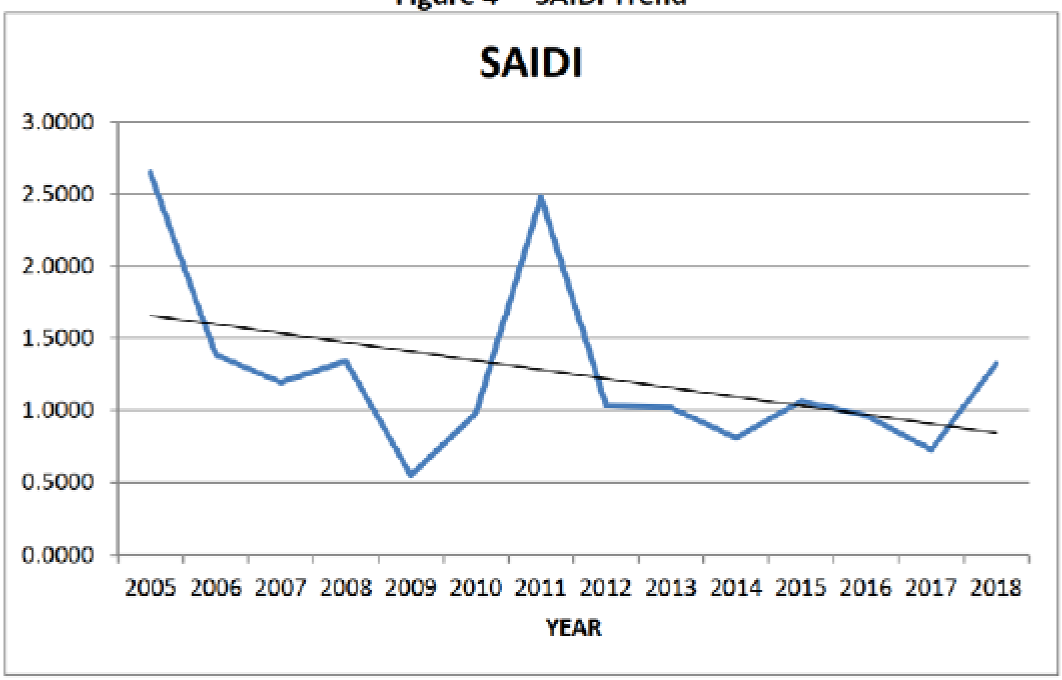
Exhibit 2: Rate Base, Attachment 2A, Page 56

Exhibit 2: Rate Base, Attachment 2A, Page 12

Preamble:

EnWin Utilities provides one of the reliability performance for SAIDI trend in Figure 4:

**Figure 4 SAIDI Trend**




In reference to its O&M spending resulting from automation, EnWin Utilities states:

The continuation of the grid modernization … is expected to automate operations and minimize truck dispatches, while minimizing outages and reducing restoration times. To date, ENWIN's implementation of such automation has facilitated workforce reduction without compromising reliability.

Question:

a) Has EnWin Utilities' system automation program contributed to this outage duration performance improvement?

b) What proportion of EnWin Utilities' system automation capital investment program will have been completed by the end of 2019?

c) Please provide the total future spending required to complete the system automation capital investment program by year over the forecast period.

---

Response:

a) Yes, ENWIN's system automation program has positively contributed to the outage duration shown in the SAIDI graph. The goal of the feeder sectionalizing project was to split the feeder into three sections or more by using a remote operable device. Each of these sections is then connected to a different feeder's section (that was also split in three) by a remote operable device. By doing this any single contingency will only impact one third of a feeder (or less). Therefore, theoretically, the automation program helped to save two thirds of the customer outage hours for each feeder outage.

b) ENWIN's overall system automation plan consists of the following 6 categories, with their percent completion listed by the end of 2019. Further details are provided for each category in the table below.

| Category | % Complete by end of 2019 |
|---|---|
| 1) Feeder Sectionalizing Load Break Switches | 98 |
| 2) Live front underground switches automation | 88 |
| 3) SCADA-FCI installation | 100 |
| 4) Communication Infrastructure | 0 – Postponed |
| 5) SCADA Distribution Management System | 0 – Start in 2021 |
| 6) Specific identified projects – Pilot | 0 – Start in 2020 |

(1) Feeder Sectionalizing Load Break Switches is at the end of the program with 98% of the intended (note that not all feeders were intended for operation in thirds) switches complete. All of the installed remote operable switches and protective devices are operating as intended.
(2) The Underground switches automation program has three phases, with phase I having 88% of intended (not all switches were intended for automation) units complete. Phase I identified switches that required remote operability for improved system reliability. Phase II and III are meant to extend the asset life and postpone

large capital investment as much as possible. Phase II refurbishes the live front unit to extend its life. Phase III is the replacement of all live front PMH units with dead front units at the end of their life.

(3) The SCADA FCI installation will be 100% complete. The project is meant to identify faults along the circuit by having them strategically placed to help the crews identify the nearest possible location of the fault instead of having to spend significant time patrolling large feeders to identify where the fault has occurred. By pinpointing the likely location of the fault, Operators are able to remotely sectionalize the feeders and restore power to unfaulted sections. As well, the SCADA FCI units are intended to be a key element to a future automated grid where the central control system, rather than a human operator, is able to identify fault location, isolate and restore power to unfaulted sections.

(4) The Communication infrastructure project has been postponed until the next budget cycle. ENWIN performed a detailed communications system study with the intention to develop a communications infrastructure for the growing field device communication requirements. However, due to the large capital investment and the decrease in cellular data plans this project was postponed and will be re-evaluated in the next budget cycle.

(5) The Distribution Management System is proposed to begin in 2021.

(6) The pilot automation project for the 25M7 ring feeder is proposed to begin in 2020.

c) The total future spending to complete the system automation is shown yearly in $000s:

| Category | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| 1) Feeder Sectionalizing Load Break Switches | 385 | 77 | - | - | - | - |
| 2) Live front underground switches automation | 560 | 840 | - | - | - | - |
| 3) SCADA-FCI installation | 295 | 295 | 115 | 115 | 115 | 115 |
| 4) Communication Infrastructure | 300 | 300 | 150 | - | - | - |
| 5) SCADA Distribution Management System | - | - | 750 | 250 | 200 | 200 |
| 6) Other identified projects – Pilot | - | 380 | 550 | 438 | 585 | 550 |

## 2 - OEB Staff - 30

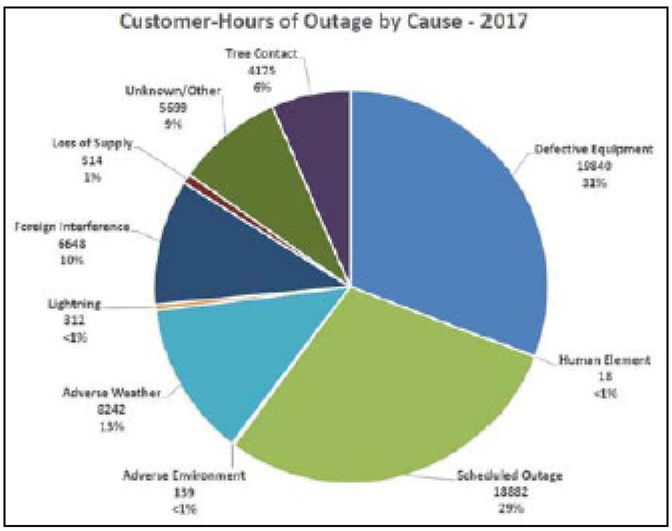
Reference:

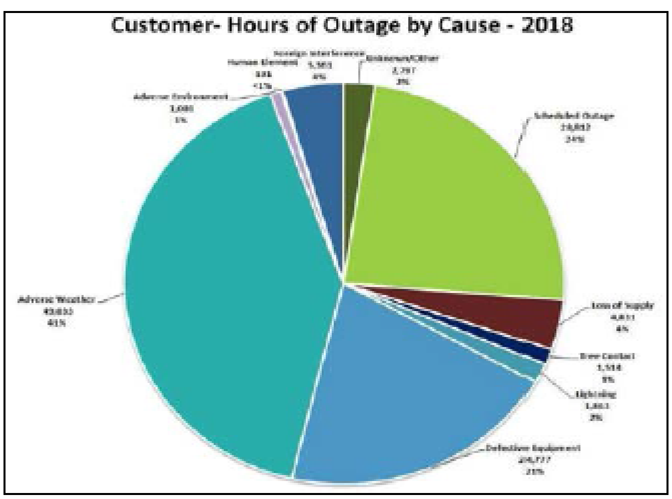
Exhibit 2: Rate Base, Attachment 2A, Page 46

Exhibit 2: Rate Base, Attachment 2A, Page 60

Preamble:

At the above noted reference, EnWin Utilities provides the outages by cause for 2017 and 2018 in the figures below:



Customer-Hours of Outage caused by tree contacts decreased from 4,175 hours (6% of total outage hours) to 1,514 hours (1% of total outage hours) from 2017 to 2018, respectively. In the Worst Performing Feeder section of this DSP. EnWin Utilities explains:

Now that ENWIN's tree trimming clearance has increased to 10 feet, the performance of these feeders should also improve over time.

Question:

a) Does EnWin Utilities attribute the significant reduction in customer outage hours caused by tree contacts between 2017 and 2018 to implementation of the new tree trimming clearance?

i. If not, please explain how this reduction was achieved.

---

Response:

a) The reduction in customer outage hours caused by tree contacts can be partially explained by the new tree trimming clearances but it is difficult to exactly correlate/quantify. There were also better processes put in place, including the use of GIS and tracking tools that allowed ENWIN to inspect and better monitor the work and performance of its tree trimming contractor. ENWIN staff has intensified the use of the new outage management system, with AMI and SCADA integration, which allow staff to identify fault locations faster and not rely only on customer calls before dispatching restoration crews, consequently also reducing the outage hours caused by tree contacts.

## 2 - OEB Staff - 31

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 61

Preamble:

EnWin Utilities states the following:

Customers receive notification of Scheduled Outages so they are generally less impactful than unplanned outages. Nevertheless, the number of customer-hours of outage due to planned work is a significant contributor to ENWIN's reliability statistics. The customer-hours of Scheduled Outage interruption was reduced in 2017 to 18,882 or a 23% reduction. This was accomplished in part due to a mild storm season and by combining work into single outages, building temporary supplies to minimize the number of customers involved in an outage and working live where it can be done safely.

Question:

a) Please confirm that EnWin Utilities does not consider outages caused by Scheduled Outages when determining which facilities are performing poorly and require increased System Renewal spending.

   i. If not confirmed, please explain how EnWin Utilities correlates Scheduled Outage results with reliability performance.

---

Response:

a) ENWIN planned outages are included in the reliability performance indicators as per OEB rules; however, when prioritizing and determining which facilities are performing poorly, these outages are separated and treated differently. There are programs aiming to increase system flexibility by providing alternative supplies to facilitate outages planning and these planned outages statistics are used to better tailor this type of investment.

## 2 - OEB Staff - 32

Reference:

Exhibit 2: Rate Base, Attachment 2A, Pages 84-85

Preamble:

EnWin Utilities states the following:

ENWIN's financial performance objective is to maximize the value it obtains from its assets. …

ENWIN's operational performance objective is to ensure that assets are able to deliver the value expected by customers and shareholders at optimum cost. …

ENWIN's risk objective is to minimize probability of occurrence and the impact of asset related negative outcomes. …

ENWIN's sustainability objective is to minimize the economic and environmental footprint of its operations commensurate with good utility practise. …

… ENWIN's senior management has consolidated these business values into four categories, and developed a weighting for each category. …

1. Safety includes the safety of both the public and ENWIN's employees as well as risk of damage to property. …

2. Reliability includes both the reliability of the distribution system as well as the resiliency of the system itself, and ENWIN's ability to restore it after an upset. …

3. Financial Risk includes consideration not only for costs borne by ENWIN, but also the risk that a negative outcome will result in ENWIN's customers incurring costs. …

4. Sustainability is the final category of ENWIN's business values. This category encompasses regulatory compliance, environmental stewardship, conservation, and reputational risk minimization. …

The Table 25 below shows the weightings for ENWIN's business values.

Table 25 Business Values and Weighting

| Category | Weighting |
|---|---|
| Safety (including public and employee safety and property risk minimization) | 30% |
| Reliability (including sufficiency, contingency and risk minimization) | 25% |
| Financial Risk (including customer and utility costs risk minimization and Capital and O&M efficiency) | 25% |
| Sustainability (including regulatory compliance, environmental stewardship, conservation, and reputational risk minimization) | 20% |

Question:

a) For EnWin Utilities' financial, operational, risk, and sustainability objectives, please define in quantitative terms how the objective is measured.

b) How do EnWin Utilities' financial, operational, risk, and sustainability objectives relate to its Business Values, including a discussion of precedence?

c) What is the relative ranking of financial, operational, risk, and sustainability objectives?

d) Are the financial, operational, risk, and sustainability objectives (and their ranking, if applicable) informed by the customer preferences expressed in Exhibit 2: Rate Base, Attachment 2A, Appendix B, Page 9? In particular, do the objectives account for the fact that EnWin Utilities' customers' top priority is low costs?

e) Please confirm the following ranking of Business Values from most to least important.

1. Safety
2. Reliability
3. Financial Risk
4. Sustainability

f) Please show how the different business value weightings have been calculated, quantitatively.

g) Please define cost risk minimization (Table 25) and how it is calculated in quantitative terms.

h) Please define Capital and O&M efficiency (Table 25) and how it is calculated in quantitative terms.

i) Please explain why Ratepayer Cost Minimization has not been identified as an EnWin Utilities' business value.

j) Does EnWin Utilities' asset management decision-making process consider ratepayer cost impacts?

i. If no, please explain why not.

ii. If yes, show explicitly how consideration of ratepayer cost impacts is integrated into the asset management decision-making process.

---

Response:

a) ENWIN Utilities' financial, operational, risk, and sustainability objectives are not defined in quantitative terms and are not measured directly. However, these objectives are translated into Safety, Reliability, Financial Risk and Sustainability goals for which hard targets have been established, as follows.
    a. ENWIN has a Safety goal of having lost time days being less than the previous 5-year rolling average.
    b. ENWIN has a Reliability goal of having outages affecting 1,000 customers or more for 5 minutes or more be less than 5% of its outage.
    c. ENWIN has a number of Financial Risk goals including having expenditures not exceed budgeted amounts, ensuring capital investment is at least 80% of that budgeted, maintaining a reasonable current ratio, meeting net income targets and reducing inventory levels to prescribed amounts.
    d. ENWIN had a Sustainability goal of meeting its CDM target, meeting all aspects of regulatory compliance including first call resolution and calls answered on-time, 70% of the time.
b) Per table 25 on page 85 of the Distribution System Plan, ENWIN Utilities' financial, operational, risk, and sustainability objectives relate to its Business Values as follows.
    a. Safety includes public and employee safety and property risk minimization and addresses operational objectives.
    b. Reliability includes sufficiency, contingency and risk minimization and addresses both operational and risk objectives.
    c. Financial Risk includes customer and utility cost risk minimization and Capital and O&M efficiency which addresses financial and risk objectives.

d. Sustainability includes regulatory compliance, environmental stewardship, conservation, and reputational risk minimization.

c) ENWIN does not rank its financial, operational, risk, and sustainability objectives but instead ranks its Business Values into which those objectives are reflected. The rankings are as per Table 25 in the DSP, as follows:

| Category | Weighting |
|---|---|
| Safety | 30% |
| Reliability | 25% |
| Financial Risk | 25% |
| Sustainability | 20% |

d) The ranking of the business values are informed by the customer survey where customers rank cost as their top priority. At one time, Reliability was ranked at 30% with Financial Risk, the value which reflects costs to customers, ranked at 20%. In light of customer's priorities, this was increased to 25% and Reliability decreased to 25%.

e) The rankings are confirmed per section (c), above.

f) The business value rankings were not calculated on a quantitative basis but were rather a judgment determined by the Executives of the company.

g) ENWIN does not have a definition of "cost risk minimization" and it is not calculated quantitatively however, what is meant by the term is the avoidance of or minimization of costs for both the utility and for the customer. This includes not only direct customer costs through rates but also indirect customer costs due to loss resulting from interruption of electrical service.

h) ENWIN does not define "Capital and O&M Efficiency" nor calculate it quantitatively however what is meant by the term is the avoidance or minimization of both capital and operating costs through the efficient planning and execution of capital and operating programs. An example would be the tendering of transformer supply to ensure lowest costs or the placement of transformers at the head-ends of alleys so that they are more easily maintained than if they were installed mid-block in a customer's back yard.

i) "Ratepayer Cost Minimization" has been identified as a component of ENWIN's Financial Risk business value. That business value specifically deals with customer cost risk minimization and utility cost risk minimization, which in turn reflects in rates to the customer.

j) ENWIN's decision making process does include consideration of ratepayer cost impacts. ENWIN is always aware that any investment, whether capital or operating, must be borne by the ratepayers and must show a benefit to ratepayers for making the investment. This is reflected in ENWIN's risk matrix under the Safety business value where property damage to customer's property is included for consideration. Additionally, within the business value of Financial Risk, customer costs and utility costs, which become customer costs, are specifically included in the analysis.

## 2 - OEB Staff - 33

Reference:

Exhibit 2: Exhibit 2: Rate Base, Attachment 2A, Page 87

Preamble:

In reference to reliability strategies, EnWin Utilities states that:

Reliability Strategies:

...

3. ENWIN will utilize a program of maintenance for its assets to ensure their serviceable life is maximized.

Question:

a) How do serviceable life, asset life, estimated service life, and end of life (measured in years) compare as metrics for describing an asset? Please provide specific quantified examples of how these terms each apply to transformers and wood poles.

---

Response:

a) These terms have the same meaning and are interchangeable.

## 2 - OEB Staff - 34

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 87

Preamble:

In reference to reliability strategies, EnWin Utilities states that:

5. ENWIN will improve the reliability and economic operation of its network through the improvement of its SCADA system.

Question:

a) Is EnWin Utilities able to quantitatively calculate the improvement in reliability that will result from the improvement of the SCADA system?

i) If yes, what is the calculated improvement in reliability?

ii) What is the cost of achieving that reliability improvement?

b) Is improving reliability capped at a specific cost / reliability improvement level, either for financial reasons or for customer preference reasons? If so, please provide the specific cost/reliability level.

---

Response:

a) i) The strategies listed in this section of the DSP are high level strategies and do not refer to a specific investment. ENWIN is not able to calculate an improvement in system reliability associated with an improvement in the SCADA system nor any particular investment. The reliability of a distribution system is a function of many factors including what stressors (i.e. storms, vehicle accidents, squirrel contacts, tree contacts, etc.) to which the system is subject over a course of time. The distribution system is a dynamic system which changes over time as feeders are reconfigured and the system is expanded to serve new customers. The SCADA system however provides visibility into the operations and upsets that happen to the distribution system and as such, will always improve the reliability of the system. Knowing where to send staff to address a problem also saves time and effort and results in a more economic operation of the system along with a lessening of the time of outage for customers.

ii) The planned investment in the test year for SCADA Improvements is $265,000.

b) Improvements to reliability are not calculated in terms of a cost per expected level of improvement and consequently a cap on this basis has not been determined.

## 2 - OEB Staff - 35

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 87

Preamble:

EnWin Utilities explains its sufficiency strategy as follows:

ENWIN will maintain a capacity reserve of an average of 1 to 2 MW per feeder. When this reserve is compromised because of load additions, ENWIN will make adjustments to its distribution system to maintain the capacity reserve or make plans to build for more capacity.

Question:

a) Is the capacity reserve calculated assuming peak feeder load, peak feeder load while providing backup to an adjacent feeder, or using a different basis?

i. How many hours would the feeder be exposed to this situation in an average year?

ii. What risks are associated with exceeding this limit for several hours each year?

b) What is the analytic basis for EnWin Utilities' decision to maintain a capacity reserve average of 1 to 2 MW per feeder?

c) Does this strategy change in areas of negative load growth, flat load growth, and positive load growth? Please quantify the change in strategy based on load growth projections.

Response:

a) ENWIN's reserve level is calculated based on peak feeder load. However, ENWIN's load is highly sensitive to temperature and the duration of heat waves, as this typically results in the observed peak load. ENWIN monitors the individual feeder peak load for three consecutive years to have a better reflection of the true peak feeder loading.
   (i) The feeder peak generally lasts a few hours.
   (ii) The key risk would be if the feeder peak goes beyond the system design limit. The immediate repercussion would be the inability to support an adjacent feeder in a contingency. This may lead to long outage times for the adjacent feeder.

b) There is no specific analytic basis for the 1 to 2 MW reserve capacity per feeder. The standard is based on judgment related to the time related for project approvals, budget cycle approvals and therefore the overall processing time to ensure ENWIN has capacity for its customers when they require it.

c) ENWIN maintains the same planning concepts throughout the entire system regardless of load growth profile. Where growth is stagnant or declining, no capital investment is needed in the short term for capacity assurance. Where a feeder has reached its capacity limit, ENWIN's first choice is to move feeder segments to supplies from other feeders, thereby maximizing the use of the existing system and avoiding a capital investment. The connection of distributed generators to the grid, with their fault current capacity allocation to a specific feeder and station, is reducing the viability of this relatively low cost solution.

## 2 - OEB Staff - 36

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 88

Preamble:

EnWin Utilities explains its risk minimization strategies as follows:

3. Risk assessment will be performed informally through asset inspections where assets at risk are identified and brought forward for mitigation.

Question:

a) Please explain what "risk assessment will be performed informally through asset inspections" means.

b) Please explain the inputs and frequency of the asset inspection.

c) Please explain the outputs from a typical asset inspection.

d) Please explain how risk is calculated based on a typical asset inspection.

e) When assets at risk are brought forward for mitigation, how many mitigation alternatives are typically considered and how is the ultimate mitigation selected? Please use an example for the illustration.

---

Response:

a) This statement indicates that when inspectors are assigned to routine asset inspections they will additionally assess the impending risk of that asset (in regards to its health or any other conditions that may present a risk) during that inspection. If there is cause for immediate concern, they will create a follow-up “notification” in the SAP ERP system which will initiate a follow-up and will notify their supervisor. If there are conditions that are not an emergency in nature, but require an expedited replacement schedule for that asset, they will communicate this to Engineering. Examples include discovery that a building is under construction that is too close to or underneath the pole line, soil that is piled up around the pole base that is over top of the area of butt treatment, trees being planted underneath the pole line, a dead tree within fall distance of the pole line, etc.

b) & c) The inputs, frequency, and outputs of asset inspections are detailed below:

| Asset | Inspection Frequency | Inspection Inputs | Inspection Outputs |
|---|---|---|---|
| **Pad-mounted Transformers** | 3 years | - Visual condition inspection of cables, elbows/bushings, terminations, enclosure, tank, evidence of oil leaks | - Health index<br>- Verification of safe condition<br>- Follow-ups for any immediate repairs |
| **Vault Transformer** | Annually | -As above | -As above |
| **Submersible Transformer** | 3 years | - Visual inspection of connections, tank, lock, grate, elbows & bushings, aqua seal, paint, secondary bars, primary cable | - Health index<br>- Verification of safe condition |
| **OH Switches/Protective Devices** | 3 years | - IR thermoscan<br>- Switch operation | -Trouble calls for repairs (after operating)<br>-Work orders for repairs when hotspots found during IR thermoscan |
| **Pad-mounted Switchgear** | 3 years | - IR Scan<br>- Visual condition inspection of enclosure, cable connections, debris, lock condition, tank, grading, lid, insulators, switch, baffle board, Uni-ruptors & mechanism | - Health index<br>- Verification of safe condition<br>- Follow-ups for any immediate repairs |
| **Vault Switchgear** | Annually | - Same as pad-mounted switch gear inspection but additionally evaluate vault condition | - Health index<br>- Verification of safe condition<br>- Follow-ups for any immediate repairs |
| **OH Conductors** | 3 years | - IR thermoscan<br>- Visual patrol inspection | - Verification of safe condition<br>- Follow-ups for any |

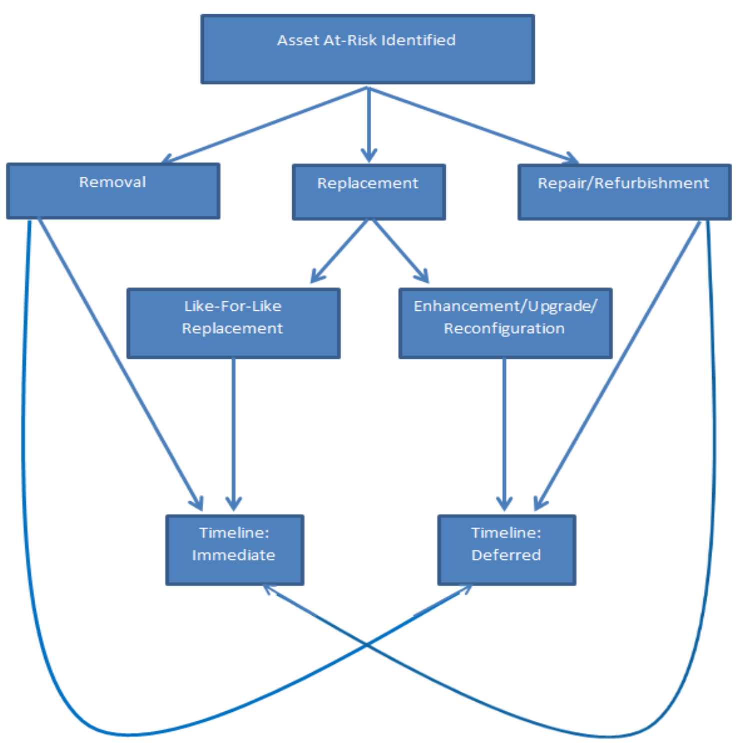
| | | | |
|---|---|---|---|
| | | | immediate repairs |
| **Poles** | 3 years | - Visual inspections for rot/deterioration<br>- Ground wire resistance & current measurements<br>- Hammer test<br>-Drill inspections – at year 20 or 30 depending on preservative treatment | - Health index<br>- Verification of safe condition<br>- Follow-ups for any immediate repairs |
| **Transformer Station (Outdoor Open)** | Monthly | - Safety/security checks<br>- Dissolved gas analysis/oil screen<br>- Transformer ratio tests<br>- Secondary containment<br>- Relay testing | - Verification of safe condition<br>- Repairs made if required |
| **Manholes** | 5 years (or less per the recommendation of the engineer) for structural integrity | Visual inspection of structural integrity by civil engineer | Manhole report, prioritized manhole sustainment schedule |
| **Handholes** | Annually | Inspection of structural integrity, insulation, cabling | On-site repairs during inspection, follow up notification for return-to-site repairs |

d) Typically, asset inspections are used to inform an Asset Health Assessment which is used to flag units for replacements with varying timelines depending on the severity of the deterioration. The health index itself inherently provides an evaluation of the likelihood of failure based on the health index calculation. From these results, a list of potential projects is compiled. These projects are then evaluated during a 'Risk Review Activity' ('RRA') and using Kinectrics' PROSORT software. This RRA is undertaken to identify asset-related risks, assess their likelihood, consequence, and detectability, and describe the operational controls that are in place to mitigate the risk to an acceptable level.

Using the software, consequences and likelihood of asset failure are combined to estimate risk. Total risk scores for a project are calculated for two scenarios: one being if the project is not undertaken, and one for if the project is implemented and completed. The total cost of the project is then divided by the reduction in risk score that would occur if the project was undertaken - this results in the "Risk Reduction Factor". Other factors and side benefits that would provide value to customers, independent of risk reductions, are also assigned scores within a "Benefit Matrix".

e) When assets at risk are brought forward for mitigation, the number of alternatives considered is dependent on the asset type, current and future configuration of the asset, location of the asset, and many other inputs. Additionally, the investment path chosen is determined through consideration of the technical feasibility, reliability advantage, and economic advantage of each alternative.

Generally, mitigation alternatives follow a similar path as shown in the below figure:



For example, when considering the sustainment of overhead or underground cables, the costs/benefits of cable injection versus cable replacement are considered. As another example, PMH switching units have three basic paths: refurbishment, replacement, and enhancement. The cost/benefit of each situation is weighed and decided upon during the Risk Review Activity.

## 2 - OEB Staff - 37

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 88

Exhibit 2: Rate Base, Attachment 2A, Page 111-112

Preamble:

EnWin Utilities explains its Capital Efficiency Strategies as follows:

1. ENWIN will consider the full life-cycle cost, including retirement and recycling costs, for the elements that make up its distribution system.

2. ENWIN will design its assets with due regard to their efficiency of operation and maintenance over the lifetime of the assets.

3. ENWIN will maintain its assets in order to maximize their useful service life.

In Table 40, EnWin Utilities lists the following major asset classes: Poles, Transformers, Overhead Switches, Underground Switches, Dynamic Protective Devices, Conductor, Meters, and Manholes.

Question:

a) Please provide examples of quantified analyses applying each of the three referenced strategies for each of EnWin Utilities' major asset classes.

---

Response:

a) The following are examples, for major equipment classes, where ENWIN considers full life cycle costing, efficiency of operations and maintenance to increase useful life.

- Poles: ENWIN chooses pole material (mainly wood or concrete) taking into account life-cycle costs and treats its wood poles with boron rods mid-life in order to extend the useful life of the pole.
- Transformers: ENWIN's designs require placement of transformers at locations that minimize maintenance costs by providing easier access (alley ends, for example). ENWIN implemented a pilot project to explore "Cold Spray" technology to perform repairs of

transformer and switchgear enclosures, and to provide an effective corrosion protection of the repaired areas to extend the asset life. Preliminary analysis of the field repairs shows that the maintenance cost can be substantially reduced by the application of this technology, as it helps extend the equipment maintenance intervals.

- Underground switches: ENWIN now purchases switches with stainless steel enclosures to maximize service life. For older switchgear, ENWIN hires a third party to dry ice blast clean its switchgear. Thermographic inspections are performed before and after the cleaning to identify any hot spots or tracking, and to ensure that they have been adequately remediated.
- Overhead Switches and Dynamic Protective Devices: ENWIN inspects and operates its overhead reclosers and switches on an annual basis to ensure they are readily operable. Where units are operated during the course of the year, they will not be inspected again. This also tests the functionality of the SCADA and communication systems at the same time. If the inspection indicates that maintenance is required, such maintenance will be scheduled.
- Conductor: Where a conductor is replaced, ENWIN removes the old conductor from service, where possible, and then collects and recycles the old conductor.
- Meters: ENWIN tests meters at the end of their seal life with the intention to extend the seal life of the meters either through sampling or direct testing and re-sealing of the meters, as allowed by Measurement Canada. Where meters are at end-of-life, ENWIN sends the meters to a vendor who recycles the meter components.
- Manholes: ENWIN has its manholes inspected by third-party professional engineers, who indicate any areas that require remediation, which are then engineered and queued for execution, unless the situation is urgent.

## 2 - OEB Staff - 38

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 89

Preamble:

EnWin Utilities states the following:

Each supply station and feeder is reviewed for deficiency and opportunity; as is the interconnected distribution system. The review is intended to:

1. identify assets at risk because of their health assessment or location;

Question:

a) Please describe how risk is calculated based on health assessment.

b) Please describe how risk is calculated based on location.

---

Response:

a) ENWIN does not do a calculation of risk based on health assessment however, where an asset has a poor health assessment, then the likelihood of failure is judged to be more likely than an asset with a good health assessment. In that case, a project may be brought forward for assessment within ENWIN's risk matrix and a higher risk score assigned on the basis of judgment.

b) ENWIN does not do a calculation of risk based on location however, the location of an asset on the distribution system may influence the consequence of a failure within ENWIN's risk matrix. For example, the failure of the first pole outside a transformer station will result in the loss of the feeder, a higher consequence, than the last pole in the feeder, which may not have a significant consequence at all. Assets with higher consequences of failure will have a higher risk score assigned on the basis of judgment.

## 2 - OEB Staff - 39

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 91

Preamble:

EnWin Utilities explains the risk review activity as below:

Unlike "Asset Knowledge Collection" which seeks to gather information about the health attributes of particular assets, the "Risk Review" looks at assets and the distribution system in the context of their environment and the reliance which is made upon the asset(s). Risk Review is an activity whose purpose is to identify asset-related risks, assess their likelihood, consequence and detectability, and describe the operational controls that are in place to mitigate the risk to an acceptable level. The Risk Review informs the Asset Planning Activity. The output of the Risk Review is a listing of assets that have been identified as candidates for additional risk mitigation controls.

Question:

a) What does "detectability" mean as that term is used in the reference?

b) Please explain what impact detectability has on the risk calculation. Specifically, how does detectability influence the determination of probability and consequence of failure?

---

Response:

a) "Detectability" refers to the ability of the utility to detect or determine the condition of the asset and is a means of mitigating risk. For example, if a utility did not inspect their poles for condition, this would increase the uncertainty that an unintended event (i.e. a pole failure) will occur and adversely affect the supply of electricity to customers. In this example, a mitigation might be to begin a program to inspect the assets and determine their health condition.

b) "Detectability" does not affect the probability or consequence of failure. If appropriate actions are taken after it has been detected that an asset is at increased likelihood of failure then that likelihood of failure may be reduced.

## 2 - OEB Staff - 40

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 91

Preamble:

EnWin Utilities explains the Asset Knowledge Collection Activity as below:

This is the activity of collecting the data that describes the health attributes of the assets. This data is obtained through asset health inspection programs, performance reviews and experiential inputs. The outputs of the Asset Knowledge Collection Activity are reports describing the ability of the assets to perform or continue to perform their designed functions. These reports inform the "Asset Planning Activity"...

Question:

a) How are experiential inputs, performance review and health inspections compared on a quantitative basis?

b) If not comparable on a quantitative basis, what is the basis of comparison?

c) Please use an example to explain the activity.

Response:

a) Experiential inputs, performance review and health inspections are not compared on a quantitative basis however they do inform the judgment regarding the likelihood of an asset to fail in service.

b) As noted in (a) above, these inputs are not compared.

c) As an example, ENWIN may receive experiential input from field staff that they have observed a number of underground cable failures in a certain neighbourhood. This may prompt a review of interruptions in the area over the last 5 years which may support that there have been cable failures and that the cable may be nearing end of life. This may be compared to the cable age and type to determine if that cable is at typical end of life. As well, testing of the cable may be undertaken to quantify the health of the cable. These things, taken together, will inform the judgment as to the likelihood of further cable failures and the need to replace or inject the cable.

## 2 - OEB Staff - 41

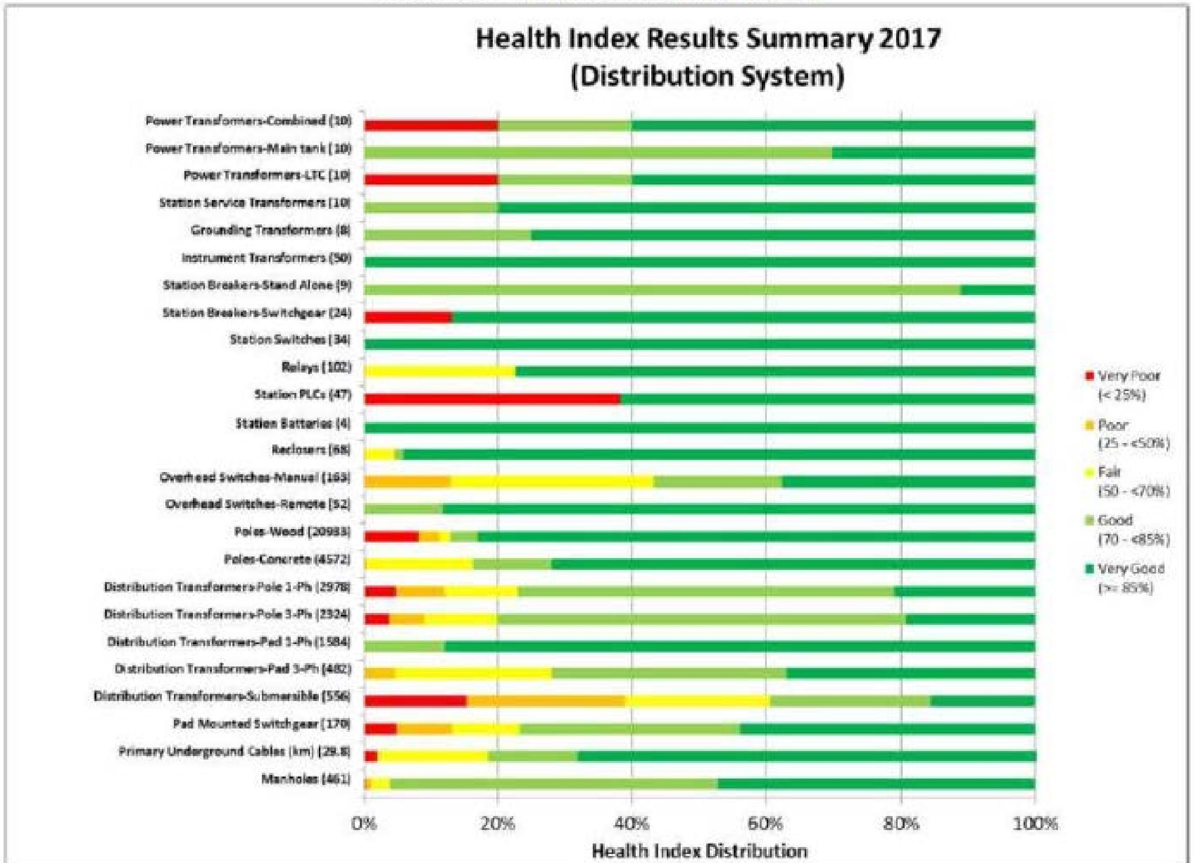
Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 110

Preamble:

EnWin Utilities provides Figure 20 for health index results of EnWin Utilities' Assets:

**Figure 20 Health of ENWIN's Assets**




Question:

a) For each of the 25 asset types presented in Figure 20, please provide the year-by-year costs and number of system renewal projects being undertaken over the bridge and forecast periods.

b) Please show how the priorities implied by spending and number of projects align with the health index results in Figure 20?

## Response:

a) Please see the table below for year-by-year costs and number of system renewal projects being undertaken over the bridge and forecast periods.

| Asset Type | 2019 | | 2020 | | 2021 | | 2022 | | 2023 | | 2024 | | Total | | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Budget * | Projects | Budget | Projects | Budget | Projects | Budget | Projects | Budget | Projects | Budget | Projects | Budget | Projects | |
| Power Transformers - Combined ** | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | ACA had a data gap for the LTC maintenance. LTC maintenance records were located, resulting in no replacements required. |
| Station Service Transformers | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Grounding Transformers | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Instrument Transformers | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Station Breakers - Stand Alone | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Station Breakers - Switchgear | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | ACA had a data gap for the switchgear maintenance. Switchgear maintenance records were located resulting in no replacements required. |
| Station Switches | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Relays | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Station PLCs | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | Investment was made prior to 2019, no further replacement required. |
| Station Batteries | $ 50 | 1 | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ 51 | 1 | Redundant station battery banks |
| Reclosers | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Overhead Switches - Manual | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | Annual inspection and operation of load break switches. Maintenance performed as needed to keep switches in safe working condition. |
| Overhead Switches - Remote | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | No investment required |
| Poles - Wood & Concrete *** | $ 2,950 | 536 | $3,300 | 600 | $3,300 | 600 | $3,300 | 600 | $3,300 | 600 | $3,300 | 600 | $19,450 | 3,536 | Level of spending is appropriate |
| Distribution Transformers - Pole 1-Ph | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | Run to failure, no investment required under sustainment |
| Distribution Transformers - Pole 3Ph | $ 130 | 5 | $ 130 | 5 | $ 130 | 5 | $ 130 | 5 | $ 130 | 5 | $ 130 | 5 | $ 805 | 30 | Level of spending is appropriate |
| Distribution Transformers - Pad 1Ph | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | $ - | - | Run to failure, no investment required under sustainment |
| Distribution Transformers - Pad 3Ph | $ 280 | 7 | $ 255 | 6 | $ 277 | 7 | $ 297 | 7 | $ 256 | 6 | $ 256 | 6 | $ 1,660 | 39 | Level of spending is appropriate |
| Distribution Transformers - Submersible | $ 690 | 30 | $ 690 | 30 | $ 690 | 30 | $ 690 | 30 | $ 690 | 30 | $ 690 | 30 | $ 4,320 | 180 | Level of spending is appropriate |
| Pad Mounted Switchgear | $ 325 | 9 | $ 325 | 6 | $ 325 | 3 | $ 325 | 4 | $ 325 | 15 | $ 325 | 5 | $ 1,992 | 42 | Level of spending is appropriate |
| Primary Underground Cables | $ 120 | 2 | $ 512 | 1 | $1,500 | 6 | $ 841 | 3 | $ 394 | 3 | $ - | - | $ 3,382 | 15 | Level of spending is appropriate |
| Manholes | $ 150 | 6 | $ 150 | 14 | $ 150 | 7 | $ 150 | 10 | $ 150 | 14 | $ 150 | 6 | $ 957 | 57 | Level of spending is appropriate |

*All dollar amounts in 000's
**Power transformers – Combined includes both main tank and LTC lines in the ACA
*** Wood and concrete poles have been combined into one line to match our budgeting practices.

b) The notes column in the table above highlights the priorities implied by spending with the health index results. In the event that the ACA and spending do not align, reasoning is given.

## 2 - OEB Staff - 42

Reference:

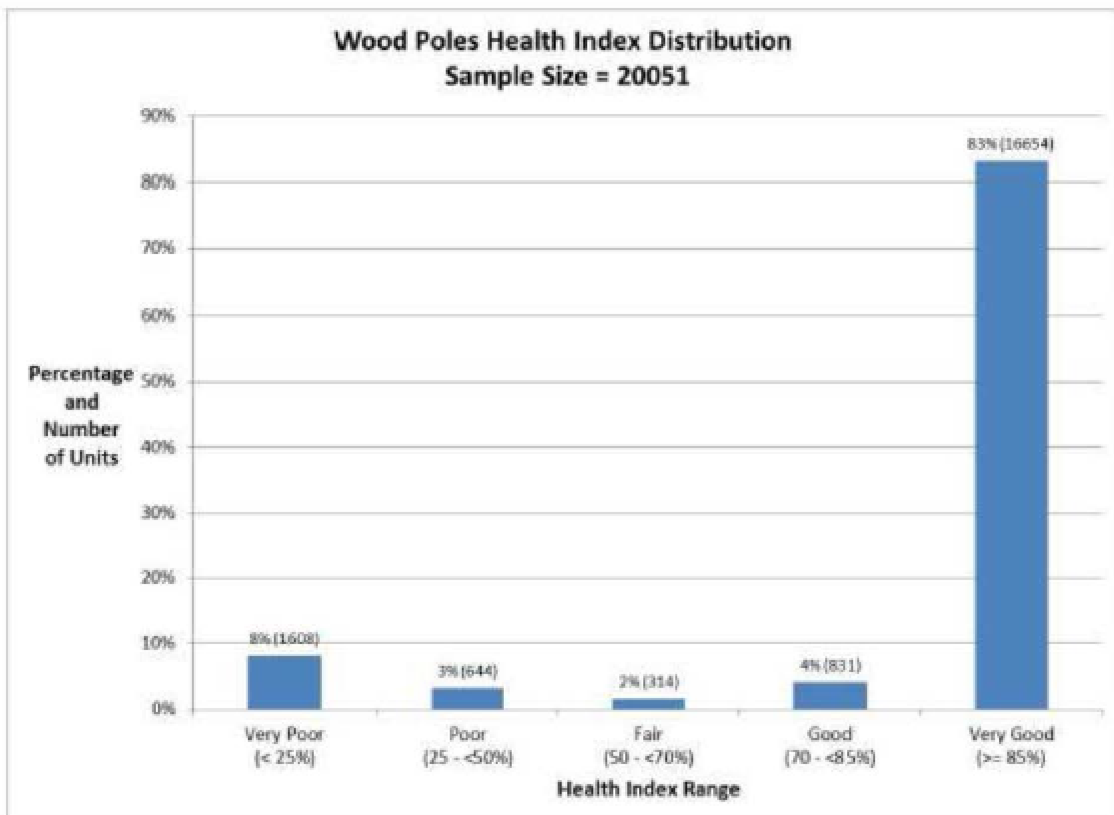
Exhibit 2: Rate Base, Attachment 2A, Page 120

Exhibit 2: Rate Base, Attachment 2A, Page 285

Preamble:

EnWin Utilities provides Table 33 for Wood Poles Health Index Distribution:

**Figure 33 Wood Poles Health Index Distribution**




EnWin Utilities explains the pole expenditures as below:

In 2015 and 2016, ENWIN undertook a mass re-inspection of its pole fleet as the data that had been maintained for those assets had become unreliable. This work was completed, and the database of pole health information is now improved and reliable. That database currently indicates that there are approximately 2,750 poles that are flagged for action ["FFA"]. That is a sufficient number of poles to support the level of expenditure proposed for the Test Year and the Forecast Period of the DSP. Additionally, it is expected that as that period progresses, there will be more poles that fall into the FFA category.

Question:

a) Please explain why EnWin Utilities' pole health index distribution shows significantly fewer poles in the middle of the distribution (i.e. poor/fair/good health index) relative to the Very Poor and Very Good health index categories.

b) Is this distribution caused by a demographic distribution skewed towards new poles?

c) Has EnWin Utilities historically focused its efforts on replacing poles assessed as being in Poor, Fair and Good condition, and allowing poles in Very Poor condition to run to fail?

d) Why did the pole fleet data become unreliable in 2015/16?

e) Have outages caused by pole failures contributed negatively to an otherwise favourable reliability performance trend over the historical period?

> i. If yes, please provide evidence to demonstrate the relationship between pole failures and the deteriorating performance trend.
>
> ii. If no, has EnWin Utilities made any attempt to pace the investments in addressing its FFA pole inventory over a longer period, to better align the program with actual historical pole performance?

f) What is the makeup of the 2,750 FFA poles, in terms of their health index category? As part of your answer, please list 2,750 FFA poles by health index.

Response:

a) & b)

With reference to the below attached figures 12-3 and 12-4 from the Asset Condition Study prepared by Kinectrics for ENWIN in 2017, the average age of ENWIN's wood pole population was determined to be 24 years, and for concrete poles was determined to be 23 years. When considering the range of age for ENWIN's pole population (0 to ~80 years for wood, and 0 to ~70 years for concrete), the age demographic is indeed skewed towards younger poles. This skewing of the pole population's age demographic towards younger poles tends to place more poles in the very good health category. Generally, as long as the preservatives that have been applied to the poles is active, the poles remain in very good condition. Once that preservative has become ineffective, the poles will deteriorate relatively quickly which pushes the poles towards the poor end of the health index spectrum. The Kinectrics determined lifespan of wood poles is 45 years based on industry standard; according to the pole inspection database, 15% of ENWIN's wood poles have reached or exceeded this end of life bench mark. This corresponds to the statistics presented in Table 33 which indicates that 8% of wood poles are in very poor condition.

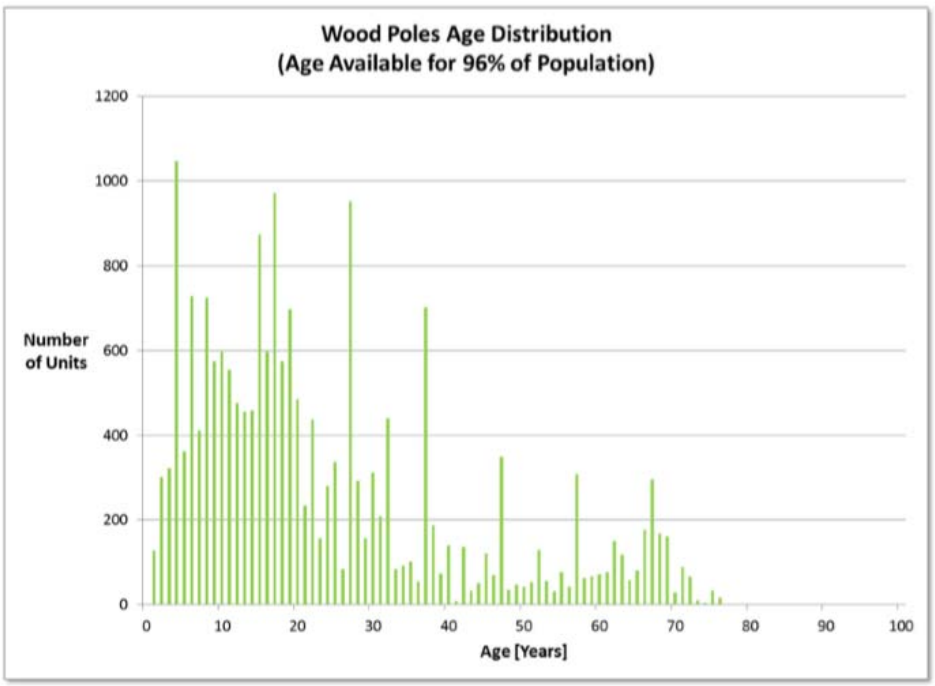



**Figure 12-3 Age Distribution – Poles (Wood)**

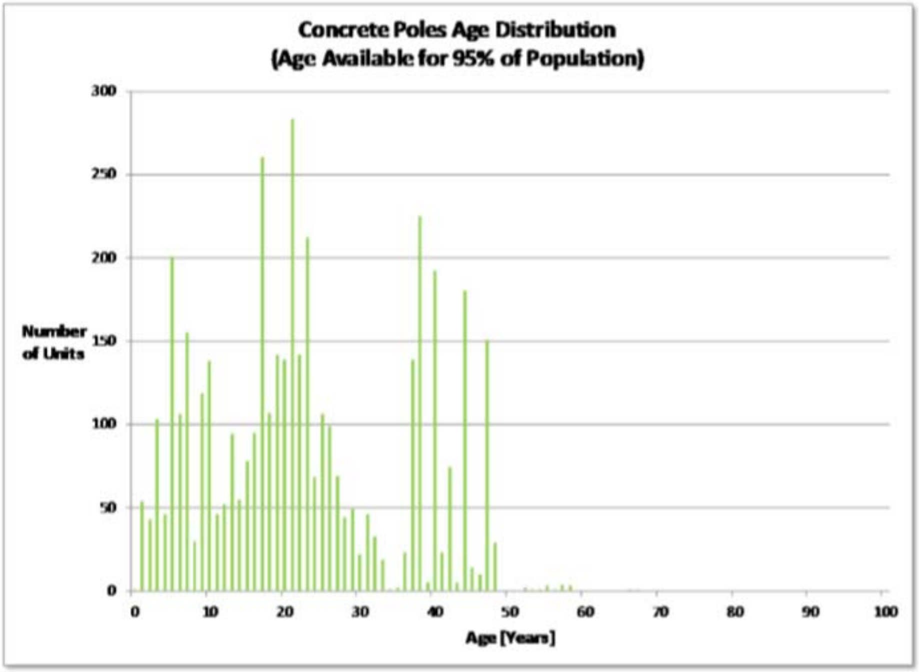



**Figure 12-4 Age Distribution – Poles (Concrete)**

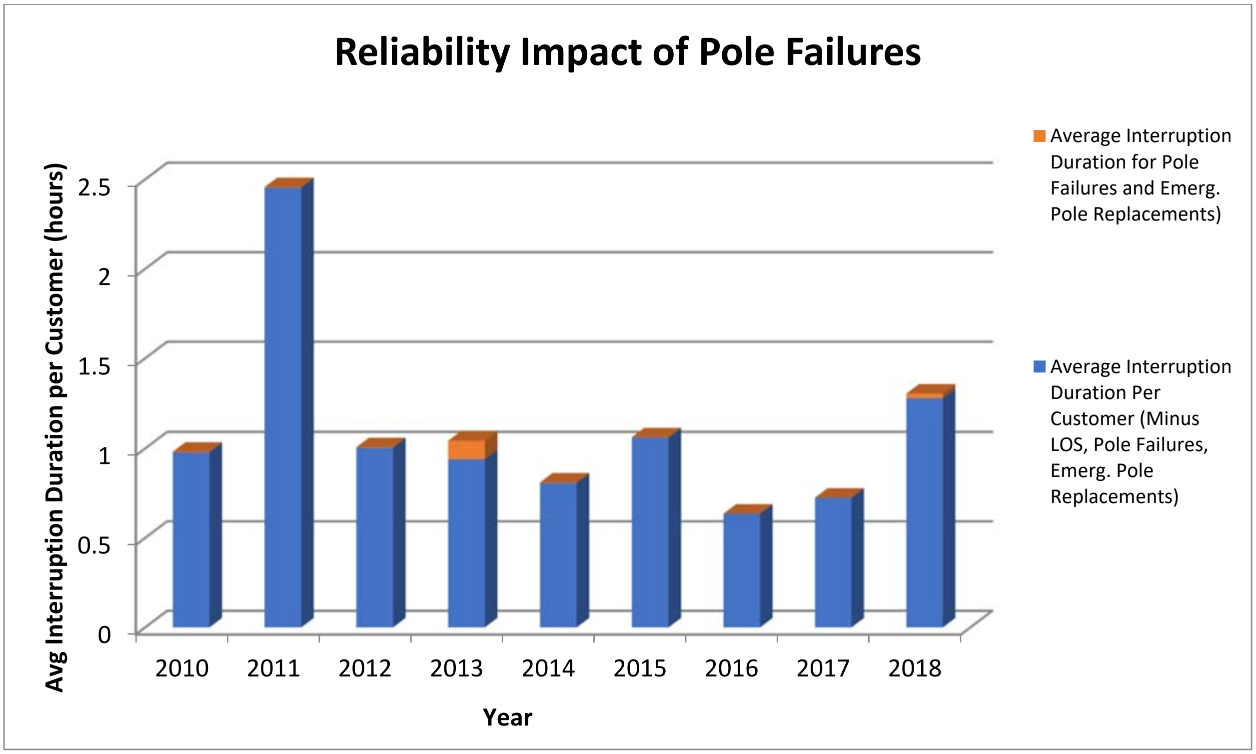
c) ENWIN has never and will never run poles to failure. ENWIN's key concern is public safety, and secondary to that, reliability. In the event of a pole failure, public safety is at risk as these poles could fall and injure or even kill someone, or damage property. Additionally, pole failures have the potential to take down other overhead infrastructure when they occur, which would negatively impact reliability. When possible, ENWIN makes efforts to find 'clusters' of poles for replacement, and combine their replacement with other overhead infrastructure sustainment or enhancement projects when possible. However, when this is not possible, ENWIN will carry out a single pole or emergency pole replacement.

d) Please see the response to AMPCO-5 (b).

e) Please see the table below.

| Years | SAIDI minus LOS | # Cust | Pole-Related Total Customer Hours of Outage | SAIDI Minus LOS & Pole Failures/Emerg Repairs | ∆ (Pole-Related / #Customers | % ∆ |
|---|---|---|---|---|---|---|
| 2010 | 0.9778 | 90078 | 322.53 | 0.9742 | -0.003581 | -0.3661 |
| 2011 | 2.4532 | 88797 | 278.73 | 2.4500 | -0.003139 | -0.1279 |
| 2012 | 1.0039 | 89823 | 267.68 | 1.0009 | -0.00298 | -0.2968 |
| 2013 | 0.9395 | 87406 | 9052.36 | 0.8359 | -0.103567 | -11.0236 |
| 2014 | 0.8063 | 87712 | 292.52 | 0.8029 | -0.003335 | -0.4136 |
| 2015 | 1.0606 | 87859 | 167.2 | 1.0586 | -0.001903 | -0.1794 |
| 2016 | 0.6355 | 87826 | 0 | 0.6355 | 0 | 0 |

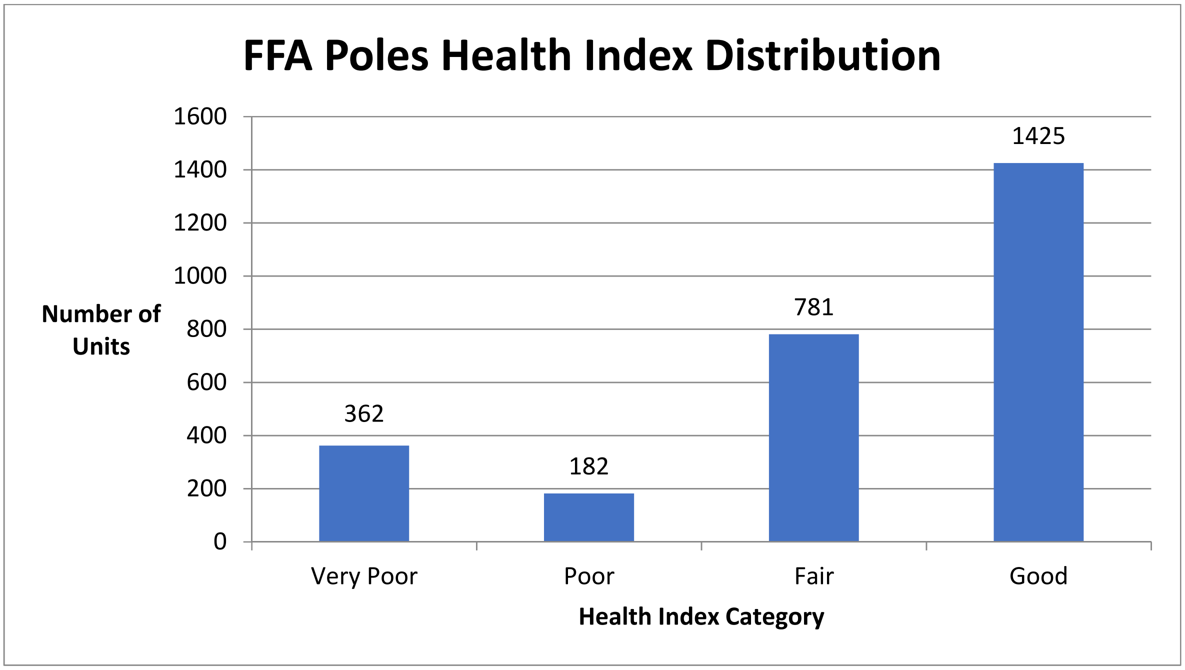
| | | | | | | |
|---|---|---|---|---|---|---|
| 2017 | 0.7243 | 88292 | 20.83 | 0.7240 | -0.000236 | -0.0325 |
| 2018 | 1.2767 | 90677 | 2344.03 | 1.2508 | -0.02585 | -2.0247 |
| **Average** | **1.0975** | | | **1.0815** | **0.0161** | **-1.6072** |




The above table and graph show the impact on ENWIN's SAIDI values of both pole failures causing immediate outages as a direct result of the failure, as well as outages required in order to complete emergency repairs on rotten/broken poles. These statistics were compiled by considering the effects of pole deterioration in isolation and when encountering adverse weather conditions. This information is compared against ENWIN's historical SAIDI values (minus Loss of Service (LOS) caused by Hydro One outages). Over 8 years, deteriorated poles contributed 0.0161 hours (1 minute) to the overall average interruption duration of 1.0975 hours (1 hour and 6 minutes). Notably, in 2013 pole failures contributed 0.1036 hours (6 minutes) of 0.9395 hours (56 minutes) of interruption duration per customer.

ENWIN works to ensure that investments in pole sustainment adequately balance fiscal limitations, system reliability and public safety, taking into account several factors such as historical failure rates, health index, risk, etc. in order to drive decision making. ENWIN has made efforts to maintain reliability and level capital investment in pole sustainment over the years by pre-emptively leveling investment based on projected end-of-life and failure rates. Sixty percent of ENWIN's distribution system is overhead construction, therefore, emphasis is put on maintaining this asset class in order to maintain reliability, strengthen against storms, and regard public safety as paramount as pole failures can result in significant safety risks.

f) Please see the graph and table below:




| Facility ID * | Health | HI Category |
|---|---|---|
| 20053895 | 0 | Very Poor |
| 20053950 | 0 | Very Poor |
| 20055112 | 0 | Very Poor |
| 20056032 | 0 | Very Poor |
| 20056738 | 0 | Very Poor |
| 20080887 | 0 | Very Poor |
| 20090443 | 0 | Very Poor |
| 20114333 | 0 | Very Poor |
| 20052286 | 0 | Very Poor |
| 20053103 | 0 | Very Poor |
| 20056063 | 0 | Very Poor |
| 20056064 | 0 | Very Poor |
| 20056774 | 0 | Very Poor |
| 20057307 | 0 | Very Poor |
| 20057598 | 0 | Very Poor |
| 20057971 | 0 | Very Poor |
| 20059523 | 0 | Very Poor |
| 20060328 | 0 | Very Poor |
| 20061055 | 0 | Very Poor |
| 20061068 | 0 | Very Poor |
| 20061090 | 0 | Very Poor |
| 20064551 | 0 | Very Poor |

| | | |
|---|---|---|
| 20065910 | 0 | Very Poor |
| 20066711 | 0 | Very Poor |
| 20066730 | 0 | Very Poor |
| 20066731 | 0 | Very Poor |
| 20066739 | 0 | Very Poor |
| 20067166 | 0 | Very Poor |
| 20067192 | 0 | Very Poor |
| 20067205 | 0 | Very Poor |
| 20074242 | 0 | Very Poor |
| 20080208 | 0 | Very Poor |
| 20086259 | 0 | Very Poor |
| 20087758 | 0 | Very Poor |
| 20088142 | 0 | Very Poor |
| 20088531 | 0 | Very Poor |
| 20090927 | 0 | Very Poor |
| 20090941 | 0 | Very Poor |
| 20091460 | 0 | Very Poor |
| 20103122 | 0 | Very Poor |
| 20103127 | 0 | Very Poor |
| 20106798 | 0 | Very Poor |
| 20108653 | 0 | Very Poor |
| 20109482 | 0 | Very Poor |
| 20110795 | 0 | Very Poor |
| 20112050 | 0 | Very Poor |
| 20113480 | 0 | Very Poor |
| 20114647 | 0 | Very Poor |
| 20055822 | 0 | Very Poor |
| 20063675 | 0 | Very Poor |
| 20064722 | 0 | Very Poor |
| 20073110 | 0 | Very Poor |
| 20086719 | 0 | Very Poor |
| 20059915 | 0.01 | Very Poor |
| 20060197 | 0.01 | Very Poor |
| 20057650 | 0.02 | Very Poor |
| 20057734 | 0.08 | Very Poor |
| 20061930 | 0.08 | Very Poor |
| 20074324 | 0.08 | Very Poor |
| 20106772 | 0.08 | Very Poor |
| 20051924 | 0.09 | Very Poor |
| 20108583 | 0.09513 | Very Poor |
| 20082367 | 0.1 | Very Poor |
| 20055114 | 0.1 | Very Poor |
| 20055118 | 0.1 | Very Poor |
| 20079195 | 0.1 | Very Poor |
| 20106560 | 0.1 | Very Poor |
| 20081125 | 0.1 | Very Poor |
| 20073630 | 0.1 | Very Poor |
| 20114699 | 0.1 | Very Poor |
| 20081253 | 0.1 | Very Poor |
| 20112028 | 0.1 | Very Poor |
| 20064502 | 0.1 | Very Poor |
| 20052851 | 0.1 | Very Poor |
| 20109889 | 0.1 | Very Poor |
| 20109886 | 0.1 | Very Poor |
| 20114102 | 0.1 | Very Poor |
| 20114181 | 0.1 | Very Poor |
| 20114182 | 0.1 | Very Poor |
| 20070295 | 0.1 | Very Poor |

| | | |
|---|---|---|
| 20112303 | 0.1 | Very Poor |
| 20070385 | 0.1 | Very Poor |
| 20077605 | 0.1 | Very Poor |
| 20077606 | 0.1 | Very Poor |
| 20078371 | 0.1 | Very Poor |
| 20072293 | 0.1 | Very Poor |
| 20112366 | 0.1 | Very Poor |
| 20065532 | 0.1 | Very Poor |
| 20065531 | 0.1 | Very Poor |
| 20050113 | 0.1 | Very Poor |
| 20056965 | 0.1 | Very Poor |
| 20056947 | 0.1 | Very Poor |
| 20055046 | 0.1 | Very Poor |
| 20070168 | 0.1 | Very Poor |
| 20056065 | 0.1 | Very Poor |
| 20065416 | 0.1 | Very Poor |
| 20065393 | 0.1 | Very Poor |
| 20062952 | 0.1 | Very Poor |
| 20063053 | 0.1 | Very Poor |
| 20055925 | 0.1 | Very Poor |
| 20055964 | 0.1 | Very Poor |
| 20066812 | 0.1 | Very Poor |
| 20067816 | 0.1 | Very Poor |
| 20066771 | 0.1 | Very Poor |
| 20066769 | 0.1 | Very Poor |
| 20066767 | 0.1 | Very Poor |
| 20053890 | 0.1 | Very Poor |
| 20053877 | 0.1 | Very Poor |
| 20066815 | 0.1 | Very Poor |
| 20066814 | 0.1 | Very Poor |
| 20066813 | 0.1 | Very Poor |
| 20080907 | 0.1 | Very Poor |
| 20090537 | 0.1 | Very Poor |
| 20081024 | 0.1 | Very Poor |
| 20108285 | 0.1 | Very Poor |
| 20061960 | 0.1 | Very Poor |
| 20089389 | 0.1 | Very Poor |
| 20089399 | 0.1 | Very Poor |
| 20058990 | 0.1 | Very Poor |
| 20058893 | 0.1 | Very Poor |
| 20058936 | 0.1 | Very Poor |
| 20072150 | 0.1 | Very Poor |
| 20108283 | 0.1 | Very Poor |
| 20090366 | 0.1 | Very Poor |
| 20057843 | 0.1 | Very Poor |
| 20064563 | 0.1 | Very Poor |
| 20064562 | 0.1 | Very Poor |
| 20090852 | 0.1 | Very Poor |
| 20057746 | 0.1 | Very Poor |
| 20090077 | 0.1 | Very Poor |
| 20054249 | 0.1 | Very Poor |
| 20053585 | 0.1 | Very Poor |
| 20083348 | 0.1 | Very Poor |
| 20052028 | 0.1 | Very Poor |
| 20102920 | 0.1 | Very Poor |
| 20059360 | 0.1 | Very Poor |
| 20061742 | 0.1 | Very Poor |
| 20088110 | 0.1 | Very Poor |

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| 20090631 | 0.1 | Very Poor |
| 20102934 | 0.1 | Very Poor |
| 20081861 | 0.1 | Very Poor |
| 20086261 | 0.1 | Very Poor |
| 20114157 | 0.1 | Very Poor |
| 20088120 | 0.1 | Very Poor |
| 20064880 | 0.1 | Very Poor |
| 20055042 | 0.1 | Very Poor |
| 20061612 | 0.1 | Very Poor |
| 20057241 | 0.1 | Very Poor |
| 20066685 | 0.1 | Very Poor |
| 20058010 | 0.1 | Very Poor |
| 20113154 | 0.1 | Very Poor |
| 20112360 | 0.1 | Very Poor |
| 20078370 | 0.1 | Very Poor |
| 20062624 | 0.1 | Very Poor |
| 20079950 | 0.1 | Very Poor |
| 20090509 | 0.1 | Very Poor |
| 20113826 | 0.1 | Very Poor |
| 20088145 | 0.1 | Very Poor |
| 20050105 | 0.1 | Very Poor |
| 20114129 | 0.1 | Very Poor |
| 20073522 | 0.1 | Very Poor |
| 20087052 | 0.1 | Very Poor |
| 20061743 | 0.1 | Very Poor |
| 20064733 | 0.1 | Very Poor |
| 20089662 | 0.1 | Very Poor |
| 20053586 | 0.1 | Very Poor |
| 20102898 | 0.1 | Very Poor |
| 20109953 | 0.1 | Very Poor |
| 20112220 | 0.1 | Very Poor |
| 20112405 | 0.1 | Very Poor |
| 20062081 | 0.1 | Very Poor |
| 20064731 | 0.1 | Very Poor |
| 20077094 | 0.1 | Very Poor |
| 20108692 | 0.1 | Very Poor |
| 20081555 | 0.1 | Very Poor |
| 20088395 | 0.1 | Very Poor |
| 20080291 | 0.1 | Very Poor |
| 20053513 | 0.1 | Very Poor |
| 20058522 | 0.1 | Very Poor |
| 20112406 | 0.1 | Very Poor |
| 20066424 | 0.1 | Very Poor |
| 20066426 | 0.1 | Very Poor |
| 20066428 | 0.1 | Very Poor |
| 20079211 | 0.1 | Very Poor |
| 20079374 | 0.1 | Very Poor |
| 20079375 | 0.1 | Very Poor |
| 20081250 | 0.1 | Very Poor |
| 20081255 | 0.1 | Very Poor |
| 20102995 | 0.1 | Very Poor |
| 20106416 | 0.1 | Very Poor |
| 20111789 | 0.1 | Very Poor |
| 20050436 | 0.1 | Very Poor |
| 20052790 | 0.1 | Very Poor |
| 20053383 | 0.1 | Very Poor |
| 20053386 | 0.1 | Very Poor |
| 20053399 | 0.1 | Very Poor |

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| 20053400 | 0.1 | Very Poor |
| 20054813 | 0.1 | Very Poor |
| 20055386 | 0.1 | Very Poor |
| 20057333 | 0.1 | Very Poor |
| 20060100 | 0.1 | Very Poor |
| 20061707 | 0.1 | Very Poor |
| 20061708 | 0.1 | Very Poor |
| 20061736 | 0.1 | Very Poor |
| 20061834 | 0.1 | Very Poor |
| 20062245 | 0.1 | Very Poor |
| 20063676 | 0.1 | Very Poor |
| 20064508 | 0.1 | Very Poor |
| 20064876 | 0.1 | Very Poor |
| 20065196 | 0.1 | Very Poor |
| 20065246 | 0.1 | Very Poor |
| 20065846 | 0.1 | Very Poor |
| 20065854 | 0.1 | Very Poor |
| 20065855 | 0.1 | Very Poor |
| 20065875 | 0.1 | Very Poor |
| 20066381 | 0.1 | Very Poor |
| 20066437 | 0.1 | Very Poor |
| 20066438 | 0.1 | Very Poor |
| 20066579 | 0.1 | Very Poor |
| 20066591 | 0.1 | Very Poor |
| 20066592 | 0.1 | Very Poor |
| 20066594 | 0.1 | Very Poor |
| 20066596 | 0.1 | Very Poor |
| 20066609 | 0.1 | Very Poor |
| 20066611 | 0.1 | Very Poor |
| 20066612 | 0.1 | Very Poor |
| 20066631 | 0.1 | Very Poor |
| 20066836 | 0.1 | Very Poor |
| 20068642 | 0.1 | Very Poor |
| 20068833 | 0.1 | Very Poor |
| 20068834 | 0.1 | Very Poor |
| 20068836 | 0.1 | Very Poor |
| 20068855 | 0.1 | Very Poor |
| 20073431 | 0.1 | Very Poor |
| 20075295 | 0.1 | Very Poor |
| 20075486 | 0.1 | Very Poor |
| 20079299 | 0.1 | Very Poor |
| 20079304 | 0.1 | Very Poor |
| 20079307 | 0.1 | Very Poor |
| 20079310 | 0.1 | Very Poor |
| 20079317 | 0.1 | Very Poor |
| 20079318 | 0.1 | Very Poor |
| 20079337 | 0.1 | Very Poor |
| 20079353 | 0.1 | Very Poor |
| 20079431 | 0.1 | Very Poor |
| 20079435 | 0.1 | Very Poor |
| 20079500 | 0.1 | Very Poor |
| 20079501 | 0.1 | Very Poor |
| 20079503 | 0.1 | Very Poor |
| 20079508 | 0.1 | Very Poor |
| 20079887 | 0.1 | Very Poor |
| 20079889 | 0.1 | Very Poor |
| 20079900 | 0.1 | Very Poor |
| 20079906 | 0.1 | Very Poor |

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| 20079924 | 0.1 | Very Poor |
| 20079925 | 0.1 | Very Poor |
| 20079934 | 0.1 | Very Poor |
| 20081222 | 0.1 | Very Poor |
| 20081237 | 0.1 | Very Poor |
| 20081270 | 0.1 | Very Poor |
| 20081354 | 0.1 | Very Poor |
| 20081379 | 0.1 | Very Poor |
| 20081380 | 0.1 | Very Poor |
| 20081381 | 0.1 | Very Poor |
| 20081382 | 0.1 | Very Poor |
| 20081383 | 0.1 | Very Poor |
| 20081384 | 0.1 | Very Poor |
| 20081385 | 0.1 | Very Poor |
| 20081389 | 0.1 | Very Poor |
| 20081391 | 0.1 | Very Poor |
| 20081416 | 0.1 | Very Poor |
| 20081436 | 0.1 | Very Poor |
| 20081437 | 0.1 | Very Poor |
| 20081438 | 0.1 | Very Poor |
| 20081439 | 0.1 | Very Poor |
| 20081442 | 0.1 | Very Poor |
| 20081512 | 0.1 | Very Poor |
| 20081520 | 0.1 | Very Poor |
| 20081885 | 0.1 | Very Poor |
| 20082120 | 0.1 | Very Poor |
| 20082157 | 0.1 | Very Poor |
| 20082160 | 0.1 | Very Poor |
| 20082162 | 0.1 | Very Poor |
| 20082230 | 0.1 | Very Poor |
| 20082247 | 0.1 | Very Poor |
| 20082499 | 0.1 | Very Poor |
| 20082523 | 0.1 | Very Poor |
| 20082635 | 0.1 | Very Poor |
| 20082637 | 0.1 | Very Poor |
| 20082671 | 0.1 | Very Poor |
| 20082675 | 0.1 | Very Poor |
| 20082700 | 0.1 | Very Poor |
| 20082720 | 0.1 | Very Poor |
| 20086376 | 0.1 | Very Poor |
| 20089096 | 0.1 | Very Poor |
| 20106310 | 0.1 | Very Poor |
| 20106313 | 0.1 | Very Poor |
| 20106355 | 0.1 | Very Poor |
| 20106411 | 0.1 | Very Poor |
| 20106412 | 0.1 | Very Poor |
| 20106413 | 0.1 | Very Poor |
| 20106476 | 0.1 | Very Poor |
| 20106564 | 0.1 | Very Poor |
| 20106566 | 0.1 | Very Poor |
| 20106587 | 0.1 | Very Poor |
| 20108586 | 0.1 | Very Poor |
| 20108588 | 0.1 | Very Poor |
| 20109569 | 0.1 | Very Poor |
| 20109928 | 0.1 | Very Poor |
| 20110059 | 0.1 | Very Poor |
| 20110060 | 0.1 | Very Poor |
| 20112031 | 0.1 | Very Poor |

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| 20114088 | 0.1 | Very Poor |
| 20114089 | 0.1 | Very Poor |
| 20114095 | 0.1 | Very Poor |
| 20114106 | 0.1 | Very Poor |
| 20114290 | 0.1 | Very Poor |
| 20114652 | 0.1 | Very Poor |
| 20115134 | 0.1 | Very Poor |
| 20115192 | 0.1 | Very Poor |
| 20117327 | 0.1 | Very Poor |
| 20117329 | 0.1 | Very Poor |
| 20058861 | 0.13 | Very Poor |
| 20053993 | 0.13 | Very Poor |
| 20057026 | 0.145692 | Very Poor |
| 20063025 | 0.15 | Very Poor |
| 20108587 | 0.15 | Very Poor |
| 20111170 | 0.15 | Very Poor |
| 20112030 | 0.15 | Very Poor |
| 20080886 | 0.154097 | Very Poor |
| 20109095 | 0.16 | Very Poor |
| 20056747 | 0.162289 | Very Poor |
| 20053392 | 0.17 | Very Poor |
| 20081636 | 0.17 | Very Poor |
| 20055029 | 0.18 | Very Poor |
| 20069558 | 0.18 | Very Poor |
| 20081754 | 0.18 | Very Poor |
| 20111605 | 0.18 | Very Poor |
| 20080901 | 0.183889 | Very Poor |
| 20090865 | 0.2 | Very Poor |
| 20064127 | 0.20093 | Very Poor |
| 20091244 | 0.206575 | Very Poor |
| 20068327 | 0.206575 | Very Poor |
| 20089553 | 0.21 | Very Poor |
| 20063547 | 0.21 | Very Poor |
| 20063810 | 0.21 | Very Poor |
| 20066559 | 0.21 | Very Poor |
| 20087377 | 0.21 | Very Poor |
| 20064652 | 0.21 | Very Poor |
| 20088447 | 0.21344 | Very Poor |
| 20064474 | 0.217745 | Very Poor |
| 20079504 | 0.22 | Very Poor |
| 20081653 | 0.22 | Very Poor |
| 20053397 | 0.23 | Very Poor |
| 20091220 | 0.23 | Very Poor |
| 20109682 | 0.23 | Very Poor |
| 20052807 | 0.232472 | Very Poor |
| 20090527 | 0.232472 | Very Poor |
| 20065973 | 0.234955 | Very Poor |
| 20107215 | 0.24 | Very Poor |
| 20087283 | 0.242311 | Very Poor |
| 20054829 | 0.25 | Poor |
| 20067411 | 0.25153 | Poor |
| 20068313 | 0.255782 | Poor |
| 20063626 | 0.26 | Poor |
| 20106877 | 0.26 | Poor |
| 20057289 | 0.26 | Poor |
| 20053769 | 0.27 | Poor |
| 20073952 | 0.27 | Poor |

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| 20059875 | 0.272206 | Poor |
| 20061735 | 0.28801 | Poor |
| 20066479 | 0.29 | Poor |
| 20066751 | 0.29 | Poor |
| 20080183 | 0.3 | Poor |
| 20088497 | 0.3 | Poor |
| 20091109 | 0.3 | Poor |
| 20056580 | 0.30275 | Poor |
| 20056586 | 0.30275 | Poor |
| 20080340 | 0.30275 | Poor |
| 20057706 | 0.31 | Poor |
| 20061853 | 0.31 | Poor |
| 20066452 | 0.31 | Poor |
| 20090881 | 0.31 | Poor |
| 20080909 | 0.313215 | Poor |
| 20068291 | 0.32 | Poor |
| 20073951 | 0.32 | Poor |
| 20090459 | 0.32 | Poor |
| 20091004 | 0.322359 | Poor |
| 20054918 | 0.32401 | Poor |
| 20064132 | 0.32401 | Poor |
| 20053105 | 0.33 | Poor |
| 20061067 | 0.33 | Poor |
| 20109419 | 0.332613 | Poor |
| 20102978 | 0.34 | Poor |
| 20072929 | 0.34 | Poor |
| 20079715 | 0.34 | Poor |
| 20088419 | 0.34 | Poor |
| 20090654 | 0.34237 | Poor |
| 20088467 | 0.344413 | Poor |
| 20066844 | 0.344413 | Poor |
| 20072516 | 0.344413 | Poor |
| 20057389 | 0.346754 | Poor |
| 20058407 | 0.35 | Poor |
| 20108319 | 0.35 | Poor |
| 20054103 | 0.350845 | Poor |
| 20068314 | 0.358649 | Poor |
| 20063804 | 0.358649 | Poor |
| 20088570 | 0.36 | Poor |
| 20073405 | 0.363607 | Poor |
| 20051771 | 0.37 | Poor |
| 20106537 | 0.372743 | Poor |
| 20108021 | 0.373843 | Poor |
| 20068196 | 0.373843 | Poor |
| 20089785 | 0.373843 | Poor |
| 20114219 | 0.38 | Poor |
| 20053900 | 0.38 | Poor |
| 20053509 | 0.38 | Poor |
| 20073406 | 0.38607 | Poor |
| 20073225 | 0.38607 | Poor |
| 20091000 | 0.389947 | Poor |
| 20109548 | 0.389947 | Poor |
| 20081458 | 0.39 | Poor |
| 20064746 | 0.39 | Poor |
| 20086390 | 0.39 | Poor |
| 20114114 | 0.39 | Poor |
| 20080240 | 0.394849 | Poor |
| 20061778 | 0.394849 | Poor |

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| 20081875 | 0.394849 | Poor |
| 20074747 | 0.394849 | Poor |
| 20114118 | 0.395916 | Poor |
| 20062329 | 0.399893 | Poor |
| 20059838 | 0.4 | Poor |
| 20070076 | 0.4 | Poor |
| 20051978 | 0.4 | Poor |
| 20061829 | 0.4 | Poor |
| 20074903 | 0.4 | Poor |
| 20055036 | 0.4 | Poor |
| 20073189 | 0.400198 | Poor |
| 20073188 | 0.400198 | Poor |
| 20090467 | 0.400198 | Poor |
| 20066845 | 0.400198 | Poor |
| 20056894 | 0.41 | Poor |
| 20066089 | 0.41 | Poor |
| 20079811 | 0.41 | Poor |
| 20114220 | 0.41 | Poor |
| 20089082 | 0.41 | Poor |
| 20050439 | 0.42 | Poor |
| 20053983 | 0.42 | Poor |
| 20061671 | 0.42 | Poor |
| 20063239 | 0.42 | Poor |
| 20066522 | 0.42 | Poor |
| 20077565 | 0.42 | Poor |
| 20079450 | 0.42 | Poor |
| 20089050 | 0.42 | Poor |
| 20109582 | 0.42 | Poor |
| 20110830 | 0.42 | Poor |
| 20064475 | 0.423478 | Poor |
| 20064476 | 0.423478 | Poor |
| 20073181 | 0.423478 | Poor |
| 20057183 | 0.423478 | Poor |
| 20050354 | 0.423478 | Poor |
| 20050512 | 0.423478 | Poor |
| 20065417 | 0.423478 | Poor |
| 20087854 | 0.423478 | Poor |
| 20066924 | 0.423478 | Poor |
| 20057795 | 0.423478 | Poor |
| 20057937 | 0.423478 | Poor |
| 20090486 | 0.423478 | Poor |
| 20057787 | 0.423478 | Poor |
| 20057796 | 0.423478 | Poor |
| 20108332 | 0.423478 | Poor |
| 20090531 | 0.429219 | Poor |
| 20066599 | 0.429219 | Poor |
| 20102951 | 0.429219 | Poor |
| 20053508 | 0.43 | Poor |
| 20064487 | 0.43 | Poor |
| 20081652 | 0.43 | Poor |
| 20109388 | 0.43 | Poor |
| 20073409 | 0.434673 | Poor |
| 20109884 | 0.434865 | Poor |
| 20089541 | 0.436719 | Poor |
| 20060135 | 0.44 | Poor |
| 20079686 | 0.44 | Poor |
| 20066422 | 0.443683 | Poor |
| 20078156 | 0.443683 | Poor |

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| 20080722 | 0.443683 | Poor |
| 20061154 | 0.443683 | Poor |
| 20057938 | 0.444668 | Poor |
| 20058018 | 0.45 | Poor |
| 20066527 | 0.45 | Poor |
| 20066560 | 0.45 | Poor |
| 20080136 | 0.45 | Poor |
| 20080903 | 0.45191 | Poor |
| 20061150 | 0.45741 | Poor |
| 20068326 | 0.459807 | Poor |
| 20102948 | 0.459807 | Poor |
| 20087115 | 0.46 | Poor |
| 20057290 | 0.46 | Poor |
| 20058181 | 0.46 | Poor |
| 20070260 | 0.46 | Poor |
| 20106895 | 0.46 | Poor |
| 20073403 | 0.460813 | Poor |
| 20065783 | 0.460813 | Poor |
| 20053311 | 0.46447 | Poor |
| 20057949 | 0.46447 | Poor |
| 20064543 | 0.466662 | Poor |
| 20088175 | 0.466662 | Poor |
| 20051205 | 0.47 | Poor |
| 20057259 | 0.47 | Poor |
| 20066052 | 0.47 | Poor |
| 20079560 | 0.47 | Poor |
| 20080591 | 0.47 | Poor |
| 20088085 | 0.47 | Poor |
| 20090268 | 0.471564 | Poor |
| 20054102 | 0.471564 | Poor |
| 20115621 | 0.4787 | Poor |
| 20054179 | 0.478739 | Poor |
| 20061637 | 0.48 | Poor |
| 20112090 | 0.48 | Poor |
| 20068271 | 0.481772 | Poor |
| 20079203 | 0.483519 | Poor |
| 20079205 | 0.483519 | Poor |
| 20062975 | 0.485997 | Poor |
| 20088393 | 0.488508 | Poor |
| 20079367 | 0.49 | Poor |
| 20057630 | 0.49 | Poor |
| 20060046 | 0.49 | Poor |
| 20061089 | 0.49 | Poor |
| 20061618 | 0.49 | Poor |
| 20063641 | 0.49 | Poor |
| 20065980 | 0.49 | Poor |
| 20066468 | 0.49 | Poor |
| 20073280 | 0.49 | Poor |
| 20073426 | 0.49 | Poor |
| 20080277 | 0.49 | Poor |
| 20102846 | 0.49 | Poor |
| 20113327 | 0.49 | Poor |
| 20070299 | 0.491961 | Poor |
| 20090998 | 0.491961 | Poor |
| 20090549 | 0.491961 | Poor |
| 20078153 | 0.492901 | Poor |
| 20111982 | 0.494755 | Poor |
| 20066811 | 0.495212 | Poor |

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| 20065450 | 0.5 | Fair |
| 20079358 | 0.5 | Fair |
| 20079359 | 0.5 | Fair |
| 20079360 | 0.5 | Fair |
| 20082435 | 0.5 | Fair |
| 20082783 | 0.5 | Fair |
| 20106300 | 0.5 | Fair |
| 20050483 | 0.5 | Fair |
| 20051593 | 0.5 | Fair |
| 20051646 | 0.5 | Fair |
| 20052850 | 0.5 | Fair |
| 20053385 | 0.5 | Fair |
| 20053389 | 0.5 | Fair |
| 20053391 | 0.5 | Fair |
| 20053396 | 0.5 | Fair |
| 20053398 | 0.5 | Fair |
| 20055784 | 0.5 | Fair |
| 20055812 | 0.5 | Fair |
| 20060232 | 0.5 | Fair |
| 20061787 | 0.5 | Fair |
| 20061788 | 0.5 | Fair |
| 20061824 | 0.5 | Fair |
| 20061827 | 0.5 | Fair |
| 20063812 | 0.5 | Fair |
| 20063816 | 0.5 | Fair |
| 20065876 | 0.5 | Fair |
| 20066446 | 0.5 | Fair |
| 20066451 | 0.5 | Fair |
| 20066461 | 0.5 | Fair |
| 20066480 | 0.5 | Fair |
| 20066804 | 0.5 | Fair |
| 20066834 | 0.5 | Fair |
| 20068644 | 0.5 | Fair |
| 20068832 | 0.5 | Fair |
| 20068835 | 0.5 | Fair |
| 20068845 | 0.5 | Fair |
| 20069391 | 0.5 | Fair |
| 20073425 | 0.5 | Fair |
| 20075460 | 0.5 | Fair |
| 20075462 | 0.5 | Fair |
| 20075464 | 0.5 | Fair |
| 20079322 | 0.5 | Fair |
| 20079470 | 0.5 | Fair |
| 20079489 | 0.5 | Fair |
| 20079959 | 0.5 | Fair |
| 20079982 | 0.5 | Fair |
| 20080505 | 0.5 | Fair |
| 20080506 | 0.5 | Fair |
| 20080507 | 0.5 | Fair |
| 20080847 | 0.5 | Fair |
| 20081195 | 0.5 | Fair |
| 20081211 | 0.5 | Fair |
| 20081212 | 0.5 | Fair |
| 20081231 | 0.5 | Fair |
| 20081264 | 0.5 | Fair |
| 20081376 | 0.5 | Fair |
| 20081377 | 0.5 | Fair |
| 20081378 | 0.5 | Fair |

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| 20081386 | 0.5 | Fair |
| 20081387 | 0.5 | Fair |
| 20081401 | 0.5 | Fair |
| 20081444 | 0.5 | Fair |
| 20081635 | 0.5 | Fair |
| 20081721 | 0.5 | Fair |
| 20081722 | 0.5 | Fair |
| 20081955 | 0.5 | Fair |
| 20081961 | 0.5 | Fair |
| 20082163 | 0.5 | Fair |
| 20082164 | 0.5 | Fair |
| 20082165 | 0.5 | Fair |
| 20082167 | 0.5 | Fair |
| 20082249 | 0.5 | Fair |
| 20082251 | 0.5 | Fair |
| 20082459 | 0.5 | Fair |
| 20082482 | 0.5 | Fair |
| 20082491 | 0.5 | Fair |
| 20082493 | 0.5 | Fair |
| 20082495 | 0.5 | Fair |
| 20082498 | 0.5 | Fair |
| 20082500 | 0.5 | Fair |
| 20082634 | 0.5 | Fair |
| 20082674 | 0.5 | Fair |
| 20083466 | 0.5 | Fair |
| 20086378 | 0.5 | Fair |
| 20087291 | 0.5 | Fair |
| 20087941 | 0.5 | Fair |
| 20089094 | 0.5 | Fair |
| 20106396 | 0.5 | Fair |
| 20106403 | 0.5 | Fair |
| 20106415 | 0.5 | Fair |
| 20106446 | 0.5 | Fair |
| 20106595 | 0.5 | Fair |
| 20106596 | 0.5 | Fair |
| 20107090 | 0.5 | Fair |
| 20108768 | 0.5 | Fair |
| 20109655 | 0.5 | Fair |
| 20111488 | 0.5 | Fair |
| 20111990 | 0.5 | Fair |
| 20114186 | 0.5 | Fair |
| 20114700 | 0.5 | Fair |
| 20080874 | 0.500759 | Fair |
| 20066429 | 0.502321 | Fair |
| 20073404 | 0.502321 | Fair |
| 20080788 | 0.502321 | Fair |
| 20055008 | 0.502321 | Fair |
| 20066462 | 0.50392 | Fair |
| 20079596 | 0.507779 | Fair |
| 20113479 | 0.509835 | Fair |
| 20052981 | 0.51 | Fair |
| 20070273 | 0.51 | Fair |
| 20081091 | 0.51 | Fair |
| 20090094 | 0.51 | Fair |
| 20106369 | 0.513062 | Fair |
| 20112494 | 0.513062 | Fair |
| 20114334 | 0.515099 | Fair |
| 20113951 | 0.515099 | Fair |

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| 20055121 | 0.51677 | Fair |
| 20072983 | 0.51677 | Fair |
| 20081149 | 0.52 | Fair |
| 20081151 | 0.52 | Fair |
| 20052361 | 0.52 | Fair |
| 20073424 | 0.52 | Fair |
| 20077820 | 0.52 | Fair |
| 20081578 | 0.52 | Fair |
| 20082667 | 0.52 | Fair |
| 20086372 | 0.52 | Fair |
| 20086384 | 0.52 | Fair |
| 20087147 | 0.52 | Fair |
| 20112146 | 0.52 | Fair |
| 20112147 | 0.52 | Fair |
| 20114131 | 0.52 | Fair |
| 20114436 | 0.52 | Fair |
| 20078154 | 0.52411 | Fair |
| 20080964 | 0.525682 | Fair |
| 20082008 | 0.525682 | Fair |
| 20058279 | 0.53 | Fair |
| 20079538 | 0.53 | Fair |
| 20057122 | 0.53 | Fair |
| 20087491 | 0.53 | Fair |
| 20112091 | 0.53 | Fair |
| 20114160 | 0.53 | Fair |
| 20073193 | 0.531271 | Fair |
| 20089396 | 0.531271 | Fair |
| 20073073 | 0.53472 | Fair |
| 20086821 | 0.536567 | Fair |
| 20073180 | 0.537467 | Fair |
| 20088359 | 0.539359 | Fair |
| 20061201 | 0.539359 | Fair |
| 20058780 | 0.539359 | Fair |
| 20089652 | 0.539359 | Fair |
| 20050577 | 0.54 | Fair |
| 20051959 | 0.54 | Fair |
| 20057261 | 0.54 | Fair |
| 20059961 | 0.54 | Fair |
| 20061620 | 0.54 | Fair |
| 20063943 | 0.54 | Fair |
| 20072582 | 0.54 | Fair |
| 20073429 | 0.54 | Fair |
| 20080421 | 0.54 | Fair |
| 20086357 | 0.54 | Fair |
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| 20114238 | 0.69 | Fair |
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| 20087461 | 0.6909 | Fair |
| 20057040 | 0.6909 | Fair |
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| 20091388 | 0.6953 | Fair |
| 20056430 | 0.6959 | Fair |
| 20068669 | 0.695933 | Fair |
| 20068670 | 0.695933 | Fair |
| 20073925 | 0.695933 | Fair |
| 20077959 | 0.695933 | Fair |
| 20086727 | 0.6968 | Fair |
| 20063475 | 0.696811 | Fair |
| 20052822 | 0.697 | Fair |
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| 20050297 | 0.6983 | Fair |
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| 20056725 | 0.703556 | Good |
| 20073150 | 0.7036 | Good |
| 20062950 | 0.706662 | Good |
| 20091490 | 0.7067 | Good |
| 20069277 | 0.707814 | Good |
| 20090530 | 0.7096 | Good |
| 20106299 | 0.71 | Good |
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| 20066672 | 0.71 | Good |

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| 20072525 | 0.7123 | Good |
| 20077909 | 0.7123 | Good |
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| 20062633 | 0.712347 | Good |
| 20063470 | 0.712347 | Good |
| 20079373 | 0.713034 | Good |

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| 20089035 | 0.717783 | Good |
| 20090262 | 0.717783 | Good |
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| 20114150 | 0.717783 | Good |
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| 20053892 | 0.723237 | Good |
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| 20081148 | 0.725262 | Good |
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| 20081223 | 0.73 | Good |
| 20081292 | 0.73 | Good |
| 20081373 | 0.73 | Good |
| 20081407 | 0.73 | Good |
| 20081412 | 0.73 | Good |
| 20081563 | 0.73 | Good |
| 20081577 | 0.73 | Good |
| 20081644 | 0.73 | Good |
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| 20081748 | 0.73 | Good |
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| 20082033 | 0.73 | Good |
| 20082055 | 0.73 | Good |
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| 20061732 | 0.731115 | Good |
| 20072290 | 0.731115 | Good |
| 20072985 | 0.731115 | Good |
| 20073079 | 0.731115 | Good |
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| 20113926 | 0.733628 | Good |
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| 20062416 | 0.73507 | Good |
| 20066417 | 0.7351 | Good |
| 20072699 | 0.7354 | Good |
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| 20081547 | 0.738567 | Good |
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| 20051155 | 0.7391 | Good |
| 20051160 | 0.7391 | Good |
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| 20081467 | 0.741365 | Good |
| 20073007 | 0.7414 | Good |
| 20060092 | 0.741526 | Good |
| 20052160 | 0.74196 | Good |
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| 20064728 | 0.743915 | Good |
| 20054787 | 0.7447 | Good |

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| 20111997 | 0.746094 | Good |
| 20112125 | 0.746094 | Good |
| 20072291 | 0.746094 | Good |
| 20072287 | 0.746094 | Good |
| 20056967 | 0.746094 | Good |
| 20113992 | 0.748078 | Good |
| 20061138 | 0.748078 | Good |
| 20072831 | 0.748078 | Good |
| 20073523 | 0.748078 | Good |
| 20080105 | 0.748078 | Good |
| 20114155 | 0.748078 | Good |
| 20052331 | 0.7481 | Good |
| 20070485 | 0.7481 | Good |
| 20067182 | 0.7481 | Good |
| 20067206 | 0.7481 | Good |
| 20090937 | 0.7481 | Good |
| 20090217 | 0.749 | Good |
| 20090621 | 0.749 | Good |
| 20070491 | 0.749034 | Good |
| 20075298 | 0.749034 | Good |
| 20052170 | 0.749263 | Good |
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| 20079357 | 0.75 | Good |
| 20079385 | 0.75 | Good |
| 20082373 | 0.75 | Good |
| 20082401 | 0.75 | Good |
| 20106343 | 0.75 | Good |
| 20050454 | 0.75 | Good |
| 20051701 | 0.75 | Good |
| 20051748 | 0.75 | Good |
| 20051755 | 0.75 | Good |
| 20051782 | 0.75 | Good |
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| 20057343 | 0.75 | Good |
| 20060063 | 0.75 | Good |
| 20060233 | 0.75 | Good |
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| 20063851 | 0.75 | Good |
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| 20065703 | 0.75 | Good |
| 20065825 | 0.75 | Good |
| 20066150 | 0.75 | Good |
| 20066151 | 0.75 | Good |
| 20066392 | 0.75 | Good |
| 20066449 | 0.75 | Good |

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| 20069398 | 0.75 | Good |
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| 20079260 | 0.75 | Good |
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| 20079332 | 0.75 | Good |
| 20079921 | 0.75 | Good |
| 20079973 | 0.75 | Good |
| 20079989 | 0.75 | Good |
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| 20089312 | 0.7507 | Good |
| 20057605 | 0.7512 | Good |
| 20060959 | 0.751231 | Good |

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| 20078155 | 0.751231 | Good |
| 20073081 | 0.751231 | Good |
| 20080899 | 0.751231 | Good |
| 20057028 | 0.751278 | Good |
| 20057020 | 0.751278 | Good |
| 20057017 | 0.751278 | Good |
| 20058977 | 0.751278 | Good |
| 20058933 | 0.751278 | Good |
| 20090372 | 0.751278 | Good |
| 20087487 | 0.751278 | Good |
| 20051169 | 0.7513 | Good |
| 20087949 | 0.7513 | Good |
| 20087955 | 0.7513 | Good |
| 20056808 | 0.7513 | Good |
| 20056941 | 0.7513 | Good |
| 20059808 | 0.7513 | Good |
| 20061892 | 0.7513 | Good |
| 20061894 | 0.7513 | Good |
| 20061947 | 0.7513 | Good |
| 20079879 | 0.7513 | Good |
| 20090731 | 0.7513 | Good |
| 20091136 | 0.7513 | Good |
| 20068292 | 0.7525 | Good |
| 20050007 | 0.7539 | Good |
| 20089847 | 0.7539 | Good |
| 20082770 | 0.753902 | Good |
| 20082684 | 0.754 | Good |
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| 20106368 | 0.757663 | Good |
| 20088421 | 0.7577 | Good |
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| 20060950 | 0.76 | Good |
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| 20108737 | 0.761073 | Good |
| 20082769 | 0.761073 | Good |
| 20082764 | 0.761073 | Good |
| 20082908 | 0.761073 | Good |
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| 20058216 | 0.7611 | Good |
| 20061366 | 0.7611 | Good |
| 20062189 | 0.7611 | Good |
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| 20079377 | 0.761654 | Good |
| 20052159 | 0.761654 | Good |
| 20066831 | 0.761654 | Good |
| 20056029 | 0.761654 | Good |
| 20052543 | 0.761654 | Good |
| 20068022 | 0.7617 | Good |
| 20058900 | 0.76248 | Good |
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| 20061681 | 0.764866 | Good |
| 20058660 | 0.7649 | Good |
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| 20078749 | 0.7672 | Good |
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| 20058421 | 0.767449 | Good |
| 20058070 | 0.7697 | Good |
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| 20088388 | 0.7697 | Good |
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| 20052156 | 0.77 | Good |
| 20072322 | 0.77 | Good |
| 20079410 | 0.77 | Good |
| 20079419 | 0.77 | Good |
| 20082302 | 0.77 | Good |
| 20050453 | 0.77 | Good |
| 20050459 | 0.77 | Good |
| 20051698 | 0.77 | Good |
| 20051700 | 0.77 | Good |
| 20051756 | 0.77 | Good |
| 20051996 | 0.77 | Good |
| 20055002 | 0.77 | Good |

| | | |
|---|---|---|
| 20055018 | 0.77 | Good |
| 20055040 | 0.77 | Good |
| 20057262 | 0.77 | Good |
| 20062413 | 0.77 | Good |
| 20063184 | 0.77 | Good |
| 20063532 | 0.77 | Good |
| 20064606 | 0.77 | Good |
| 20064636 | 0.77 | Good |
| 20064796 | 0.77 | Good |
| 20066145 | 0.77 | Good |
| 20066519 | 0.77 | Good |
| 20066523 | 0.77 | Good |
| 20067630 | 0.77 | Good |
| 20073152 | 0.77 | Good |
| 20073275 | 0.77 | Good |
| 20073911 | 0.77 | Good |
| 20073949 | 0.77 | Good |
| 20077144 | 0.77 | Good |
| 20077576 | 0.77 | Good |
| 20079305 | 0.77 | Good |
| 20079331 | 0.77 | Good |
| 20079734 | 0.77 | Good |
| 20079905 | 0.77 | Good |
| 20079915 | 0.77 | Good |
| 20080126 | 0.77 | Good |
| 20081705 | 0.77 | Good |
| 20081707 | 0.77 | Good |
| 20081717 | 0.77 | Good |
| 20082001 | 0.77 | Good |
| 20082010 | 0.77 | Good |
| 20082528 | 0.77 | Good |
| 20082530 | 0.77 | Good |
| 20082533 | 0.77 | Good |
| 20082548 | 0.77 | Good |
| 20082627 | 0.77 | Good |
| 20087405 | 0.77 | Good |
| 20087538 | 0.77 | Good |
| 20087614 | 0.77 | Good |
| 20087670 | 0.77 | Good |
| 20087905 | 0.77 | Good |
| 20088103 | 0.77 | Good |
| 20088113 | 0.77 | Good |
| 20090170 | 0.77 | Good |
| 20106354 | 0.77 | Good |
| 20052846 | 0.770276 | Good |
| 20073407 | 0.770276 | Good |
| 20065780 | 0.770276 | Good |
| 20072981 | 0.770276 | Good |
| 20066810 | 0.770276 | Good |
| 20064498 | 0.771199 | Good |
| 20089023 | 0.771326 | Good |
| 20082282 | 0.772103 | Good |
| 20078380 | 0.772103 | Good |
| 20056946 | 0.772103 | Good |
| 20060122 | 0.772103 | Good |
| 20080906 | 0.772103 | Good |
| 20090368 | 0.772103 | Good |
| 20057391 | 0.772103 | Good |

| | | |
|---|---|---|
| 20089535 | 0.772103 | Good |
| 20103154 | 0.774062 | Good |
| 20080112 | 0.775662 | Good |
| 20079233 | 0.7784 | Good |
| 20079356 | 0.7784 | Good |
| 20082763 | 0.7784 | Good |
| 20067746 | 0.7784 | Good |
| 20088367 | 0.7784 | Good |
| 20052943 | 0.7784 | Good |
| 20082582 | 0.77984 | Good |
| 20060945 | 0.77984 | Good |
| 20079228 | 0.78 | Good |
| 20079361 | 0.78 | Good |
| 20079386 | 0.78 | Good |
| 20079409 | 0.78 | Good |
| 20081456 | 0.78 | Good |
| 20082784 | 0.78 | Good |
| 20082400 | 0.78 | Good |
| 20082369 | 0.78 | Good |
| 20106306 | 0.78 | Good |
| 20055090 | 0.78 | Good |
| 20055111 | 0.78 | Good |
| 20055113 | 0.78 | Good |
| 20055116 | 0.78 | Good |
| 20055117 | 0.78 | Good |
| 20055119 | 0.78 | Good |
| 20055122 | 0.78 | Good |
| 20055124 | 0.78 | Good |
| 20079171 | 0.78 | Good |
| 20079194 | 0.78 | Good |
| 20079196 | 0.78 | Good |
| 20111932 | 0.78 | Good |
| 20082317 | 0.78 | Good |
| 20082331 | 0.78 | Good |
| 20103151 | 0.78 | Good |
| 20082288 | 0.78 | Good |
| 20106385 | 0.78 | Good |
| 20081123 | 0.78 | Good |
| 20081122 | 0.78 | Good |
| 20106591 | 0.78 | Good |
| 20064503 | 0.78 | Good |
| 20072701 | 0.78 | Good |
| 20080116 | 0.78 | Good |
| 20060952 | 0.78 | Good |
| 20060953 | 0.78 | Good |
| 20060944 | 0.78 | Good |
| 20060946 | 0.78 | Good |
| 20087151 | 0.78 | Good |
| 20053479 | 0.78 | Good |
| 20052260 | 0.78 | Good |
| 20072294 | 0.78 | Good |
| 20072292 | 0.78 | Good |
| 20072288 | 0.78 | Good |
| 20078315 | 0.78 | Good |
| 20052169 | 0.78 | Good |
| 20072323 | 0.78 | Good |
| 20072295 | 0.78 | Good |
| 20072289 | 0.78 | Good |

| | | |
|---|---|---|
| 20076509 | 0.78 | Good |
| 20112437 | 0.78 | Good |
| 20066962 | 0.78 | Good |
| 20065533 | 0.78 | Good |
| 20068169 | 0.78 | Good |
| 20056959 | 0.78 | Good |
| 20056960 | 0.78 | Good |
| 20056961 | 0.78 | Good |
| 20056962 | 0.78 | Good |
| 20056963 | 0.78 | Good |
| 20057027 | 0.78 | Good |
| 20056943 | 0.78 | Good |
| 20057007 | 0.78 | Good |
| 20054919 | 0.78 | Good |
| 20067063 | 0.78 | Good |
| 20067062 | 0.78 | Good |
| 20067010 | 0.78 | Good |
| 20067054 | 0.78 | Good |
| 20065778 | 0.78 | Good |
| 20065787 | 0.78 | Good |
| 20065776 | 0.78 | Good |
| 20065781 | 0.78 | Good |
| 20065784 | 0.78 | Good |
| 20065785 | 0.78 | Good |
| 20056068 | 0.78 | Good |
| 20073089 | 0.78 | Good |
| 20073088 | 0.78 | Good |
| 20073087 | 0.78 | Good |
| 20073086 | 0.78 | Good |
| 20089404 | 0.78 | Good |
| 20113949 | 0.78 | Good |
| 20062943 | 0.78 | Good |
| 20065394 | 0.78 | Good |
| 20065392 | 0.78 | Good |
| 20067809 | 0.78 | Good |
| 20067808 | 0.78 | Good |
| 20051127 | 0.78 | Good |
| 20088351 | 0.78 | Good |
| 20062959 | 0.78 | Good |
| 20062958 | 0.78 | Good |
| 20062953 | 0.78 | Good |
| 20062949 | 0.78 | Good |
| 20062986 | 0.78 | Good |
| 20062982 | 0.78 | Good |
| 20062978 | 0.78 | Good |
| 20055927 | 0.78 | Good |
| 20055705 | 0.78 | Good |
| 20055878 | 0.78 | Good |
| 20055877 | 0.78 | Good |
| 20055963 | 0.78 | Good |
| 20055902 | 0.78 | Good |
| 20055900 | 0.78 | Good |
| 20089049 | 0.78 | Good |
| 20056008 | 0.78 | Good |
| 20055962 | 0.78 | Good |
| 20055911 | 0.78 | Good |
| 20089003 | 0.78 | Good |
| 20103107 | 0.78 | Good |

| | | |
|---|---|---|
| 20066772 | 0.78 | Good |
| 20089447 | 0.78 | Good |
| 20053891 | 0.78 | Good |
| 20053883 | 0.78 | Good |
| 20053880 | 0.78 | Good |
| 20053879 | 0.78 | Good |
| 20111336 | 0.78 | Good |
| 20063403 | 0.78 | Good |
| 20063484 | 0.78 | Good |
| 20090258 | 0.78 | Good |
| 20090202 | 0.78 | Good |
| 20067191 | 0.78 | Good |
| 20090539 | 0.78 | Good |
| 20081003 | 0.78 | Good |
| 20058896 | 0.78 | Good |
| 20089983 | 0.78 | Good |
| 20058948 | 0.78 | Good |
| 20058949 | 0.78 | Good |
| 20058959 | 0.78 | Good |
| 20058975 | 0.78 | Good |
| 20067273 | 0.78 | Good |
| 20090364 | 0.78 | Good |
| 20057841 | 0.78 | Good |
| 20057842 | 0.78 | Good |
| 20057844 | 0.78 | Good |
| 20057794 | 0.78 | Good |
| 20064556 | 0.78 | Good |
| 20090359 | 0.78 | Good |
| 20090361 | 0.78 | Good |
| 20090379 | 0.78 | Good |
| 20090369 | 0.78 | Good |
| 20090367 | 0.78 | Good |
| 20057744 | 0.78 | Good |
| 20057747 | 0.78 | Good |
| 20084017 | 0.78 | Good |
| 20084018 | 0.78 | Good |
| 20053307 | 0.78 | Good |
| 20059831 | 0.78 | Good |
| 20059836 | 0.78 | Good |
| 20079376 | 0.781678 | Good |
| 20056754 | 0.781678 | Good |
| 20082344 | 0.782939 | Good |
| 20082316 | 0.78305 | Good |
| 20068180 | 0.783075 | Good |
| 20110311 | 0.786972 | Good |
| 20082299 | 0.789628 | Good |
| 20082273 | 0.789628 | Good |
| 20079387 | 0.791945 | Good |
| 20052310 | 0.792316 | Good |
| 20052961 | 0.792726 | Good |
| 20070290 | 0.794473 | Good |
| 20065567 | 0.794473 | Good |
| 20062905 | 0.794814 | Good |
| 20081121 | 0.795006 | Good |
| 20054780 | 0.795006 | Good |
| 20112338 | 0.795006 | Good |
| 20065456 | 0.795006 | Good |
| 20062983 | 0.795006 | Good |

| | | |
|---|---|---|
| 20054775 | 0.795953 | Good |
| 20079218 | 0.797571 | Good |

## 2 - OEB Staff - 43

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 154

Preamble:

EnWin Utilities explains its asset replacement and refurbishment considerations as follows:

ENWIN utilizes a combination of patrols and maintenance activities to complete inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year.

Question:

a) On what basis was the "one-third of each major asset" determined?

b) Please provide the analysis showing that one-third is the optimal cycle frequency for patrol / maintenance.

---

Response:

a) ENWIN adheres to the inspection requirements of Appendix C of the Distribution System Code which requires pole inspections every 3 years for urban areas.
b) ENWIN adopted the requirements of Appendix C of the Distribution System Code and the results of the poles inspections have not indicated the need to deviate from these requirements.

## 2 - OEB Staff - 44

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 155-157

Preamble:

EnWin Utilities provides its asset-specific strategies. Staff summarizes these philosophies in the table below:

| Distribution System Assets | Strategy | Rationale for Strategy |
|---|---|---|
| Pole | "manage[d] … proactively" | "the reliability of [customers' electrical] service depends upon the health of the pole assets" |
| Feeder Cable | "manage[d] … proactively" | "the dependence of ENWIN's customers on their electrical service and … the reliability of that service … upon the health of the cable assets" |
| Subdivision Cable | "manage[d] … proactively" | "Repair and replacement … typically requires a great deal of effort and time" |
| Polyphase Padmount Transformer | "proactive[e] maint[enance] and replace[ment] … to avoid an in-service failure" | "generally used to serve larger commercial customers… [who] are judged to suffer a greater degree of hardship due to loss of power than a residential customer" |
| Submersible Transformer | "proactive[e] maint[enance] and replace[ment] … to avoid an in-service failure" | Long replacement timeframe if failure occurs in winter (frozen in place). |
| Minipad Transformer | "run to failure" | "an in-service failure or a planned replacement will result in nearly the same level of inconvenience for customers" |
| Three-Phase Overhead Transformer | "proactive[e] maint[enance] and replace[ment] … in order to avoid an in-service failure" | "generally used to serve larger commercial customers… [who] are judged to suffer a greater degree of hardship due to loss of power relative to residential or small commercial customers" |
| Single Phase Overhead Transformer | "run to failure" | "an in-service failure or a planned replacement will result in nearly the same level of inconvenience for customers" |
| Padmount Switching Unit | "repair or replace … on a proactive basis" | "in-service failure of a switch when it is being relied upon to isolate and/or connect distribution segments can significantly prolong an outage" |
| Manhole | "regula[r] inspect[ion]… and, where appropriate, remediat[ion]" | "sudden failure of a roadway manhole can result in vehicle damage, cable damage, and life-threatening endangerment of the vehicle driver" |

Question:

a) For each of the distribution system assets, please confirm that the asset strategy and rationale in the table above are correct.

Response:

a) The strategy and rationale in the table above are all correct.

## 2 - OEB Staff - 45

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 155

Preamble:

EnWin Utilities explains its pole sustainment philosophy as below:

The alternatives for maintenance of pole assets are either run-to-failure or proactively maintain the poles to extend their life and replace them prior to failure. Given the dependence of ENWIN's customers on their electrical service and that the reliability of that service depends upon the health of the pole assets, ENWIN chooses to manage the pole infrastructure proactively through its pole sustainment program. ENWIN treats its poles with boron rods mid-life in order to extend the useful life of the pole.

Question:

a) Does EnWin Utilities have a single strategy for all poles, or do poles in low consequence of failure locations (e.g. at the ends of feeders / lightly loaded feeders) have a different strategy than poles in higher consequence of failure locations (e.g. closer to the substation, high utilization feeders)?

Response:

a) All poles are inspected using the same method and their health condition established based on the same criteria but the replacement priority is defined on a project basis using judgment or risk assessment performed with PROSORT. Within the Poles asset category, poles closer to a substation, part of a heavy loaded feeder and or carrying additional feeders or transformers will have higher priority when compared with poles in similar condition at the end of a feeder, lightly loaded feeder or only carrying a single feeder.

## 2 - OEB Staff - 46

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 156

Preamble:

EnWin Utilities explains its three-phase overhead transformer sustainment philosophy as below:

The sustainment alternatives for overhead transformers are to either proactively maintain and replace the transformers, or run them to failure. Three phase overhead transformer banks (and 3-in-1s) are generally used to serve larger commercial customers. Such customers are judged to suffer a greater degree of hardship due to loss of power relative to residential or small commercial customers. Consequently, to best serve these customers, ENWIN proactively maintains and replaces these transformers in order to avoid an in-service failure.

Question:

a) Please define "greater degree of hardship due to loss of power relative to residential or small commercial customers" that warrants a change in strategy from run to failure to a proactive replacement strategy.

b) Please define the combination of consequence of failure (e.g. "increased hardship") and probability of failure that is the threshold for asset replacement.

Response:

a) The "greater degree of hardship due to loss of power relative to residential or small commercial customers" is related to the fact that since three phase overhead transformers are generally used to serve larger commercial customers, the financial impacts of prolonged outages in case of in-service failure is much higher and warranties a proactive replacement strategy.

b) Only transformer banks greater than or equal to 150 kVA are proactively replaced. The remainder are run to failure. Therefore, the larger customers will be proactively changed out while the smaller customers would be run to failure. Projects that are identified are prioritized based on the age of the transformers. A list of projects is created for implementation over a 5 year planning horizon. Year over year requirements would be driven by asset health information derived from inspections as well as moderated to manage labour and capital profiles. This has been prioritized through the PROSORT evaluation system obtaining a CRBF rating of $1,444/rating point and is ranked fourth of 65 capital line items considered for the test year. In terms of the consequence of failure and likelihood of occurrence, the element judged to have the worst outcome for the customer is with regard to customer costs. These were judged to be “Moderate” or between $1,000 and $100,000 with a probability of occurrence within the next 5 years judged “Likely” or will probably occur within the next 5 years as the transformer is judged to be at end of life.

## 2 - OEB Staff - 47

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 165

Preamble:

EnWin Utilities explains its flag for action (FFA) plan as below:

To develop an FFA plan, the risk of removal of each unit must be quantified. Risk is the product of a unit's likelihood of removal and its consequence of failure. An asset unit is FFA when the calculated risk value exceeds a pre-set threshold.

For the asset categories listed below, the risk-based approach is used to estimate the FFA plan.

1. Power transformers (main tank + LTC)

2. Station service transformers

3. Grounding transformers

4. Station breakers

5. Station switches

6. Station batteries

Question:

a) Please provide the "pre-set thresholds" for all the asset categories listed at the reference.

---

Response:

a) The "pre-set thresholds" is a concept that is created by Kinectrics in their Asset Condition Assessment study for transformer station assets as noted above. The note above was taken from page 9 of the Kinectrics report. The "pre-set thresholds" are constants used in Kinectric's proprietary calculation to determine whether or not an asset should or should not be "flagged for action". Two of the constants used as "pre-set thresholds" in the calculation are related to criticality (constant =1.05) of the asset and failure tolerance (constant= 0.8). These constants along with health data are used in the calculation of an effective age for the asset and the age at which the asset would theoretically have an intolerable risk of failure. If the effective age of the asset exceeds the age at which the asset is expected to have an intolerable risk of failure, then the asset is “flagged for action”.

With respect to station assets, ENWIN views these assets as always “flagged for action”. This means that each station is visited by a technologist at least once per month and each station transformer and its ancillary equipment is scheduled for a complete inspection and appropriate maintenance in alternate years.

In the case of ENWIN’s Walker 2 station, at the time of Kinectrics’ review, ENWIN was delayed in completing the manufacturer-recommended 7-year maintenance on the load tap changers due to a contractual issue with the vendor doing the maintenance. This caused that item to be “flagged for action” with a “very poor” rating from Kinectrics. ENWIN was already working to remedy the delay and the maintenance was completed at approximately the same time as Kinectrics completed their study.

## 2 - OEB Staff - 48

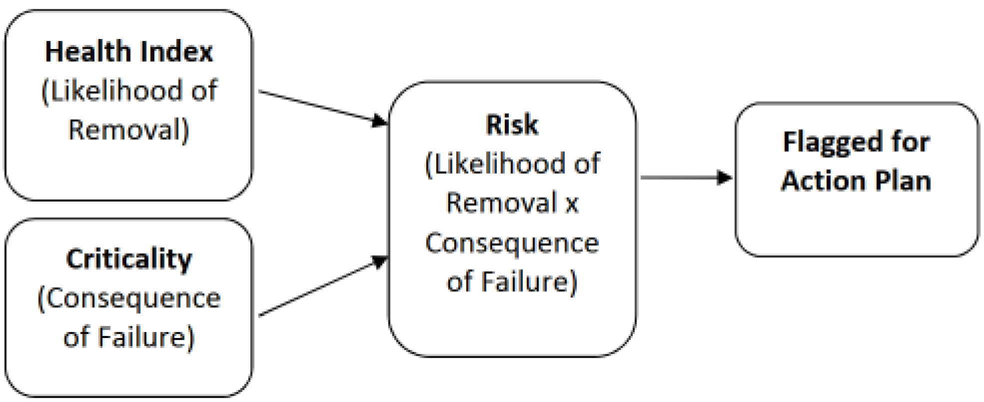
Reference:

Exhibit 2: Rate Base, Attachment 2A, Pages 164-5

Preamble:

At the above noted reference, EnWin Utilities provided Figure 73 for how it is managing asset lifecycle risk:

**Figure 73 Managing Asset Lifecycle Risk**




Question:

a) Does the “consequence of failure” calculation take into account the location of an asset in EnWin Utilities’ system – specifically, whether that asset is located in a redundant/networked area, or on a radial part of the system?

i. If yes, please quantify how much lower the “Criticality” score for an asset would be if it was located in a redundant/networked part of the system, vs. a radial part of the system. Assume an otherwise similar asset.

ii. If no, please explain why the consequence of failure does not account for asset location within the system with respect to redundant/networked or radial functionality.

Response:

a) The consequence of failure does take into account the location of the asset on the distribution system. This is explained and an example is provided in response to OEB Staff-38 (b).

## 2 - OEB Staff - 49

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 182

Exhibit 2: Rate Base, Attachment 2A, Appendix B, Page 8

Preamble:

As seen from Table 68 provided by EnWin Utilities, the customer ranks the price as the first priority in the online and telephone engagement:

**Table 68 Analysis of Customer Engagement**

| Top 3 Customer Priorities | Online | Telephone | |
|---|---|---|---|
| | Residential | Residential | Small Business |
| 1st | Price | Price | Price |
| 2nd | Reliability | Reliability | Reliability |
| 3rd | Safety | Safety | Safety |

In reference to customer satisfaction with current reliability levels, EnWin Utilities' customer engagement study stated:

In terms of delivering reliable service, ENWIN is performing very well. … In the quantitative phase questions were framed to determine satisfaction with various aspects of reliability; number of outages, restoration time, and power quality. All measures show a high degree of satisfaction …

Question:

a) Please confirm that EnWin Utilities' customers have indicated that ENWIN is providing adequate reliability performance, and that ENWIN's first focus should be to contain the price of its service.

b) Please confirm that this DSP proposes significant investments to improve reliability performance, that those investments will cause rates to increase, and therefore the DSP is not responsive to customer desires. If not confirmed, please explain how the DSP responds to the customers' 1st priority.

---

Response:

a) ENWIN is focused on delivering safe and reliable service at an affordable price, and in delivering good value to its customers. ENWIN does not agree with OEB Staff that ENWIN should sacrifice public safety or reduce system reliability in order to focus solely on reduced price. Such an approach would not be consistent with good utility practice. With these objectives in mind, ENWIN strives to construct, operate and maintain the distribution system at a price that is affordable for its customers. Costs are always taken into consideration when designing, building and operating the distribution system.

b) Not confirmed. Investments in System Renewal and System Service categories always have an effect on the reliability of the distribution system as will the absence of those investments. ENWIN's goal is to maintain the degree of reliability to which its customers are accustomed. The level of investment that ENWIN proposes in the DSP is consistent with the level of investment that it has maintained since the last cost of service application in 2009 with increases which account for inflation. ENWIN believes that its DSP is responsive to its customers' desires as it maintains a consistent pattern of investment in its distribution system. The measure of the DSP's responsiveness to customer desires is in how the DSP was adapted to take customer feedback into consideration. See SEC-19 for items removed from the DSP out of consideration for cost reduction.

## 2 - OEB Staff - 50

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 184

Preamble:

EnWin Utilities states the following:

System Renewal investments are needed to proactively replace aging infrastructure. The customer engagement feedback was:

"When it comes to replacing aging infrastructure, respondents are divided with a slight lean in favour of investing what it takes to maintain system reliability; even if this increases customer monthly bills."

Question:

a) Please quantify "slight lean" as a percentage of respondents.

b) Does the above statement imply that nearly half of customers (i.e. the group not included in the "slight lean") would be willing to have reliability decrease if it saves them money?

i. If yes, how has EnWin Utilities considered that customer feedback in the development of its capital spending plan?

ii. If no, how should the statement instead be interpreted?

---

Response:

a) Per the Innovative Research comment regarding the "slight lean", Innovative provided the following quantification of the statement.

| Telephone Survey Respondents | Residential | Small Business (<50kW) |
|---|---|---|
| **Addressing the *Frequency* of unexpected power interruptions** | | |
| Spend what is needed to **reduce** # of power outages | 23% | 25% |
| Spend what is needed to **maintain** current levels | 51% | 49% |
| **Accept more power outages** in order to help costs from rising | 14% | 14% |
| **Addressing the *Length* of unexpected power interruptions** | | |
| Spend what is needed to **reduce** length of power outages | 25% | 23% |
| Spend what is needed to **maintain** current levels | 47% | 50% |
| **Accept longer power outages** in order to help costs from rising | 19% | 17% |

Majority of low-volume customers want EnWin to spend what is needed to either *maintain* or *improve* reliability

This is taken from page 10 of Appendix B – Customer Engagement in the DSP.

b) The statement made by Innovative Research indicates that approximately 72-74% of customers surveyed would like ENWIN to spend what is needed to maintain or improve system reliability while 14-19% would accept more/longer power outages.

## 2 - OEB Staff - 51

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 184

Preamble:

EnWin Utilities states the following:

This shows that ENWIN needs to be aware of the price its customers are paying. This principle is captured in ENWIN's tagline—"to deliver electricity at a reasonable price". However, the tradeoff is clear in the customers' mind as, "Customers expect ENWIN to maintain a proactive capital investment program that either improves or maintains system reliability." ENWIN has been proactive in system enhancement investments to meet this expectation. These projects include: Sectionalizing Load Break Switches, Underground Switching Units, Feeder Ties and other similar projects.

Question:

a) Please provide evidence demonstrating that the cited "tradeoff is clear in the customers' mind".

b) Please provide evidence demonstrating that customers have indicated they want EnWin Utilities to "maintain a proactive capital investment program that ... improves ... reliability".

---

Response:

a) Reference is made to question 2-OEB Staff-50.

| Telephone Survey Respondents | Residential | Small Business (<50kW) |
|---|---|---|
| Addressing the *Frequency* of unexpected power interruptions | | |
| Spend what is needed to **reduce** # of power outages | 23% | 25% |
| Spend what is needed to **maintain** current levels | 51% | 49% |
| **Accept more power outages** in order to help costs from rising | 14% | 14% |
| Addressing the *Length* of unexpected power interruptions | | |
| Spend what is needed to **reduce** length of power outages | 25% | 23% |
| Spend what is needed to **maintain** current levels | 47% | 50% |
| **Accept longer power outages** in order to help costs from rising | 19% | 17% |

Majority of low-volume customers want EnWin to spend what is needed to either *maintain* or *improve* reliability

When Innovative was developing their questions for the survey ENWIN encouraged them to put the questions in a way that customers would clearly communicate their priorities, needs and preferences by choosing between alternatives that were tradeoffs. The questions that were put to customers did this. In the questions in the table, it is clear that customers were asked to choose between spending a little more to improve reliability, spending what is necessary to maintain current reliability or accepting more frequent and longer outages to help keep rates from rising. By asking the questions in this manner, ENWIN feels that the tradeoff is clear in the customer's minds. As well, in focus groups, time was spent explaining to customers that there is a tradeoff between safety & reliability and cost.

b) The excerpt from the customer engagement by Innovative that is provided here is clear that some customers want ENWIN to maintain a proactive capital investment program.

## 2 - OEB Staff - 52

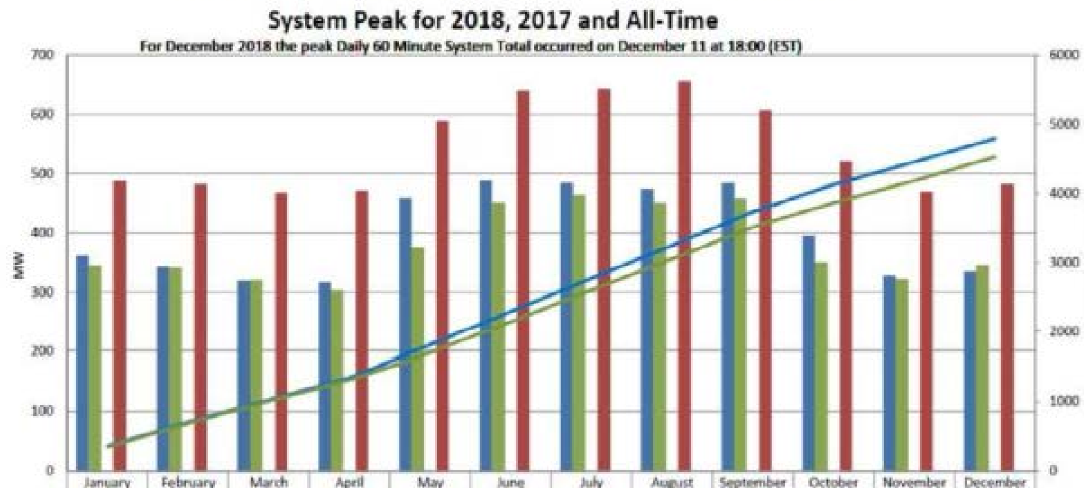
Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 192

Preamble:

EnWin Utilities provides Figure 79 for system peak for 2018, 2017 and all-time:

**Figure 79 System Peak for 2018, 2017 and All-Time**




| | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 362 | 342.8 | 319.7 | 316.7 | 458.6 | 488.9 | 484.6 | 474.1 | 484 | 395.3 | 328 | 335.2 |
| 2017 | 345.1 | 341.5 | 320.8 | 303.4 | 376.1 | 450.8 | 464.2 | 450.4 | 458.2 | 350.2 | 322.8 | 345.8 |
| Percentage Change | 4.9% | 0.4% | -0.3% | 4.4% | 21.9% | 8.5% | 4.4% | 5.3% | 5.6% | 12.9% | 1.6% | -3.1% |
| All Time Monthly Peak | 488.5 | 482.2 | 468.1 | 471.4 | 589.3 | 640.2 | 643.5 | 656.7 | 607.1 | 521.2 | 469.8 | 482.2 |
| Year | 2004 | 2004 | 2002 | 2002 | 2006 | 2005 | 2006 | 2006 | 2002 | 2005 | 2000 | 2003 |
| 2018 MW YTD | 362.0 | 704.8 | 1,024.5 | 1,341.2 | 1,799.8 | 2,288.7 | 2,773.3 | 3,247.4 | 3,731.4 | 4,126.7 | 4,454.7 | 4,789.9 |
| 2017 MW YTD | 345.1 | 686.6 | 1,007.4 | 1,310.8 | 1,686.9 | 2,137.7 | 2,601.9 | 3,052.3 | 3,510.5 | 3,860.7 | 4,183.5 | 4,529.3 |

Figure 79 above shows the system peak for 2018, 2017 and all-time.

While the present growth is low or minimal, EnWin Utilities' distribution area has potential for future development. These areas may not see load growth in the near term, but eventually these loads will appear at the existing TSs, and ENWIN will have to serve those customers. EnWin Utilities studied the City land allocation maps as published by the City planning department.

Question:

a) What does cumulative MW mean as that parameter is used in Figure 79? It appears to be a simple sum of the peak load reached in each month with the peaks reached in prior months. What is the purpose of this parameter?

b) Please confirm that EnWin Utilities is not proposing to make speculative capital investments to serve potential future loads in the identified future development areas.

Response:

a) "Cumulative MW" as it applies to Figure 79 refers to the line portion of the graph and is the sum, by month, of the monthly peaks. ENWIN's purpose for the graph is to show a visual year to date and year-over-year trend in the system peaks and their variation.
b) ENWIN confirms that it does not make speculative capital investments to serve potential future loads. ENWIN only builds out its distribution system when it has an application and a signed contract for service from new customers.

## 2 - OEB Staff - 53

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 195

Preamble:

EnWin Utilities explains the impacts on the customers of its grid modernization program as below:

(c) Grid Modernization

ENWIN upgraded its old 4 kV distribution system to a 27.6 kV system (as discussed in Section 5.2.1 (h) of the DSP). This upgrade increased the number of customers on a feeder, which resulted in worse reliability despite the newer infrastructure, as it increased the number of customers that are affected by a single event. As a result, ENWIN developed a longer term grid modernization plan to remediate the current reliability issues and to lay the groundwork to address future challenges with DER, and possible climate change consequences.

Question:

a) Please quantify the deterioration in reliability attributable to implementing the voltage upgrade program.

i. Is the level of reliability deterioration material?

ii. Has EnWin Utilities received independent corroboration from customers that they perceive the impact as material? If yes, please provide evidence.

b) Was this reliability deterioration anticipated when the voltage upgrade program was planned?

i. If yes, was the need for (and cost of) the related reliability enhancement projects understood to be part of the upgrade project?

ii. If no, why not?

Response:

a) ENWIN began building new electrical distribution infrastructure with a 27.6 kV design in the early 1970's. By the early 2000's most of the 4 kV infrastructure was at or approaching end of life. Prior to that, there was some ad hoc replacement of the end-of-life 4 kV infrastructure with 27.6 kV infrastructure. In 2004, the replacement of 4 kV infrastructure with 27.6 kV infrastructure was formalized in a report which received approval from ENWIN's Board of Directors. The report outlined a progressive plan to rebuild end of life 4 kV plant with 27.6 kV plant.

The reliability characteristics of the 4 kV infrastructure were not determined separately from the characteristics of the 27.6 kV infrastructure. However, the 4 kV infrastructure was more likely to be at end of life than the 27.6 kV infrastructure but had fewer customers appended to a protective device so that fewer customers were interrupted during a fault event. Older records show that there were 132-4 kV feeders in service in the early 1990's. In 2004, a report was written that formalized the conversion of the 4 kV system through end-of-life replacement with the 27.6 kV system. The 2004 voltage conversion report shows that at time of the 2004 recommendation, there were 69 kV feeders remaining. A 2008 update on progress shows that there were 31 4 kV feeders remaining with each feeder serving an average of 200 customer with the number of customers per feeder typically in the 50 – 500 range. Thus, in the early 1990's the distribution system had approximately 175 protective devices and with the elimination of those protective devices on the 4 kV system, the distribution system would now have just over 40 protective devices.

While separate reliability statistics were not determined for 4 kV and 27.6 kV systems it is a reasonable conclusion that the reliability of a system with 175 protective devices would be better than a system with 40 protective devices. Confounding the comparison is that the 4 kV system was at end of life and the 27.6 kV system was newer so the 4 kV system could be expected to have more equipment failure incidents than the 27.6 kV system. As well, the 27.6 kV feeders were longer and had a larger footprint and a higher likelihood of an incident than their 4 kV counterparts.

ENWIN's reliability statistics do not go back before the mid-1990's and for the aforementioned reasons, a comparison is not available. Thus, the materiality of the difference in reliability for ENWIN's 4 kV and 27.6 kV systems is not determinable. As well, ENWIN's customers would not be able to provide an opinion regarding the difference in reliability for this reason as well as that the change in systems took place over many years and as such, the difference in reliability would likely have not been noticed by ENWIN's customers.

b) The difference in reliability did not appear to have been considered when the rebuild of the 4 kV system was started prior to 1990. Regardless, the decision to rebuild the system to a 27.6 kV standard had sufficient compelling reasons to proceed. It is not known why the staff at the time did not consider this and all of those involved in the decision are no longer with the company. Nevertheless, when the 4 kV program was formalized in 2004, there was a recognition in the capital budget of the time that reclosers were needed to replace some of the functionality of the protective devices lost through the earlier conversion of 4 kV systems to 27.6 kV systems. The 2004 budget included additional protective devices in the form of $380,000 for ENWIN’s first 3-phase reclosers.

## 2 - OEB Staff - 54

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 195

Preamble:

EnWin Utilities explained the conductor upgrades project as below:

ENWIN has identified the need for a number of conductor upgrade projects. This work was initiated due to previous design standards which utilized a single-ended radial feed concept. Since radial feeders were not expected to connect to other feeders nor support the loads of other feeders, the conductor size was often reduced to a size needed to just support the feeder end load. Consequently, the conductor capacities of feeders vary along the main feeder trunk. There are many cases where the end of the old feeders were built with 4/0 or 336 MCM conductors (normal conductor size is 556 MCM). Today, these feeders are expected to carry a full additional feeder section, which means the conductors used at feeder ends are undersized.

Question:

a) Please provide the consequence of failure ratings for the conductor, towers, breakers, transformers etc. before and after the single end-radial feeder conductor replacement project is completed.

b) Please provide the risk reduction and project cost for a typical single-ended radial feeder conductor replacement project. Please show the before and after probability and consequence of failure, and before and after total risk calculation.

c) Was the migration from a radial to a backup-capable configuration philosophy wholly or partly driven by the Grid Modernization voltage upgrade discussed earlier on page 195? Please explain.

Response:

a) The consequence of failure ratings for the conductor, towers, breakers, transformers etc. before and after the single end-radial feeder conductor replacement project is completed is not relevant for a conductor upgrade project. The risk to be mitigated is that when the line section is called upon to support an adjacent feeder load, it cannot, and the consequence is that customers that would have otherwise had their power restored during an outage will remain without power until their primary feeder is restored.

b) The table below summarizes the results obtained by the PROSORT project evaluation system for a typical conductor upgrade project.

| Assessment of Impact of Investment to Business Values | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| RISKS | | | | | | | | | | |
| Business Values | | BEFORE | | | | AFTER | | | | |
| | | Consequence | Likelihood | Score | TRS | Conseque | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | | | | | | | | | NO SAFETY ISSUES IDENTIFIED |
| 0.25 | Reliability | Moderate | Unlikely | 17 | 4.25 | Minor | Rare | 3 | 0.75 | FEEDER UNABLE TO SUPPORT FULL |
| 0.25 | Financial | Moderate | Unlikely | 17 | 4.25 | Minor | Rare | 3 | 0.75 | CUSTOMER COSTS $1K TO $100K |
| 0.2 | Sustainability | Insignificant | Possible | 5 | 1 | Insignificant | Rare | 1 | 0.2 | NO SIGNIFICANT SUSTAINABILITY ISSUES |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| Total Risk Score | | | | | 9.5 | | | | 1.7 | |
| Change in RISK Score (decrease) | | 7.8 | | | | | | | | |
| BENTFITS | | | | | | | | | | |
| Business Values | | BEFORE | | | | AFTER | | | | |
| | | Consequence | Likelihood | Score | TRS | Conseque | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | | | | | | | | | |
| 0.25 | Reliability | | | | | | | | | |
| 0.25 | Financial | | | | | Insignificant | Possible | 5 | 1.25 | IMPROVE FLEXIBILITY OF OPERATIONS |
| 0.2 | Sustainability | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| Total Benefit Score | | | | | | | | | 1.25 | |
| Change in BENEFIT Score (increase) | | 1.25 | | | | | | | | |
| Change in Total RISK-BENEFIT SCORE | | 9.1 | | | | | | | | |
| CRBF ($ / Weighted Score) | | 20,013 | | | | | | | | |

The assessment of the impact of investment for this project resulted in a change in total risk-benefit score of 9.1.

c) The migration from a radial to a backup-capable configuration philosophy is somewhat related to the Grid Modernization voltage upgrade discussed on page 195. The intention is to reduce the number of customers affected by an operation of a protective device (i.e. breaker) by breaking the feeders into smaller sections and then bringing the sections that are not directly affected by the fault back to service. To do this, adjacent feeders must be capable of carrying the additional load from the unaffected sections of the companion feeder. Where the feeder ampacity is not sufficient to carry this additional load, a conductor upgrade is undertaken to enable that functionality.

## 2 - OEB Staff - 55

Reference:

Exhibit 2: Rate Base, Attachment 2A, Pages 196-7

Preamble:

EnWin Utilities states the following:

Feeder Reliability Improvement Projects:

Reliability is the main driver of this project.

ENWIN is planning to maintain the distribution infrastructure for an “N-1” full station contingency. Such contingencies have occurred in other place in the Province, such as the recent tornado in the Ottawa Merivale TS, or the fire at the HONI’s Finch TS in Toronto. These are considered long-term contingencies, meaning that the time to effect restoration after the contingency is in the order of weeks to months. Based on the reasonable risk of a complete loss of a supply station, ENWIN developed a long-term plan to build high capacity power transfer corridors between stations that will be constructed in coordination with ENWIN’s EOL replacement pole projects and City infrastructure re-development projects.

…

Radial Branch Backups:

ENWIN will complete all radial feed removals with large customer pockets (>500 customers) during its present planning cycle. This helps to increase the reliability of the system, and the supply reliability to the customers.

Question:

a) Please quantify "reasonable risk"? Is this equivalent to the probability of supply station loss?

b) What is the annual probability of complete loss of Keith TS, Malden TS and Crawford TS? Please explain how the probabilities were derived and list the assumptions made when deriving them.

c) Please provide the before and after risk evaluations and the associated project cost for each of the remaining planned radial feed removals.

Response:

a) The consequence of the risk of an extended station outage is the inability to provide electricity to customers for an extended duration, potentially causing negative impacts to customer's lives and property damage to customers. The likelihood of such a risk is that it is indeed possible to occur as happened in Ottawa and Toronto. In fact, the path of the tornado that hit Windsor in 2016 was only 650m from the Essex TS, the Walker 1 and the Walker 2 TS'. These 3 TS' are in close proximity to one another with Walker 1 and 2 sharing a station fence and are sourced from the same high voltage supply. ENWIN's statement regarding "reasonable risk" was intended to convey that it is reasonable to consider the loss of a station as that has indeed occurred recently to other Ontario LDCs.

b) The annual probability of complete loss of Keith TS, Malden TS and Crawford TS is judged the same as for the other stations serving ENWIN load. ENWIN used historical data to determine the probability of station outages. The following table shows total station outages recoded in all distribution transformer stations since 2004. There were other station incidents where one of the two transformers were removed from service however the incidents below are where both transformers were removed.

| Station Total Outages since 2004 | | | |
|---|---|---|---|
| **Station** | **Date** | **Cause** | **Time (hours)** |
| Crawford TS | 07-Sep-04 | Animal Contact, remove both T/F from service | 0.27 |
| Essex TS | 15-May-05 | Animal Contact , remove both T/F from service | 0.08 |
| Malden TS | 24-May-12 | Cable fault , remove both T/F from service | 0.08 |
| Essex TS | 20-Feb-13 | Essex ring bus fault, remove supply to both T/F. | 0.97 |
| Keith TS | 29-Apr-16 | Animal contact at Keith T23 transformer (230kV/28kV) caused 230kV differential trip at Keith TS. By protective design T22 was removed from service causing total loss of 28kV load at Keith TS. | 1.07 |
| Lauzon TS | 26-Aug-16 | Lauzon TS was on single 230kV feed due to Hydro One work on C24Z. By configuration, Lauzon T5 transformer was the single source for ENWIN's Lauzon load. The Lauzon T5 transformer tripped on differential protection caused by defective 28kV connection at T5 transformer. | 0.68 |
| Lauzon TS | 06-Sep-16 | Lauzon TS was on single 230kV feed due to Hydro One work on C23Z. H1 crew accidentally contacted energized C24Z in Lauzon TS yard with hold off in effect causing it to trip, de-energizing all C24Z load between Chatham and Windsor. | 0.82 |
| Keith TS | 07-Sep-18 | Keith TS was on single 230kV feed due to Hydro One work on the T23 transformer. The remaining transformer lost its source when the C22J circuit tripped open, the C22J was reclosed 3 minutes later. No cause for the 230kV trip was found. | 0.05 |
| Crawford TS | 09-May-19 | Crawford TS lost power when the J3E and J4E circuits tripped out of service due to structure fire at Gordie Howe Bridge construction site. All load transferred off Crawford TS. | 0.98 |

ENWIN experienced 9 total station failures between 2004 and 2019; fortunately none of those events were catastrophic. Based on the statistics, ENWIN can expect one total station failure every 1.8 years (16 Years /9 Events) or 0.56 events per year. This is what informs ENWIN regarding its probability of failure. However, in the 8 years since 2012, there have been 7 incidents or 1.1 years between incidents. This increased level of incidents is attributed to the fact that Hydro One has been working on their lines and stations in many of those years as it upgrades its aging infrastructure and when work is occurring, there is an increased likelihood of an incident. This is in part due to the fact that high voltage supply to the stations is often on a single supply rather than a redundant supply, making the station vulnerable to single contingencies.

c) The radial feed risk before and after mitigation is the same as provided for 2020 projects. Individual radial feed projects differ only by cost, which affects the PROSORT rank and the priority of each project. Please see Appendix F – Material Investment Summaries: Radial Branch Backups of the DSP.

## 2 - OEB Staff - 56

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 4

Exhibit 2: Rate Base, Attachment 2A, Pages 204-206

Preamble:

EnWin Utilities provides Table 1, which shows a step increase in capital spending from pre-2019 to post-2019:

**Table 1 Historical and forecast capital expenditures and system O&M**

| Category | Historical ($ '000) | | | | | Forecast ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| System Access | $ 2,762 | $ 3,946 | $ 3,963 | $ 3,310 | $ 7,267 | $ 6,205 | $ 3,476 | $ 3,526 | $ 3,577 | $ 3,628 |
| System Renewal | $ 8,221 | $ 5,475 | $ 5,456 | $ 5,586 | $ 7,289 | $ 8,440 | $ 8,009 | $ 7,605 | $ 7,850 | $ 7,366 |
| System Service | $ 6,433 | $ 2,931 | $ 3,976 | $ 4,427 | $ 4,221 | $ 3,537 | $ 3,622 | $ 3,610 | $ 3,986 | $ 3,623 |
| General Plant | $ 3,499 | $ 2,253 | $ 2,058 | $ 3,098 | $ 7,507 | $ 5,021 | $ 4,283 | $ 3,856 | $ 4,174 | $ 4,213 |
| Total (Gross) | $ 20,915 | $ 14,605 | $ 15,452 | $ 16,421 | $ 26,284 | $ 23,203 | $ 19,390 | $ 18,597 | $ 19,587 | $ 18,830 |
| Contributed Capital | $ 4,322 | $ 412 | $ 2,217 | $ 1,889 | $ 4,898 | $ 3,252 | $ 813 | $ 823 | $ 834 | $ 844 |
| Total (Net) | $ 16,592 | $ 14,194 | $ 13,236 | $ 14,532 | $ 21,386 | $ 19,951 | $ 18,577 | $ 17,774 | $ 18,753 | $ 17,986 |
| System O&M | $ 4,398 | $ 4,631 | $ 9,757 | $ 9,825 | $ 10,942 | $ 10,904 | $ 11,049 | $ 11,068 | $ 11,102 | $ 11,096 |

EnWin Utilities identifies corporate risks that it is facing:

**5. Management Retirements, Knowledge Gap** … Like other utilities, ENWIN is experiencing high levels of retirements of senior personnel in both managerial and field staff ranks.

**6. Field Retirements, Knowledge Gap** … Similar to the issue with management staff, ENWIN is dealing with retirement of experienced field staff.

…

**9. Workforce Overloaded-Quality Impacted/Number and complexity of projects is exceeding the organization's ability to deliver on them.** … ENWIN has reduced its staff complement over the years since the last CoS, but demands on ENWIN have continued to increase. To mitigate the risk that the quality of work may suffer because of the increased demands on staff, ENWIN has adopted a formal project management framework to be used for all substantial projects. This framework helps to ensure that projects are formally planned, resources identified, milestone timeframes set and reporting identified and executed.

Question:

a) What is the threshold for "substantial" project?

b) What % of projects by both number and dollar value are classified as "substantial" vs. not "substantial"?

c) Does EnWin Utilities consider it to be good utility practice to not have a formal project management framework for projects assessed as being not "substantial"?

i. How does EnWin Utilities ensure project execution effectiveness for non-substantial projects in the absence of a "formal project management framework"?

d) Given the retirements of experienced staff and associated loss of organizational capacity and knowledge, please describe why the lack of formal PM framework doesn't put ratepayers at cost risk due to potential cost overruns and/or reduced execution productivity?

e) Given the proposed increase in capital spending vs. pre-2019 levels, how does EnWin Utilities propose to compensate for the reduced staff complement and ongoing field and management retirements?

---

Response:

a) ENWIN has three tiers of corporate projects (Tier 1, Tier 2 and Support). Tier 1 Projects are large projects spanning greater than 6 months or greater than $100k investment. They are typically linked to a corporate strategic deliverable. Tier 2 Projects are medium projects spanning at least 3 months or up to $100k investment. They are typically supporting a portion of a corporate strategic deliverable. Support projects are smaller projects that are contained to one department. Therefore both Tier 1 and Tier 2 are considered substantial projects with thresholds as shown.

b) Please see the below chart:

| **Project Type** | **By Number (%)** | **By Dollar Value (%)** |
|---|---|---|
| Substantial (Tier 1, 2) | 65% | 100% |
| Non-Substantial (Support) | 35% | 0% |

Note: Non-substantial (Support) project costs are much smaller and use internal labour costs in most cases which is why when rounded off 0% by dollar value is shown.

c) The Non-Substantial (Support) projects are still reported monthly to the organization and tracked by the Project Management Office. Visibility to budget, schedule, scope, resources and overall project is tracked and made visible so that any issues can be addressed in a timely manner. Therefore even though a formal framework is not applied by a Project Manager, tracking and reporting of updates and status does follow the formal project management practice at ENWIN. In addition to this, ENWIN tracks Hydro Capital Projects using a proprietary software called “ProjExec” to monitor and report on costs by project on a weekly basis.

i) As stated above, through monthly tracking of status (red, yellow, green), detailed monthly updates and visibility to the organization for all corporate projects, including non-substantial ones, as well as Hydro Capital Project using ProjExec, ENWIN ensures all projects are executed effectively.

d) There is no risk to the ratepayers as the costs and execution productivity are tracked at both the corporate level monthly and the Hydro Capital crew level weekly. This ensures there is enough granularity for all projects to react appropriately and get the project back on track if there are any risks or warning signs that the project might be at risk for any reason.

e) ENWIN plans to compensate for the retirements by continuing to look at innovation, process improvements and technology opportunities where they might exist. For example, in 2018 ENWIN launched the ENnovation Catalyst program where staff at all levels can work with innovation experts to find solutions to problems they are facing and identify and implement continuous improvement initiatives if they desire. The ENnovation Catalyst program is in its second year, 2019, and continues to bring forth problems, ideas and solutions from all levels and areas of the organization. ENWIN continues to streamline the process that the Project Management Office reports on projects to the organization to make sure key information is easy to read and understood by all stakeholders. As for technology, the IT department continues to find new tools and opportunities for employees to work more effectively, such as the SAP Fiori App that allows for work order, purchase requisition and time approvals from mobile devices.

## 2 - OEB Staff - 57

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 272

Preamble:

EnWin Utilities provided Table 132 for 2018 forecast and 2019 bridge system renewal expenditures:

**Table 132 2018 Forecast and 2019 Bridge System Renewal Expenditures**

| Expenditure Category | 2018 Forecast | 2019 Bridge | Difference |
|---|---|---|---|
| 4 kV Conversion | $0 | $0 | $0 |
| 27.6 kV Pole Replacements | $2,200,000 | $2,950,000 | $750,000 |
| Planned Cable Replacements | $215,077 | $120,000 | -$95,077 |
| Planned & Reactive Transformers | $1,265,000 | $1,350,000 | $85,000 |
| Reactive Pole Replacements | $150,000 | $100,000 | -$50,000 |
| Reactive Equipment Replacements | $115,218 | $280,000 | $164,782 |
| Reactive Conductor Replacements | $30,000 | $90,000 | $60,000 |
| Manhole Rebuilds | $160,000 | $150,000 | -$10,000 |
| Switching Units | $340,000 | $825,000 | $485,000 |
| Station Equipment | $2,658 | $0 | -$2,658 |
| Other/ (Pole Inspection) | $1,108,250 | $1,424,000 | $315,750 |
| Total | $5,586,203 | $7,289,000 | $1,702,797 |

System Renewal expenditures are increased in 2019 by approximately $1.7 million. An increase in pole replacement budget of $750k was made to bring the pole replacement budget closer to the values indicated in the ACA, which was done in 2017.

Question:

a) Please update the 2018 figures using the 2018 actuals and explain the variances if the 2018 actuals are +/-10% different than the 2018 forecast.

Response:

Actual System Renewal expenditures for 2018 exceeded the forecast by $766,332. Therefore, the increase from 2018 Actuals to 2019 Bridge is reduced to $936,465 (from $1.7 million). As indicated, the majority of this increase is to the Pole Sustainment program in accordance with the ACA. Please see the table below which compares 2018 Forecast to 2018 Actual for System Renewal expenditures with explanations for variances +/-10%.

| Projects | 2018 Forecast | 2018 Actuals | Variance | Variance % | Explanation |
|---|---|---|---|---|---|
| **Reporting Basis** | **MIFRS** | **MIFRS** | | | |
| 4 kV Conversion | $ - | $ - | $ - | - | |
| 27.6 kV Pole replacements | $ 2,200,000 | $ 2,151,326 | -$48,674 | -2.21% | |
| Planned cable replacements | $ 215,077 | $ 84,444 | -$130,633 | -60.74% | UG Cable Sustainment (Subdivision) program was behind schedule. Excess funds were re-assigned to the UG Submersible Transformer Sustaining program. |
| Planned & reactive transformers | $ 1,265,000 | $ 1,744,654 | $479,654 | 37.92% | Higher than planned spend on UG Padmount Sustaining and Submersible Sustaining programs due to increased scope and complexity of projects. |
| Reactive pole replacements | $ 150,000 | $ 245,388 | $95,388 | 63.59% | Broken or abandoned poles were replaced/removed as necessary. Additional funds were reallocated from the Pole Sustaining program. |
| Reactive equipment replacements | $ 115,218 | $ 223,584 | $108,366 | 94.05% | Reactive spend on equipment replacements in line with original budget. |
| Reactive conductor replacements | $ 30,000 | $ 78,010 | $48,010 | 160.03% | Reactive spend on conductor replacements in line with original budget. |
| Manhole rebuilds | $ 160,000 | $ 184,313 | $24,313 | 15.20% | Slightly higher than planned spend due to unforeseen field conditions. Additional funds were reallocated from Reactive Manhole program. |
| Switching units | $ 340,000 | $ 548,634 | $208,634 | 61.36% | Higher than forecast spend on Switching Unit Sustaining program due to increase in material costs (switching units themselves). |
| Station equipment | $ 2,658 | $ 2,658 | $0 | 0.00% | |
| Other renewal | $ 1,108,250 | $ 1,089,524 | -$18,726 | -1.69% | |
| **Sub-Total** | **$ 5,586,203** | **$ 6,352,535** | **$766,332** | **13.72%** | |

## 2 - OEB Staff - 58

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 284

Preamble:

Regarding its historical levels and forecast levels of system renewal expenditures, EnWin Utilities provides Table 144 and states:

**Table 144 ENWIN's Investments in System Renewal**

**System Renewal Expenditures - Actual**

| Year | Amount |
|---|---|
| 2009 | $ 7,848,312 |
| 2010 | $ 6,921,307 |
| 2011 | $ 8,132,941 |
| 2012 | $ 7,569,208 |
| 2013 | $ 8,126,349 |
| 2014 | $ 6,951,993 |
| 2015 | $ 8,221,104 |
| 2016 | $ 5,474,883 |
| 2017 | $ 5,455,688 |
| Average | $ 7,211,804 |

**System Renewal Expenditures - Prospective**

| Year | Amount |
|---|---|
| 2018 | $ 5,586,000 |
| 2019 | $ 7,289,000 |
| 2020 | $ 8,440,000 |
| 2021 | $ 8,009,000 |
| 2022 | $ 7,605,000 |
| 2023 | $ 7,850,000 |
| 2024 | $ 7,366,000 |
| Average | $ 7,449,000 |

As can be seen in Table 144 above, EnWin Utilities' investment in System Renewal has been relatively consistent year over year, and is projected to remain so through the DSP prospective period.

Question:

a) Table 144 shows inter-annual System Renewal spending increases of +30% from 2018 to 2019, and +15% from 2019 to 2020. Is EnWin Utilities' position that these inter-annual variations represent investments that are "relatively consistent from year to year"?

i. If yes, what is the threshold of inter-annual spending increase that would be considered outside the bounds of "relatively consistent from year to year"?

ii. If not, please explain the rationale of the increased expenditures in 2019 and 2020 and gradually decreased expenditures in 2021 to 2024.

Response:

a) Please see the response to OEB Staff – 15.

## 2 - OEB Staff - 59

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 286

Preamble:

EnWin Utilities provides Table 145 for system renewal expenditures for 2020:

**Table 145 System Renewal Expenditures for the 2020 Test Year**

| Asset Renewal Type | 2020 Investment Amount ($'000) |
|---|---|
| Poles | $3,300 |
| Metering Equipment | $294 |
| Reactive (poles, cable, etc.) | $470 |
| Transformers | $1,325 |
| Manholes | $150 |
| Switches | $1,025 |
| Cable | $512 |
| Walker Road Pole Replacement | $750 |
| Customer Vault Relocations | $400 |
| Other Miscellaneous | $214 |
| Total | $8,440 |

Question:

a) Please provide a table showing historical and forecast annual pole replacement spending from 2009 to 2024.

b) How many poles have been replaced on average over each of the historical years under the Reactive (poles, cable, etc.) Program? Please provide a table.

c) Are the poles scheduled for replacement under the Walker Road Pole Replacement project considered in EnWin Utilities' evaluation of its forecast pole demographics changes?

d) What is EnWin Utilities' average unit cost ($ per pole replaced) from 2005 to 2018? Please indicate the currency year(s) used in responding.

e) What is EnWin Utilities' forecast average unit cost ($ per pole replaced) from 2019 to 2024? Please indicate the currency year(s) used in responding.

Response:

a) Please refer to OEB Staff – 24.

b) The table below shows the number of poles replaced on a reactive basis since 2015, and have been manually extracted from ENWIN's records. ENWIN does not have records of poles replaced on a planned basis versus reactive basis prior to 2015.

| | 2010 Actual | 2011 Actual | 2011 Actual | 2012 Actual | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | 2017 Actual | 2018 Actual | 2019 Bridge Year | 2020 Test Year | 2021 Forecast Year | 2022 Forecast Year | 2023 Forecast Year | 2024 Forecast Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| # of Poles Reactive Basis | N/A | N/A | N/A | N/A | N/A | N/A | 13 | 14 | 41 | 32 | 16 | N/A | N/A | N/A | N/A | N/A |

c) The poles scheduled for replacement under the Walker Road project were not in the forecast for pole replacements. However, those poles are old and would need replacement either through the eventual widening of Walker Road or through an end of life determination.

d) As per question OEB Staff-24, ENWIN is unable to separate expenditures and pole counts for pole placements by cause (i.e. new, replacement, 27.6 kV, 4 kV, reactive), and consequently, an average cost for replacing a pole developed by available numbers would not be informative. Additionally, the cost per pole replaced will vary significantly depending on what type of services and pole are involved (i.e. wood vs concrete, transformer attachments, number of circuits, secondary, etc.). However, ENWIN reviewed three 2018 pole replacement work orders which indicated an average cost per wood pole replaced of $6,344.

e) ENWIN has forecasted using an estimated average unit cost per pole replaced of $6,100 for 2019 and $6,250 for 2020 to 2024.

## 2 - OEB Staff - 60

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 288

Preamble:

EnWin Utilities states the following:

Similarly, ENWIN's system planning efforts identified that the ENWIN distribution system is, unable to supply all load on a peak day with a loss of supply of the Lauzon station. While HONI, DESN stations are constructed for redundancy, whole stations outages have occurred as, happened to the Lauzon station twice in 2017, and Malden TS and Keith TS in 2018., Additionally, HONI lost a large TS in Toronto due to fire and a station in Ottawa due to a, tornado in 2018. Thus, there is a very realizable risk of such occurrences. ENWIN judges that, extended periods of repeated interruptions due to loss of a station would be unacceptable to, ENWIN's customers.

Question:

a) What were the direct causes of the whole station outages at Lauzon TS, Malden TS and Keith TS?

b) What was the duration of each outage?

c) Does EnWin Utilities know if any steps have been taken by Hydro One to mitigate the probability of future whole station outages at these TS locations?

Response:

a) Total Station outages and cause for the outage are listed below.

| Station Total Outages since 2004 | | | |
|---|---|---|---|
| **Station** | **Date** | **Cause** | **Time (hours)** |
| Crawford TS | 07-Sep-04 | Animal Contact, remove both T/F from service | 0.27 |
| Essex TS | 15-May-05 | Animal Contact , remove both T/F from service | 0.08 |
| Malden TS | 24-May-12 | Cable fault , remove both T/F from service | 0.08 |
| Essex TS | 20-Feb-13 | Essex ring bus fault, remove supply to both T/F. | 0.97 |
| Keith TS | 29-Apr-16 | Animal contact at Keith T23 transformer (230kV/28kV) caused 230kV differential trip at Keith TS. By protective design T22 was removed from service causing total loss of 28kV load at Keith TS. | 1.07 |
| Lauzon TS | 26-Aug-16 | Lauzon TS was on single 230kV feed due to Hydro One work on C24Z. By configuration, Lauzon T5 transformer was the single source for ENWIN's Lauzon load. The Lauzon T5 transformer tripped on differential protection caused by defective 28kV connection at T5 transformer. | 0.68 |
| Lauzon TS | 06-Sep-16 | Lauzon TS was on single 230kV feed due to Hydro One work on C23Z. H1 crew accidentally contacted energized C24Z in Lauzon TS yard with hold off in effect causing it to trip, de-energizing all C24Z load between Chatham and Windsor. | 0.82 |
| Keith TS | 07-Sep-18 | Keith TS was on single 230kV feed due to Hydro One work on the T23 transformer. The remaining transformer lost its source when the C22J circuit tripped open, the C22J was reclosed 3 minutes later. No cause for the 230kV trip was found. | 0.05 |
| Crawford TS | 09-May-19 | Crawford TS lost power when the J3E and J4E circuits tripped out of service due to structure fire at Gordie Howe Bridge construction site. All load transferred off Crawford TS. | 0.98 |

b) Total durations are listed in the chart above.

c) Hydro One and ENWIN discuss every station outage event and come up with an action plan if needed and ENWIN is kept aware of the remedial action.

## 2 - OEB Staff - 61

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 291-2

Preamble:

EnWin Utilities provides Table 148 for historical and prospective general plant expenditures:

**Table 148 Historical and Prospective General Plant Expenditures**

| General Plant | |
|---|---|
| 2009 | $8,066,576 |
| 2010 | $9,453,392 |
| 2011 | $3,724,687 |
| 2012 | $2,660,388 |
| 2013 | $4,679,933 |
| 2014 | $4,885,125 |
| 2015 | $3,498,840 |
| 2016 | $2,253,412 |
| 2017 | $2,057,547 |
| Last 5 Year Average: $3,474,971 | |

| Year | IT | Site | Vehicles | Fleet/Weld | Tools | Total |
|---|---|---|---|---|---|---|
| 2018 | $1,733,000 | $354,000 | $833,547 | 87500 | $90,000 | $3,098,047 |
| 2019 | $2,005,400 | $2,592,330 | $2,652,178 | $70,500 | $187,000 | $7,507,408 |
| 2020 | $1,719,000 | $1,521,000 | $1,604,576 | $74,500 | $102,000 | $5,021,076 |
| 2021 | $2,288,000 | $507,000 | $1,303,000 | $75,000 | $111,000 | $4,284,000 |
| 2022 | $1,863,000 | $500,000 | $1,309,000 | $75,000 | $111,000 | $3,858,000 |
| 2023 | $1,828,000 | $501,000 | $1,660,000 | $75,000 | $111,000 | $4,175,000 |
| 2024 | $2,013,000 | $496,000 | $1,530,000 | $75,000 | $101,000 | $4,215,000 |
| Average | | $4,594,076 | | | | |
| Avg. Exc. '19 & '20: | $3,926,009 | | | | | |

Question:

a) What is driving the doubling of the tools budget in 2019?

b) What is driving the 20% step change between the 2018 tools budget ($90,000) and the 2021 to 2023 forecasts ($111,000 for each year)?

c) Is the step increase in Vehicles spending from 2018 to 2019 entirely attributable to the recent change from leasing to purchasing vehicles? If not, please provide any other drivers of the change.

d) The $75,000 Fleet/Weld flat value shown in years 2021 to 2024 implies that this is a placeholder. What is the target of the proposed spending and how was the cost estimated?

Response:

a) ENWIN's budget for capital tools includes tools for Operations, Engineering and the Meter Shop. For 2019, the Meter Shop budgeted an additional $33,000 for a Poly Circuit Analyser and an additional $50,750 for MIST meter antennae to retrofit our installed base due to technical problems with the initially installed products in 2018. These additional items resulted in the increased budget for capital tools for 2019. Since the Poly Circuit Analyzer was purchased at the end of 2018, approximately $25,000 will be required to replace a failed Ratiometer in 2019.

b) The 20% increase in capital tooling from the 2018 Forecast to the 2021 to 2023 forecasts is attributed to Hydro Operations ($11K), Engineering ($5K) and Meter Shop ($5K). The actual capital tooling spend in 2018 was $132K. The Hydro Operations capital tooling amount is split between 3 areas: Overhead, Underground and Station Maintenance. Equipment such as Chainsaws, Truck Grounds, Voltage Testers, and Safety Equipment frequently require replacement. SAM Equipment usually lasts much longer but when equipment replacements are required, they can be high dollar value items. Therefore, ENWIN tries to budget for these replacements on an annual basis.

c) Yes. On November 14, 2018, ENWIN's Board of Directors approved management's recommendation to purchase vehicles rather than lease vehicles and buyout all existing vehicle leases prior to the end of 2018. Prior to 2018, all vehicles were leased and, depending on their condition and usefulness, possibly purchased at the end of the lease for a minimal amount and administration charge. The main reasons for the increase in budgeted vehicle spend from 2018 to 2019 are:
   i. There are more vehicles requiring replacement in 2019 (ie. 15 in 2019 vs. 8 forecast in 2018).
   ii. In 2018 ENWIN's capital forecast for vehicles only included 1 heavy duty truck, however in 2019, ENWIN has budgeted to take delivery of 3 heavy duty trucks.

   It should be noted that the actual capital spend on Hydro vehicles for 2018 was $3,013,464. This was significantly higher than budget due to the significant number of leases bought out prior to the end of 2018.

d) ENWIN's forecasted capital spend for Fleet/Weld capital equipment for 2021 to 2024 is based on the budget for 2020 and prior year's historical actuals. This is shown in the table below. This spend is volatile and varies depending on equipment breakdowns and replacements required.

Capital Budget-Fleet/Weld
2021-2024

| Description | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Fleet Services** | **55,500** | **55,500** | **55,500** | **55,500** | **55,500** |
| Automotive Scan Tool Program Upgrade | 9,500 | 9,500 | 9,500 | 9,500 | 9,500 |
| Vehicle RF data systems and Replacement Radios | 10,000 | 10,000 | 10,000 | 10,000 | 10,000 |
| Shop Impac Wrenches, Torque wrenches, specialty tools etc. | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 |
| Shop equipment | 30,000 | 30,000 | 30,000 | 30,000 | 30,000 |
| **Weld Shop** | **19,000** | **19,000** | **19,000** | **19,000** | **19,000** |
| Weld shop tools over $2000 | 17,000 | 17,000 | 17,000 | 17,000 | 17,000 |
| Welding equipment | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 |
| **Total Capital Spend** | 74,500 | 74,500 | 74,500 | 74,500 | 74,500 |

## 2 - OEB Staff - 62

Reference:

Exhibit 2: Rate Base, Attachment 2A, Page 310

Exhibit 2: Rate Base, Attachment 2A, Page 213

Preamble:

EnWin Utilities provides Table 148 for historical and prospective general plant expenditures:

EnWin Utilities states the following:

ENWIN has developed a capital investment plan and detailed descriptions of the material plans for the Test Year are presented in Appendix F – Material Investment Summaries. In addition to this, ENWIN has assessed those plans through its PROSORT project prioritization tool that was described in section 5.4.1 (b). The PROSORT tool determines a relative

Change in Risk Benefit Factor (“CRBF”) which is the cost of the project divided by the change in risk benefit. PROSORT ranks project lowest to highest cost for a change in risks and benefits. Thus, by ranking projects, the projects that provide the least cost per unit change in risks and benefits are ranked highest as they provide the best value proposition for Customers.

At the Exhibit 2: Rate Base, Attachment 2A, Page 213 of 317, EnWin Utilities stated the following:

**Table 74 Risk Matrix for Project Prioritization**

| | Factor | Values | Categories | 1 Insignificant | 2 Minor | 3 Moderate | 4 Major | 5 Catastrophic |
|---|---|---|---|---|---|---|---|---|
| Consequence | 0.3 | Safety | Life/Health | Injuries not requiring medical attention | Minor injuries/First Aid | Serious Injury/Medical Aid/Hospitalization | Life Threatening Injury/Multiple serious injuries | Death/Multiple life threatening injuries |
| | | | Property Damage | Minor loss to utility property, <$5k | Loss to Customer/Utility property/claims for damages, $1k - $10k | Damage to buildings/vehicles requiring major repairs, $10k - $100k | Serious damage to buildings/vehicles - non-repairable, $100k - $1 million | Damage to multiple properties, >$1 million |
| | 0.25 | Financial | Customer Costs | Minor inconvenience, no claims | <$1,000 | $1k - $100k | $100k - $1 million | >$1 million |
| | | | Utility Costs | Minor inconvenience | <$1,000 | $1k - $100k | $100k - $1 million | >$1 million |
| | | | Fines/Penalties | Inquiries from Regulators | Audits from Regulators | Order for change from Regulators | Fines >$50k, $1k/day | Fines >$100k, $1k/day |
| | | | Legal/Insurance | No implications | Claims for Damages, settled by Insurance | Lawsuits likely to be settled, <$100k | Lawsuits likely to be defended in court, <$1 million | Lawsuits >$1 million, Insurance claim in excess of deductible |
| | 0.25 | Reliability | Customer Disruption | <10 Customers affected, Customers out <1hr | <500 Customers affected, majority of affected customers out <1 hour, SED | 1 feeder out, Majority of affected customers out 1-8 hours, MED | >1 feeder out, Majority of affected customers out 8-24 hours, MED | Station out for >8 hours, Majority of affected customers out >1 day, MED |
| | 0.2 | Sustainability | Environmental Damage | Minor clean-up required | MOE Notification required, clean-up required | Major cleanup required, cleanup last 1 day - 1 week | Major cleanup required, barricading/area restrictions, | Irreparable harm to environment, large fines, charges |
| | | | Non-Compliance | Reported to Regulators | Inquiries from Regulators | Audits from Regulators | Sanctions from Regulators | Threat or Loss of Distribution License, Severe Penalties Imposed |
| | | | Reputational Damage | Brief social media comments | Adverse reports on local papers, media | Adverse regional media reporting, loss of faith in ability to operate, loss of jobs | Adverse provincial media reporting, loss of senior staff jobs | Adverse provincial media reporting, sale of company |
| Likelihood | 1 | Expected to occur in the next 5 years | Almost Certain | 9 | 25 | 68 | 184 | 500 |
| | 2 | Will probably occur in the next 5 years | Likely | 7 | 19 | 51 | 139 | 379 |
| | 3 | Might occur in the next 5 years | Possible | 5 | 13 | 34 | 93 | 253 |
| | 4 | Doubtful to occur in the next 5 years | Unlikely | 2 | 6 | 17 | 46 | 126 |
| | 5 | May occur but only in exceptional circumstances | Rare | 1 | 3 | 7 | 19 | 51 |

Question:

a) How does EnWin Utilities ensure that projects prioritized using a "low cost per unit change in risks" metric excludes projects that start in an acceptable risk category (i.e. green and potentially yellow), and therefore do not need to be executed?

b) How does EnWin Utilities ensure that projects prioritized using a "low cost per unit change in risks" metric instead select lower total cost projects that would change risk from an unacceptable risk category (i.e. red or orange) to an acceptable risk category (i.e. green and possibly yellow), even though those projects have a higher "cost per unit change in risk" metric?

Response:

a) Before a project is subjected to the PROSORT prioritization tool, that project needs to be conceived to address a perceived risk. If a potential project is already in an "acceptable risk" category, it is unlikely to be conceived and offered as a project for consideration. As well, the fact that the project risk rankings are subject to a panel review means that it is even less likely that a project in the acceptable risk category would be considered. Finally, the scales on the risk matrix that is provided by Kinectrics are not linear but are somewhat exponential. This means that projects that have higher risk will have exponentially higher risk scores and that should assist in ensuring that they have a better chance of rising higher on the project priority list.

b) ENWIN subscribes to the philosophy that it is most often in the customer's best interest to pursue projects first with the lowest cost per unit of risk reduction. However, as the question implies, there may be situations where experience and judgment would suggest that a project with a higher per cost per unit of risk reduction would provide better value for the customer. As noted in (a) above, the scaling on the risk matrix should reduce the incidents where this situation could occur. Finally, however, the PROSORT tool is simply a tool to prioritize projects and the final decision on what projects are budgeted and executed lies with management. Management has the prerogative to use its judgment and go forward with a project that may have a higher cost per unit of risk reduction over a project with a lower cost per unit of risk reduction.

## 2 - OEB Staff - 63

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 1 (PDF Page 825)

Preamble:

EnWin Utilities provides the explanation for one of the material investments planned in 2020 test year as below:

Project Name/Description: Walker Road – Foster to Airport Road – Feeder Connection

...

While ENWIN has a proposal to proceed there is risk that the City, upon re-engaging their plans, may change their plans and put ENWIN's running line in the way of new construction. There are no contributions to the transmitter for completion of this section of line.

Question:

a) Why did the City lose interest in completing the remaining section of the Walker Road rebuild?

b) Please explain whether or how EnWin Utilities plans to address the risk that the City may change their plans and put EnWin Utilities' running line in the way of new construction.

c) Could this project be deferred until the City has made a final decision about the road rebuild?

---

Response:

a) ENWIN was advised that due to the planned construction of a new hospital along Highway 42, the City had to reprioritize their projects and delay the road widening of this section of Walker Rd.

b) ENWIN is coordinating the design with the City and using the preliminary plans developed for the road widening to minimize the chances of conflicts between the new running line and future City plans.

c) This project has been deferred for a few years but the load of South Windsor has grown to the point where now the existing feeder is not able to support cold load pickup when there is a momentary outage during peak load times. The consequence of this is that staff has to be dispatched to open switches on sections of the system supplied from the feeder and then close them one-by-one so that the load can be picked up. This means that the outage time for customers in South Windsor is extended longer than it should be. As well, to comply with ENWIN's design criteria, the load in South Windsor should be fed by two feeders for inter-feeder support. In order to accomplish this, an available feeder position was taken in Hydro One's Essex TS to supply the new feeder. This makes fuller use of the available capacity to ENWIN to serve its distribution system.

Additionally, ENWIN has made an investment to build this line, albeit with some level of subsidization due to the widening of other sections of the road, and without this section, there remains a gap in the line which prevents ENWIN's customers from realizing value for the investment already made.

## 2 - OEB Staff - 64

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 2 (PDF Page 826)

Preamble:

EnWin Utilities states the following:

Project Name/Description: Walker Road – Foster to Airport Road – Feeder Connection

...

As South Windsor has grown, that feeder's load has grown to the point where now the feeder is not able to support cold load pickup when there is a momentary outage during peak load times. The consequence of this is that staff have to be dispatched to open switches on sections of the system supplied from the 55M25 feeder and then close them one-by-one so that the load can be picked up.

Question:

a) Please quantify the average number of hours each year when the described cold load pickup peak constraint condition exists.

b) What is the probability that an outage requiring cold load pickup will occur during the at-risk hours?

Response:

a) ENWIN has not completed a specific study to find the exact load levels which create cold load pickup problems in 55M25 feeder sections. This issue is critical during the summer peak load time when the feeder is fully loaded. Evidence shows that when the total feeder load is 16MW or above, the likelihood of an incident is high. Based on 16MW loading levels, operations face approximately 270 hours of operation per year with the possibility of a cold load pick up issue.

b) Cold load pick up issues are experienced mostly during the summer due to additional loads, such as pool pumps and air-conditioning. Data collected from ENWIN's outage records for the 55M25 feeder for the last five years is shown in the table below. According to the data, 1.9 outages/month are expected while cold load pickup issues are at an increased risk.

| Year | Total number of Outages (May-Oct) Excluding planned outages |
|---|---|
| 2015 | 4 |
| 2016 | 8 |
| 2017 | 6 |
| 2018 | 24 |
| 2019 | 14 |
| | 56 |

## 2 - OEB Staff - 65

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 16-17 (PDF Page 840-841)

Preamble:

EnWin Utilities explains the main driver for the material investment of underground padmount transformer sustainment program of $255k budgeted in 2020 as below:

Replacing three-phase padmount transformers which are at end of life is fundamental to being able to maintain service to customers. As noted in the description of ENWIN's Asset Management System in section 5.3.1, inspections are performed as part of the 3-year OEB inspection cycle and the transformers with the lowest, worst, health index are replaced first.

EnWin Utilities further states regarding the timing of the expenditures that:

ENWIN has budgeted $255,000 for 6 padmount transformer replacements in 2020. An example project for 2020 is the replacement of the 300KVA padmount transformer TP0433 – servicing a high rise residential building in Windsor. Average replacement cost is $42,500 per unit. Expenditures will be $42.5k at end of Q1, $85k at end of Q2, $85k at end of Q3 and $42.5k at end of Q4.

Question:

a) Are all commercial padmount transformer replacements driven by an asset specific condition assessment?

b) Are any replacements driven by asset age only?

c) Please provide the actual expenditures up to date for the transformers and compare to the budgeted expenditures as at end of Q1 and Q2.

---

Response:

a) This program addresses the aging padmount transformer infrastructure that was identified in the Kinectrics Asset Condition Study as requiring sustaining investment. Inspections are performed on the assets and the units with the lowest, worst, health index are replaced first. Projects that are identified are prioritized based on a point system. System Planning uses asset information (age, condition, failure history, customer density and sensitivity) to establish a data driven forced ranking of padmount transformers at risk. These are supplemented by inspection data and a list of projects is created for implementation over a 5 year planning horizon. System Planning continually assesses the health demographic of the padmount transformer assets in the system to determine the investment velocity required to sustain this asset class over a long term planning horizon (20+ years). Year over year as more or less assets approach end of life within the planning horizon then the average annual sustaining investment must move to match in order to avoid a significant imbalance in investment over time. Results of this assessment are submitted into the budgeting process to earmark minimum and optimum levels of investment in this asset class.

b) No. Age is a factor that is considered in the replacement if health index data is not available but a field inspection is performed to confirm the condition of the transformer and that the asset should be replaced.

c) ENWIN's budgeted expenditures for the Underground Padmount Sustaining Program for 2019 are $280K for the full year. During Q1, ENWIN had spent $48K. During Q2, ENWIN spent an additional $124K for a total of $172K as of June 30, 2019. This includes the cost of material (transformer, cable, poles etc.) as well as services, labour and trucking, as applicable.

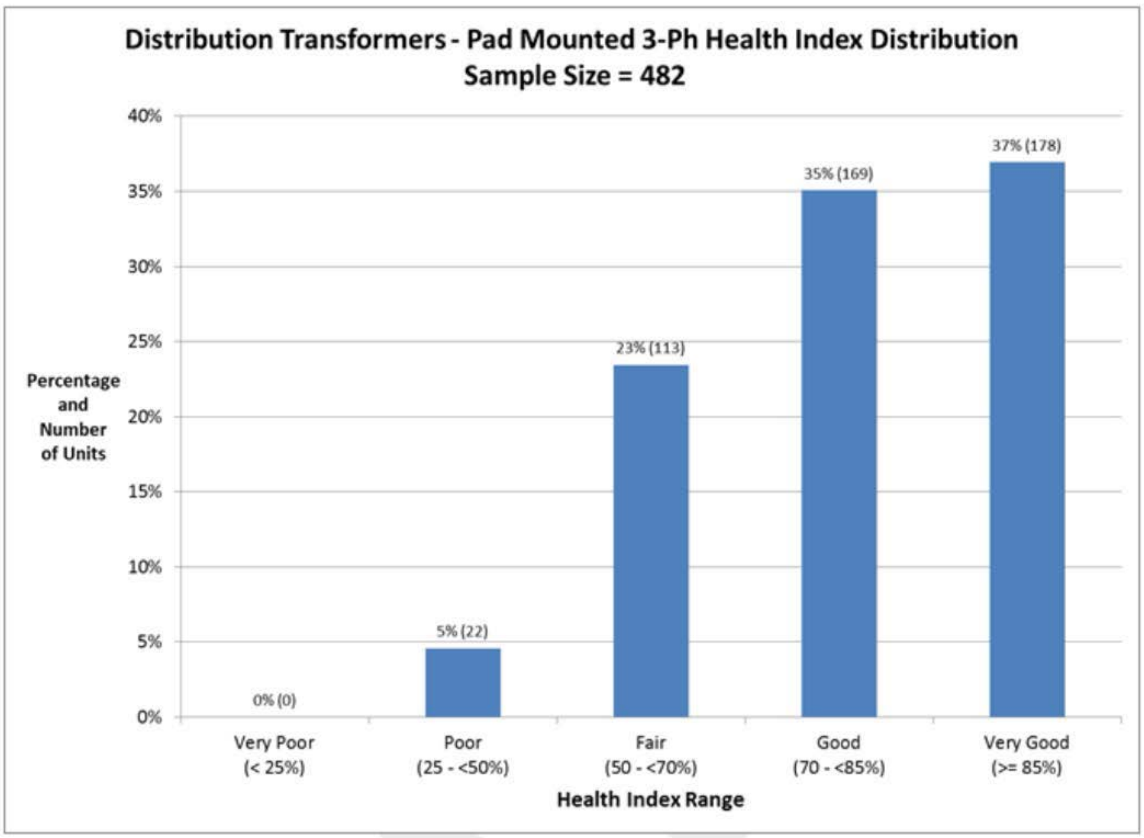
## 2 - OEB Staff - 66

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 20 (PDF Page 844)

Preamble:

EnWin Utilities provides the following graph regarding its padmount transformer health index distribution:




OEB staff notes from the bar chart above that 22 pad mounted transformers are in poor health condition. EnWin Utilities also provided the table below to compare the Kinectrics and EnWin Utilities' plan:

| Kinectrics and ENWIN Plan Comparison (# of Units) | | |
|---|---|---|
| Year | Kinectrics | ENWIN |
| 2019 | 4 | 7 |
| 2020 | 4 | 6 |
| 2021 | 6 | 7 |
| 2022 | 6 | 7 |
| 2023 | 7 | 6 |
| **5-Year Total** | **27** | **33** |
| **5-Year Average** | **5.4** | **6.6** |
| 2024 | 7 | 6 |
| 2025 | 7 | 6 |
| 2026 | 9 | 6 |
| 2027 | 9 | 6 |
| 2028 | 10 | 7 |
| **10 Year Total** | **69** | **64** |
| **10 Year Average** | **6.9** | **6.4** |

OEB staff notes that EnWin Utilities' planned units in 5 years of 33, which is 6 units greater than the Kinectrics' plan and EnWin Utilities' planned units in 10 years of 64, which is 5 units less than the Kinectrics' plan.

Question:

a) Assuming that all 22 of the "Poor" condition padmount transformers are scheduled for replacement, how did EnWin Utilities select the remaining 42 units planned for replacement over the next 10 years?

b) Please explain why EnWin Utilities plans to replace 6 more units as compared to the Kinectrics' plan in 5 years, while EnWin Utilities plans to replace 5 fewer units as compared to the Kinectrics' plan in 10 years.

c) How is the replacement program prioritized to ensure that all units presently assessed as being in poor condition are replaced first?

Response:

a) The remaining 42 units planned for replacement over the next 10 years will be selected based on their health index in conjunction with other factors such as age, oil leaks and so on. At least once per year both the overall program and the specific inspection methodology are reviewed by System Planning for effectiveness and to ensure that system reliability is maintained. This also includes a review of failed units in service to determine if the program adequately ensures that assets are replaced before failure. Updates to the tools and data gathering methods are implemented to reflect approved changes to the program. Changes can be introduced as a result of a number of factors including but not limited to: changes in regulatory requirements, results of field investigations of failed assets, industry best practice benchmarks, shifts in management direction, alignment to available resources, etc.

b) ENWIN plans to maintain a sustaining investment in the padmount transformer asset group at approximately $270k annually to ensure a reliable system performance and avoid a significant investment ramp as infrastructure begins to fail at end of life. This level of investment represents the replacement of approximately 7 units per year. This is very closely aligned to the flagged for action plan recommended in Kinectrics' Asset Condition Study. The planned spend matches the action plan recommended by Kinectrics over the next 5 to 10 years. Slight variations can be attributed to the additional health index information collected in the last 2 years. ENWIN's investment plan provides for a more consistent level of investment than the Kinectrics plan, which is part of ENWIN's goal to minimize the need to change rates (up or down) for customers.

c) The transformers with the lowest health index are replaced first. The age of the transformers is also considered when replacing transformers. The health index is calculated based on a weighted average of various factors. Currently, the categories are: Physical Condition, Connections & Insulation and Reliability.

## 2 - OEB Staff - 67

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 30 (PDF Page 854)

Preamble:

Regarding its Submersible Transformer Sustainment Program, EnWin Utilities states:

ENWIN's experience with its submersible transformer fleet is that the units commonly fail in service prior to their expected useful life. In 2015 – 2017 there were 9, 7 and 7 in-service failures respectively of submersible transformers. This information as well as the condition inspections performed every 3 years inform the asset management process and the determination of which transformers are at end of life.

Question:

a) Are all Submersible Transformer replacements driven by an asset specific condition assessment?

b) Are any replacements driven by asset age only?

c) Has EnWin Utilities revised the useful life for the submersible transformer fleet after 2015 given "ENWIN's experience with its submersible transformer fleet is that the units commonly fail in service prior to their expected useful life"? If not, why not.

---

Response:

a) Submersible Transformer replacements are prioritized based on a point system. Asset Management uses asset information (age, condition, failure history, customer density and sensitivity) to establish a data driven forced ranking of submersible transformers at risk. Submersible units in the same geographical area are sometimes prioritized so that replacements are completed at the same time in localized neighbourhoods. This is because the cable feeding the transformers is usually the same vintage as the transformers being replaced and in many cases is also at end of life. These are supplemented by inspection data and a list of projects is created for implementation over a 5 year planning horizon. Year over year requirements would be driven by asset health information derived from inspections as well as moderated to manage labour and capital profiles.

Additionally, ENWIN's desire is to replace submersible transformers with on-ground mini-pad transformers, where adverse customer reaction is able to be managed. When replacing submersible transformers with on-ground transformers it is most cost effective to address the submersible transformers as a "project" in a neighbourhood. Consequently, the average age and condition of a group of submersible transformers is considered and prioritized as a project in order to achieve the most cost effective outcome for customers and to minimize the civil works disruption in a neighbourhood to a single occasion.

b) No. Age is one of the factors used in the point system to establish a data driven forced ranking of submersible transformers.

c) Assets in this family have an industry life expectancy of approximately 35 years that may be extended based on optimal operating conditions. ENWIN's experience with submersible transformers is that they on average fail at approximately 32 years in service.

## 2 - OEB Staff - 68

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 46 (PDF Page 870)

Preamble:

EnWin Utilities provides the following table:

Project Name/Description: Conductor Upgrade Project – 23M2 LTP1

| Assessment of Impact of Investment to Business Values | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Business Values | | Before | | | | After | | | | |
| | | Consequence | Likelihood | Score | TRS | Consequence | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | | | | | | | | | NO SAFETY ISSUES |
| 0.25 | Reliability | Catastrophic | Rare | 51 | 12.75 | Insignificant | Rare | 1 | 0.25 | REDUCES RISK OF INABILITY TO SERVE UPON STN LOSS |
| 0.25 | Financial | Major | Rare | 19 | 4.75 | Insignificant | Rare | 1 | 0.25 | REDUCES RISK OF CUSTOMER LOSSES/COSTS UPON STN LOSS |
| 0.2 | Sustainability | Moderate | Rare | 7 | 1.4 | Insignificant | Rare | 1 | 0.2 | REDUCES RISK TO REPUTATION |

Question:

a) Please quantify how the Catastrophic consequence rating was determined for Reliability, and provide the assumptions used in making that assessment.

Response:

a) The Catastrophic consequence rating was determined based on the criteria established by ENWIN's risk matrix for project prioritization, which considers as Catastrophic an event of a station out for more than 8 hours, with the majority of affected customers out for more than 1 day and what would consequently be considered a MED (Major Event Day).

Currently, ENWIN is unable to sustain the complete distribution system at peak times if there is a loss of one complete station. In reliability terms, this situation is often referred to as a "loss of critical unit" contingency. For that contingency, at peak times, ENWIN would be forced to institute a rolling blackout of certain sections of the distribution system. If the station is completely destroyed it may take months to rebuild it. It is judged that ENWIN's customers would suffer extreme consequences such as loss of production at commercial accounts, basement flooding due to loss of sump pumps, extreme heat due to lack of air conditioning, etc. This situation is judged to be not tolerable and is a contingency for which a remediation plan should be available.

## 2 - OEB Staff - 69

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 47 (PDF Page 871)

Preamble:

In reference to planning of its project "Conductor Upgrade Project – 23M2 LTP1", EnWin Utilities stated:

The entire ENWIN distribution system is fed by eight transformer stations spread around the City. Given the number of stations, there is a reasonable probability of a given station being unavailable from time to time. Currently, ENWIN is unable to sustain the complete distribution system at peak times if there is a loss of one complete station. In reliability terms, this situation is often referred to as a "loss of critical unit" contingency. For that contingency, at peak times, ENWIN would be forced to institute a rolling blackout of certain sections of the distribution system.

Question:

a) How many hours in an average year are loads high enough to create the described risk exposure?

Response:

a) In considering the loss of one critical supply (i.e. a distribution system supply station), ENWIN has determined that it is unable to replace the supply to all station feeders during peak times. ENWIN has determined that while the remaining supply stations are able to supply enough power when there is a loss of a critical station, there is not enough feeder capacity to move that power to the feeders that have lost their supply. This will result in undersupply to one or more of the feeders affected by the loss of the station. If the loss of the station is a long-term loss and station restoration likely to take weeks or months then there is a likelihood that the affected feeders will be short supplied on the peak day and near-peak days. ENWIN has reviewed the loading of its most critical station and established that it would be difficult to replace full loading when station loading was 80 MW or more. In 2018 (considered typical) the station loading during the months of July and August ranged from 80 to 112 MW on 19 days. The duration of that loading ranged from 1 hour to 24 hours, depending on the day.

In this scenario, ENWIN would mitigate the inability to supply all the feeders from the affected station by imposing a rolling blackout for an hour whereby one of the feeders may be out of supply and thereafter power would be restored and removed from another feeder.

It is ENWIN's judgment that its customers would not find rolling blackouts to be a reasonable solution to the undersupply situation and would have expected ENWIN to have anticipated the contingency and provided a mitigation that would preclude the loss of power on a repeated basis for an on-going period.

## 2 - OEB Staff - 70

Reference:

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 51 of 94 (PDF Page 875)

Exhibit 2: Rate Base, Attachment 2A, Appendix F, Page 62 of 94 (PDF Page 886)

Preamble:

EnWin Utilities provides the assessment of impact for the following project:

Project Name/Description: Feeder Reliability Improvement Project – 25M7 Feeder Ring Pilot Project

| Assessment of Impact of Investment to Business Values | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Business Values | | Before | | | | After | | | | |
| | | Consequence | Likelihood | Score | TRS | Consequence | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | | | | | | | | | NO SAFETY ISSUES |
| 0.25 | Reliability | Minor | Possible | 13 | 3.25 | Insignificant | Possible | 5 | 1.25 | IMPROVE RESTORATION TIME FROM MINUTES TO SECONDS |
| 0.25 | Financial | Minor | Possible | 13 | 3.25 | Insignificant | Possible | 5 | 1.25 | MINOR INTERRUPTIONS ELIMINATED |
| 0.2 | Sustainability | Insignificant | Unlikely | 2 | 0.4 | Insignificant | Rare | 1 | 0.2 | UNLIKELY TO HAVE REPUTATIONAL RISK |

ENWIN provides the assessment of impact for the following project:

Project Name/Description: Feeder Reliability Improvement Project – Prince to Brock

| Assessment of Impact of Investment to Business Values | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Business Values | | Before | | | | After | | | | |
| | | Consequence | Likelihood | Score | TRS | Consequence | Likelihood | Score | TRS | Comment |
| 0.3 | Safety | | | | | | | | | NO SAFETY RISK MITIGATED |
| 0.25 | Reliability | Catastrophic | Unlikely | 126 | 31.5 | Minor | Rare | 1 | 0.75 | MAINTAIN SUPPLY IN LOSS OF STATION CONTINGENCY |
| 0.25 | Financial | Major | Unlikely | 46 | 11.5 | Minor | Rare | 1 | 0.75 | CUSTOMER COSTS >100k |
| 0.2 | Sustainability | Moderate | Unlikely | 17 | 3.4 | Insignificant | Rare | 1 | 0.2 | LOCAL MEDIA REPORTING – LOSS OF REPUTATION |

Question:

a) Please confirm that the Consequence outcomes and likelihoods in the referenced tables do not appear to support rating these projects as high priority. Please discuss.

b) Please provide the quantitative thresholds for Consequence & Likelihood scores for a project to be assigned as high priority.

Response:

a) ENWIN agrees that these two projects are not ranked at the top of the prioritized list. However they will benefit ENWIN's customers and improve the reliability of the system. These projects are system enhancements that customers would find valuable.

b) There are no quantitative thresholds for Consequence & Likelihood scores for projects to be assigned as high priority; the PROSORT tool establishes only relative priorities.

## 3 - OEB Staff - 71

Reference:

Exhibit 3, Page 3

Preamble:

EnWin Utilities states:

According to the most recently published Filing Requirements for Electricity Distribution Rate Applications, dated July 12, 2018, multivariate regression is an approved modelling approach for forecasting load. **Traditionally, kWh and kW data is collected by month for 10 historic years for use in the regression analysis**. Accordingly, ENWIN has utilized kWh and kW data, by month, for its entire service territory from January 2008 to December 2017 in order to ensure that all billed consumption and demand is collected and applied to its appropriate consumed month. [Emphasis added by staff]

Question:

a) Please confirm that the Filing Requirements do not specify a minimum or maximum length of time or number of data points for a load forecast model based on a multivariate regression modelling approach?

b) What is the basis for EnWin Utilities' statement that: "[t]raditionally, kWh and kW data is collected by month for 10 historic years for use in the regression analysis"?

c) Why did EnWin Utilities or its consultant, Elenchus, limit the historical data range to the 10-year period from January 2008 to December 2017?

---

Response:

a) Confirmed.

b) This statement is based on the typical data range used by Elenchus in its load forecasts.

c) The relationship between consumption and the factors that impact consumption change over time as technology evolves and government regulations change. The data is limited to a 10-year period to limit the degree to which data that does not reflect current relationships between consumption and variables influences the results of the forecast.

At least 10 years of data is used to maintain a sufficient dataset for robust regressions.

## 3 - OEB Staff - 72

Reference:

Exhibit 3, Pages 7-18

Preamble:

EnWin Utilities provides its analysis of the year-over-year variances in revenues, customers, kWh and kW by customer class. Historical data up to 2017 are shown as actuals.

Question:

a) Are these actuals weather-normalized or not?

b) In the reasons or drivers for variances in revenues, customers and electricity consumption and demand, EnWin Utilities does not identify weather or CDM as factors. Please explain why these are not factors explaining variances in revenues and demand and consumption.

c) Please update Table 3-17 and the associated analysis to include an additional column for 2018 actuals.

---

Response:

a) The actuals are not weather-normalized (i.e. they reflect actual weather conditions in the year).

b) ENWIN identified high-level drivers for the year-over-year distribution revenue variances in this section, focused on whether the variance was related to price or volume. For distribution revenue variances that were related to volume (as opposed to other identifiable factors, such as rate changes), ENWIN generally did not endeavor to further explain the driver of the volume variance for the purposes of this analysis.

c) Please see the updated Table 3-17 below.

| Rate Class | Customers/Connections | | | | | | Billing Determinants | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 Actual | 2018 Forecast | 2018 Actual | 2019 Forecast | 2020 Forecast | | 2017 Actual | 2018 Forecast | 2018 Actual | 2019 Forecast | 2020 Forecast |
| Residential^ | 79,325 | 79,646 | 79,466 | 79,969 | 80,293 | kWh | 583,858,255 | 570,743,706 | 636,798,571 | 562,297,710 | 555,916,913 |
| General Service<50 kW | 7,109 | 7,116 | 7,104 | 7,124 | 7,131 | kWh | 199,190,043 | 201,833,099 | 203,075,206 | 198,127,913 | 195,457,487 |
| General Service>=50 kW | 1,251 | 1,258 | 1,254 | 1,264 | 1,271 | kW | 2,393,116 | 2,469,073 | 2,385,326 | 2,455,904 | 2,562,347 |
| Intermediate* | 3 | 3 | 3 | 3 | 3 | kW | 133,092 | 128,328 | 128,456 | 126,556 | 0 |
| Large User - Regular | 6 | 6 | 6 | 6 | 6 | kW | 548,064 | 571,904 | 568,093 | 561,013 | 542,339 |
| Large Use 3TS | 2 | 2 | 2 | 2 | 2 | kW | 495,653 | 487,469 | 494,553 | 475,523 | 528,993 |
| Large Use Ford Annex* | 1 | 1 | 1 | 1 | 1 | kW | 70,874 | 71,032 | 73,849 | 68,172 | 0 |
| Street Lighting Connections | 24,144 | 24,158 | 24,284 | 24,173 | 24,188 | Connections | 24,144 | 24,158 | 24,284 | 24,173 | 24,188 |
| Sentinel Lighting Connections | 554 | 540 | 533 | 526 | 512 | Connections | 554 | 540 | 533 | 526 | 512 |
| Unmetered Scattered Load | 769 | 727 | 727 | 724 | 721 | Connections | 769 | 727 | 727 | 724 | 721 |

| Rate Class | Customers/Connections | | | | | | Billing Determinants | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 Actual | 2018 Forecast | 2018 Actual | 2019 Forecast | 2020 Forecast | | 2017 Actual | 2018 Forecast | 2018 Actual | 2019 Forecast | 2020 Forecast |
| Residential | | 322 | -180 | 323 | 324 | kWh | | -13,114,549 | 66,054,865 | -8,445,996 | -6,380,796 |
| General Service<50 kW | | 7 | -12 | 7 | 7 | kWh | | 2,643,057 | 1,242,107 | -3,705,186 | -2,670,426 |
| General Service>=50 kW | | 6 | -4 | 6 | 7 | kW | | 75,957 | -83,747 | -13,169 | 106,443 |
| Intermediate* | | 0 | 0 | 0 | 0 | kW | | -4,764 | 128 | -1,772 | -126,556 |
| Large User - Regular | | 0 | 0 | 0 | 0 | kW | | 23,840 | -3,811 | -10,891 | -18,674 |
| Large Use 3TS | | 0 | 0 | 0 | 0 | kW | | -8,184 | 7,084 | -11,946 | 53,470 |
| Large Use Ford Annex* | | 0 | 0 | 0 | 0 | kW | | 159 | 2,817 | -2,860 | -68,172 |
| Street Lighting Connections | | 15 | 126 | 15 | 15 | Connections | | 15 | 126 | 15 | 15 |
| Sentinel Lighting Connections | | -14 | -7 | -14 | -14 | Connections | | -14 | -7 | -14 | -14 |
| Unmetered Scattered Load | | -42 | 0 | -3 | -3 | Connections | | -42 | 0 | -3 | -3 |

## 3 - OEB Staff - 73

Reference:

Exhibit 3, Pages 5

Preamble:

EnWin Utilities states that it has made a specific adjustment to the 3TS class due to the loss of a customer:

**Large Use – 3TS Customer Class**

Prior to any modeling, ENWIN identified that a significant facility closure had occurred within its service territory and notified Elenchus to ensure that historic load for this customer would be factored out of the analysis.

Due to the loss of this Large Use – 3TS (automotive sector) customer, usage prior to 2012 has been adjusted to exclude the lost customer. Excluding that customer, and after adding back persisting CDM, the Large Use 3TS energy consumption has varied in a range of 254GWh - 287GWh from 2008-2017 with no clear trend. The forecast was calculated as an average of the 2008-2017 consumption, having adjusted for CDM.

It is not clear what was done in terms of both removing the specific customer's historical load and adjusting for CDM for the class.

For large customers, CDM programs may be specifically tailored to each customer.

Question:

a) Was the CDM for the class also adjusted historically to remove the CDM attributable to that particular customer's historical load? If not, please explain why not.

---

Response:

a) There were no CDM activities related to this customer, or any CDM activities related to any customer in the Large Use – 3TS class until 2012, so no adjustment is necessary.

## 3 - OEB Staff - 74

Reference:

Chapter 2 Filing Requirements, Section 2.3.1.1 Exhibit 3, Attachment 3-A, Page 1

Preamble:

On page 23 of Chapter 2 of the Filing Requirements for electricity distributors, the minimal documentation necessary to support a multivariate regression analysis is listed. This includes the following:

• Explanation of the weather-normalization methodology proposed including:

  o If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, the monthly HDD and CDD based on: a) 10-year average and b) a trend based on 20-years. If the applicant proposes an alternative approach, it must be supported.

  o Definitions of HDD and CDD, including:

    - Climatological measurement point(s) (i.e. identification of Environment Canada weather station(s)) and why these are appropriate for the distributor's service territory

    - Identification of base degrees from which HDDs and CDDs are measured (e.g. 18° C or other)

  o In addition to the proposed test year load forecast, the load forecasts based on 10-year average and 20-year trends in HDD and CDD

  o Rationale to support the weather-normalization methodology chosen

On page 1 of its report, EnWin Utilities' consultant, Elenchus, stated that 18°C was used as the threshold for both Heating Degree Days (HDD) and Cooling Degree Days (CDD).

Question:

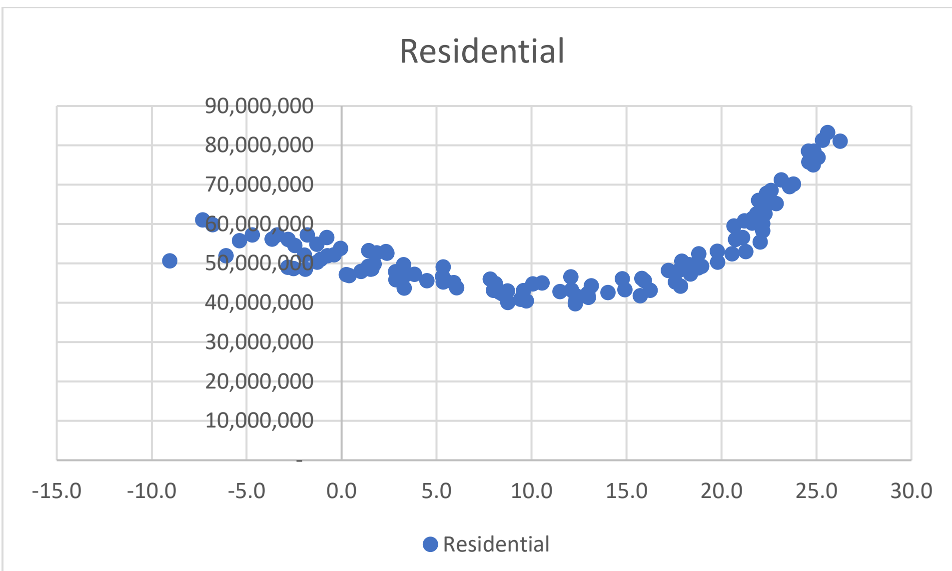
a) What is the basis for choosing the 18°C threshold for both HDD and CDD?

b) What analysis did EnWin Utilities or Elenchus conduct to assess alternative HDD and CDD thresholds?

Response:

a) At the time this forecast was originally produced Elenchus collected only HDD and CDD data from Environment and Climate Change Canada's historic climate database and used the HDD and CDD data as defined for that database, which is 18°C. Elenchus did not consider alternate thresholds at that time but has since analyzed and used alternate thresholds.

b) As a starting point the average monthly consumption would have been mapped by average monthly temperature to observe at which temperatures consumption changes. Based on the chart below (based on actual EnWin and Windsor Riverside data), CDD thresholds of 18°C and 16°C would have been analyzed.



## 3 - OEB Staff - 75

Reference:

Exhibit 3, Attachment 3-A, Page 1; Load Forecast Excel Spreadsheet

Preamble:

Elenchus states the following in its report:

To isolate the impact of CDM, persisting CDM as measured by the IESO is added back to rate class consumption to simulate the rate class consumption had there been no CDM program delivery. This is labelled as “Actual No CDM” throughout the model. The effect is to remove the impact of CDM from any explanatory variables which may capture a trend, and focus on the external factors. A weather normalized forecast is produced first based on no CDM delivery, and then CDM savings of historic programs are subtracted off to reflect the actual normal forecast.

While statistical regression is appropriate for estimating a relationship between explanatory variables and energy use, in the case of CDM, an independent measurement is available providing a greater level of accuracy than could be obtained through regression.

Question:

a) Is the CDM adjustment added back to the historical actual data based on gross or net CDM as reported by the IESO, or its predecessor, the Ontario Power Authority (OPA)?

b) It appears from sheet “Monthly Data”, that the annual CDM results were converted to monthly adjustments simply by dividing by 12 (months).

> i. Please confirm this, and explain the reason for this CDM adjustment approach.
>
> ii. Please explain how this approach does not introduce measurement errors in the adjusted historical data due to the timing of when CDM programs may be actually implemented in a year, on the fact that OPA/IESO results are annualized (i.e., do not reflect actual first year impacts depending on when they actually occur), and on seasonal/monthly variability in the impacts of CDM programs on consumption and demand.

c) Why is this approach used instead of including a suitable CDM variable as an explanatory variable in the model?

Response:

a) The CDM adjustment is added back to the historical actual data based on net CDM as reported by the OPA/IESO.

b) i.) Confirmed. For clarity, annual CDM results in a given year are calculated as historic CDM savings persisting to that year plus half of first year incremental savings. Since the timing of CDM programs within a year is typically not known the CDM within the year must be distributed by some methodology.

An alternate methodology has been considered in which 1/12 of incremental CDM is added each month and 1/12 of lost persistence is removed. This method likely has a lower average difference between calculated CDM and actual CDM but also carries the potential for greater deviations in any given month. The method used in the forecast effectively uses the midpoint of the upper and lower bounds of CDM within the year in each month. The most actual CDM savings in any one month can deviate from the CDM value used in the forecast is half of incremental CDM savings. In the case that CDM activities occur predominantly at the start or end of the year, the deviations would be greater if CDM savings are introduced in steps throughout the year. Large deviations tend to have a disproportionately larger impact on OLS regressions than multiple smaller deviations. Additionally, increasing CDM in each month may be inappropriately reflected in a time trend variable or another variable correlated with time.

Though CDM savings figures are the same in each month of a year this implicitly reflects a small degree of increasing first year savings when the gradual loss of historic persistence is considered.

ii.) Because CDM in each month is not known, any method to distribute CDM will have some degree of measurement error. The method was selected to minimize large errors in any one month/season rather than average errors. Only half of first-year savings are included to account for annualized OPA/IESO results.

c) This approach forecasts electricity consumption in absence of CDM activities. The difference between this approach and an approach using a CDM variable is consideration of the relationship between the other variables and CDM. The relationship between consumption and CDD, for example, depends partially on CDM activities since certain CDM activities are designed to reduce cooling related consumption. The level of CDM activities has an impact on each other variable, therefore, a CDM variable would not be an independent variable and would be inappropriate to use in the OLS regressions.

## 3 - OEB Staff - 76

Reference:

Exhibit 3, Attachment 3-A, Pages 5-8 Residential Class Load Forecast Model

Preamble:

Elenchus documents the load forecast regression model for the Residential class on pages 5-8 of its report.

Question:

a) Elenchus notes that a linear trend variable is included, which begins with a value of 1 in January 2008 and increasing to 120 for December 2017. The estimated coefficient is negative and statistically significant. Since the historical consumption data are adjusted to add back CDM, as measured by the OPA/IESO, over the period, what, in the view of EnWin Utilities or Elenchus, is this trend variable actually measuring?

b) Elenchus states on p. 5 that: "[s]everal other variables were examined and found to not show a statistically significant relationship to energy usage. Those included economic indicators of full time employment and GDP, and a count of customer accounts." Was the linear time trend variable included or excluded from the models where economic measures such as employment and GDP were tested and found to be not statistically significant?

---

Response:

a) The time trend variable may be reflecting a number of potential consumption trends including: conservation activities outside of the CFF, improved building efficiency, and an increase in the proportion of customers living in apartments. The time trend reflects a gradual decline in consumption that is not explained by the other variables.

b) Elenchus analyzed economic variables both with and without the time trend variable. Real GDP and employment were generally increasing while residential consumption was decreasing, so there was a certain degree of correlation, but the correlation is counterintuitive and weaker than the simple time trend.

## 3 - OEB Staff - 77

Reference:

Exhibit 3, Attachment 3-A, Pages 8-11 GS < 50 kW Class Load Forecast Model

Preamble:

Elenchus documents the load forecast regression model for the GS < 50 kW class on pages 8-11 of its report.

Question:

a) Elenchus notes that a linear trend variable is included, which begins with a value of 1 in January 2008 and increasing to 120 for December 2017. The estimated coefficient is negative and statistically significant. Since the historical consumption data are adjusted to add back CDM, as measured by the OPA/IESO, over the period, what, in the view of EnWin Utilities or Elenchus, is this trend variable actually measuring?

b) For the GS < 50 kW model, Elenchus includes a binary variable for the "shoulder seasons of spring and fall, covering the months of March, April, May and September, October and November, as well as binary variables for the months of March and September. The "shoulder season" variable is statistically significant with a negative coefficient while each of the March and September variables are statistically significant with positive coefficients. The model also includes HDD and CDD days to proxy seasonal weather impacts, as well as Windsor employment as a proxy for economic activity. The monthly March and September variables offset, in part, the shoulder season variable. Since weather and economic activity are accounted for by other variables:

> i. What is the rationale and purpose of the March and September binary variables in addition to the "shoulder season" variable?
>
> ii. What, in the view of EnWin Utilities or Elenchus, are the March and September binary variables, in combination with the other variables in the GS < 50 kW model, measuring?

---

Response:

a) The time trend variable may be reflecting a number of potential consumption trends including: conservation activities outside of the CFF, improved building efficiency, and an increase in the proportion of customers that operate less energy-consuming businesses and other organizations. The time trend reflects a gradual decline in consumption that is not explained by the other variables.

b)

i. Including the shoulder variable, which includes March and September, and the March and September variables is equivalent to including a shoulder variable that does not include March and September along with the March and September variables. In the case of September, including the individual variable and its inclusion in the shoulder variable mostly offset. The coefficient of the individual March variable partially offsets the shoulder variable. The purpose is to reflect the actual lower consumption observed in those months that are not explained by weather, or other, variables.

ii. The shoulder variable accounts for decreased consumption in months that do not require a significant amount of weather-related consumption. The magnitude of the shoulder coefficient depends on the range in temperature customers within the class are comfortable with before requiring heating or cooling. The use of alternate HDD and CDD thresholds would reduce reliance on shoulder and month-specific variables.

## 3 - OEB Staff - 78

Reference:

Exhibit 3, Attachment 3-A, Pages 11-14

Preamble:

Elenchus documents the load forecast regression model for the GS > 50 kW class on pages 11-14 of its report.

Question:

a) Elenchus notes that a linear trend variable is included, which begins with a value of 1 in January 2008 and increasing to 120 for December 2017. The estimated coefficient is negative and statistically significant. Since the historical consumption data are adjusted to add back CDM, as measured by the OPA/IESO, over the period, what, in the view of EnWin Utilities or Elenchus, is this trend variable actually measuring?

b) The model includes variables for both the number of days in each month as well as the number of business days (PEAK_Days) in each month. Coefficients for both variables are positive and statistically significant. The customers in this class are generally medium-sized businesses. What is the rationale for having both variables in the model, and what customer energy demand phenomena are these two variables jointly measuring, in the view of EnWin Utilities or Elenchus?

c) Elenchus notes that binary variables for the months of April, June, August, September and October were "much more statistically significant" than seasonal shoulder variables. The April binary variable coefficient is negative, indicating that the model would over-predict consumption for that month in its absence. The coefficients for June, August, September and October are all positive, indicating that the model would under-predict consumption in each month in the absence of that variable. The model includes variables for HDD and CDD and for Ontario GDP. The absence of binary variables for the months of May and July suggest that, otherwise, the model including weather and economic variables reasonably predicts consumption in these months, all else being equal.

i. Elenchus thus includes separate binary variables for 5 out of the 12 months in the year. What is the rationale for including so many monthly binary variables?

ii. Since the model also includes weather and economic activity variables, what, in the view of EnWin Utilities or Elenchus, drivers of energy demand in this class are being proxied by these monthly binary variables?

iii. The Durbin-Watson statistic for this model is 1.02, indicating likely serial correlation of the monthly residual errors. Has Elenchus assessed the reason for this serial correlation? Is it related to the inclusion of these monthly binary variables?

---

Response:

a) The time trend variable may be reflecting a number of potential consumption trends including: conservation activities outside of the CFF, improved building efficiency, and an increase in the proportion of customers that operate less energy-consuming businesses. The time trend reflects a gradual decline in consumption that is not explained by the other variables.

b) Including both month days and peak days reflects the observation that consumption depends on the number of days in a month, but also that there is more consumption in months with more non-holiday weekdays. In Elenchus' opinion it is reasonable to assume GS > 50 kW consumption would be higher on days generally considered work days.

c) Elenchus notes that in the updated forecast the October variable has been excluded.
   i. In selecting monthly binary variables Elenchus weighs the preference for fewer individual month variables with the observations of the actual data that cannot be explained by other variables. Forecasts without including these variables produced weaker results, particularly for the months that have binary variables included. As the monthly deviations from otherwise expected consumption were generally consistent from year to year, an assumption was made that these variances would continue into the future.
   ii. The drivers of energy demand in those months could be explained by Windsor-specific characteristics and factors specific to the entities that are GS > 50 kW customers. The economic variable used in the regression, Ontario GDP, is only available annually so month-by-month variation in economic activity isn't reflected in that variable.
   iii. The Durbin-Watson statistic is higher in the updated model but it is still substantially below 2. The low DW statistic is likely partially due to the high number of monthly binary variables combined with the 18°C HDD and CDD thresholds, though economic activity also likely has an impact. HDD and CDD at the margin (close to 18°C) has a lower impact on consumption than more extreme temperatures. This would likely be improved with alternate HDD and

CDD thresholds.

## 3 - OEB Staff - 79

Reference:

Exhibit 3/Attachment 3-A, Pages 11-16

Preamble:

Elenchus documents the load forecast regression model for the Intermediate Class on pages 14-16 of its report.

Question:

a) Elenchus notes that a linear trend variable is included, which begins with a value of 1 in January 2008 and increasing to 120 for December 2017. The estimated coefficient is negative and statistically significant. Since the historical consumption data are adjusted to add back CDM, as measured by the OPA/IESO, over the period, what, in the view of EnWin Utilities or Elenchus, what is this trend variable actually measuring?

b) Elenchus states that HDD and CDD were not found to be statistically significant explanatory variables for this class. However, for the GS 50-2999 kW that EnWin Utilities is proposing to merge this class, HDD and CDD were found to be statistically significant. There are significant other differences in the variables found to be significant for the models for the two classes.

i. Why did EnWin Utilities not have its consultant develop the load forecast based on the proposed customer class?

ii. If the drivers of demand are as different between these two existing classes as the estimated load forecast models suggest, why does EnWin Utilities consider that its proposed class merger is appropriate?

iii. Assuming that the proposed class merger is appropriate, please provide EnWin Utilities' basis for believing that, given the differences in the two estimated models, adding the load forecasts for these two classes provides a reasonable test year load forecast for the merged class, and where the associated merged billing determinants will be used to establish the base rates to recover the class revenue requirement for the merged class?

Response:

a) The time trend variable may be reflecting a number of potential consumption trends including conservation activities outside of the CFF and the economic conditions of the three customers within the class. Since there are only three customers, consumption will be disproportionately influenced by economic factors of the industries of those three customers that may not be reflected in the economic condition of the economy as a whole.

b)

i) The load forecast was developed prior to the decision to merge the classes. Elenchus confirmed that merging forecast consumption of the two classes was reasonable.

ii) The specific drivers of consumption for three customers (those in the existing Intermediate class) may be different from the identified drivers of consumption among a larger group of customers (those in the existing GS > 50 class). ENWIN believes the customers in the Intermediate rate class are sufficiently similar to other customers in the existing GS > 50 rate class to warrant consolidation of the rate classes.

iii) Please see part b) i) above.

## 3 - OEB Staff - 80

Reference:

Exhibit 3, Attachment 3-A, Page 21 EnWin_2017_Load_Forecast_Model_20190517.xls, Sheet Employment

Preamble:

On page 21 of its report, under Section 3.3 Economic Forecast, Elenchus states:

GDP and employment forecasts are based on the mean forecasts of four major Canadian banks, RBC, TD, Scotiabank and BMO, as of October 2018. Forecast growth rates in 2020 were available only from TD and Scotiabank at this time. Average forecast rates are applied to the most recent GDP and Labour Force Survey data available from Statistics Canada.

On Sheet Employment, in cells F1 to K13, Elenchus provides the following data:

| FTE | BMO | TD | Scotia | RBC | Average |
|---|---|---|---|---|---|
| Report Date | 2-Nov-2018 | 18-Sep-2018 | 15-Oct-2018 | 12-Sep-2018 | |
| 2018 | 1.40% | 1.40% | 1.50% | 1.40% | 1.43% |
| 2019 | 1.30% | 0.60% | 1.10% | 0.60% | 0.90% |
| 2020 | | 0.50% | 0.90% | | 0.70% |
| GDP | | | | | |
| 2017 | 2.80% | | 2.80% | 2.70% | |
| 2018 | 2.20% | 2.20% | 2.10% | 2.00% | 2.13% |
| 2019 | 1.80% | 2.20% | 2.10% | 1.90% | 2.00% |
| 2020 | | 1.70% | 1.60% | | 1.65% |

Latest as of November 6th, 2018

Question:

a) Please provide the definitions of FTE and GDP. In particular, are these forecasts national, for Ontario, or for the Windsor Census Metropolitan Area?

b) Please provide the source documents used for the economic forecast.

c) Please provide further explanation on how Elenchus used the forecasted growth rates to forecast the employment or economic data past October 2018.

Response:

a) Full-Time Equivalent (FTE) is a measure of employment adjusted for part-time and seasonal work. Examples of 1 FTE include: one full-time job held for one year, two full-time jobs held for 6 months, or two part-time (half-day) jobs held for one year. The model includes two FTE variables, Ont_Emp, which is the number of FTEs in Ontario, and Windsor_FTE, which is the number of FTEs within the Windsor CMA, as per Statistics Canada (StatCan Table 14-10-0294-01). GDP is Ontario GDP in $2012 as per Statistics Canada (StatCan Table 36-10-0402-01). Since the original forecast was filed Statistics Canada rebased these variables. In the updated forecast, 2018 figures are scaled to be consistent with the original StatCan figures.

b) Please see Staff-80 Attachment 1.

c) The major banks (TD, Scotiabank, RBC, BMO, and occasionally CIBC) periodically provide provincial forecasts of real GDP and employment growth (among other statistics), by year for the upcoming 2 to 3 years. The simple average of forecast growth rates for a particular measure and year is calculated and applied to the latest historic monthly data. For example, the average 2019 forecast employment growth rate is applied to actual January 2018 FTEs to forecast January 2019 FTEs. This method takes into account seasonal variations in employment. GDP is provided annually so the average 2019 forecast real GDP growth rate is applied to 2018 GDP to forecast 2019 GDP. The forecast growth rates are for Ontario; Windsor-specific forecasts are not available.

# BMO Forecast

https://economics.bmo.com/en/publications/historical/3ca51458-6ee6-4284-9aa7-3722e45822a5/

# Provincial Monitor

BMO Capital Markets
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**An update on provincial economic and fiscal matters** **Spring 2019**

## Flattening Economic Landscape

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The Canadian economy slowed significantly at the turn of the year, alongside weaker global activity, low oil prices, softer consumer and housing activity, and a pullback in business investment. Real GDP growth is currently pegged at less than 1% annualized in each of 2018Q4 and 2019Q1, with full-year 2019 growth expected to soften further to 1.4%, from 1.8% in 2018. Across the country, convergence remains a major theme, with most provinces seeing growth settle in around expected longer-run norms. In fact, the variability of 2018 growth among the provinces was near the lowest in at least 25 years, and our current forecast expects an even tighter spread this year.

**British Columbia** is expected to be at the front of the pack, even though growth is projected to slow to 1.8%, after cooling meaningfully last year. A downdraft in housing-related activity and consumer spending will likely pull the province down after growth above 3% during the 2014-to-2017 period. That said, activity should get a boost in 2020 as a major LNG project ramps up. **Alberta's** real GDP growth is expected to slow in part because of mandated oil production cuts that pulled 325k bpd offline in January. While curbs are gradually easing, 2019 output growth will be depressed. More broadly, capital spending, housing and consumer activity set a still-sluggish backdrop for the province. The recent upward move in oil prices (for both WTI and WCS), however, should support income and confidence this year. **Saskatchewan** looks to be relatively stagnant as well around the 1% range, while **Manitoba** should continue its steady performance, expected at 1.5% this year.

**Ontario** and **Quebec** have decelerated after strong runs. Growth was 2.2% and 2.5% in these provinces, respectively, last year, down from 2.8% each in 2017. Similarly, both are expected to fade further to 1.6% this year. In Ontario, the correction in housing prices and activity is working its way through the economy, but a sharp

### Canada

| | |
|---|---|
| Population: | 36,964,000 |
| Area: | 9,984,670 km$^2$ |
| GDP/Capita: | $57,900 |
| Capital: | Ottawa |
| Party in Power: | Liberals |
| Prime Minister: | Rt. Hon. Justin Trudeau |
| Finance Minister: | Hon. Bill Morneau |

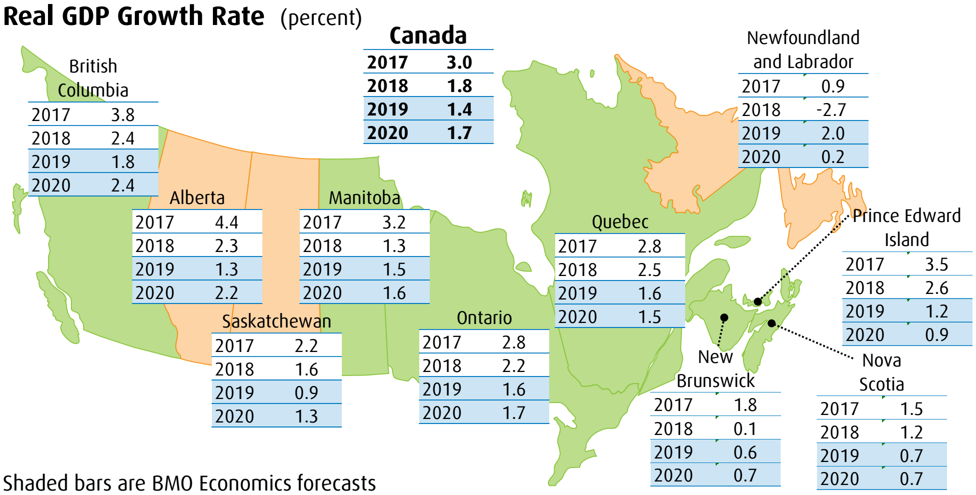
**Legislative Seats:**

| | |
|---|---|
| Liberals | 177 |
| Conservatives | 97 |
| NDP | 41 |
| Bloc Québécois | 10 |
| Green | 2 |
| Ind./Other | 9 |

Next election by October 21, 2019

### Provincial GDP

**Real GDP Growth Rate** (percent)




Shaded bars are BMO Economics forecasts

pullback in longer-term interest rates (and presumably mortgage rates) should help stabilize the market in the spring. Underlying demographic and job market fundamentals remain very supportive as well. Meantime, the provincial government has begun a more pro-business policy tack that could support confidence. In Quebec, housing market activity is strong (especially in Montreal), in contrast to many other major markets in Canada. However, consumer spending and business investment have cooled after very strong runs that peaked in late-2017.

Finally, a population boost has helped lift growth in much of **Atlantic Canada** well above potential over the past few years. While that could persist into 2019, we believe the process of gradually returning to trend will play out in this part of the country as well. One challenge will be retaining recent immigrants in a relatively weak (albeit tightening) labour market, which would buck the trend of population flows to stronger regional economies. Some provinces in the region are also starting to feel a hangover after a number of major private- and public-sector capital spending projects reached completion.

## Government Finances: Budget Season Recap

Nine provinces have tabled their FY19/20 budget or a meaningful fiscal update by the time of publication (full post-election budgets pending from Alberta and PEI). Assuming the fiscal year plays out as forecast, the majority of provinces (six or more) will post balanced budgets for the first time since FY07/08. The convergence theme is playing out on the fiscal front as well, with previously strong credits in oil-producing provinces backtracking, while Quebec and parts of Atlantic Canada are seeing their debt burdens shrink. Here is a budget recap:

The **Province of British Columbia** is projecting a $274 million surplus for FY19/20 (0.1% of GDP), which would mark the seventh consecutive year in the black. A $500 million forecast allowance is in place, along with $750 million for spending contingencies, providing plenty of wiggle room for the upcoming fiscal year, as is the norm for this province. Small surpluses extend over the three-year forecast horizon, but taxpayer-supported debt has begun to rise as a share of GDP, thanks to a hefty capital spending program. From a policy perspective, this budget made much less of a splash than that of a year ago; instead, focusing modest new spending on priority areas such as clean energy and childcare.

The **Province of Alberta** projected a $6.9 bln deficit for FY18/19 in a pre-election fiscal update, improved from the prior estimate ($7.5 bln) and the original budget plan ($8.8 bln). The improvement comes alongside higher WTI prices and a tighter WCS differential. We await a first budget from the new government.

The **Province of Saskatchewan** is projecting a small $34 million surplus for FY19/20, or negligible as a share of GDP. That is improved from the $380 million deficit now expected for FY18/19. Recall that this new fiscal year marks the third in the government's ongoing plan to balance the books, so that promise appears on track at this point. Of course, Saskatchewan is very much at the mercy of oil prices, and recent gains in WTI and Canadian prices have helped the cause—the Province continues to forecast without a contingency, a practice that started last year. That said, the price and currency assumptions are perfectly reasonable, though not overly

### Fiscal Summary

FY19/20

| | Budget Balance ($ mlns) | % of GDP | Net Debt (% of GDP) |
|---|---|---|---|
| BC | 274 | 0.1 | 15.0 |
| AB | (7,912) | (2.2) | 10.7 |
| SK | 34 | 0.0 | 15.1 |
| MB | (360) | (0.5) | 34.7 |
| ON | (10,300) | (1.2) | 40.7 |
| QC | 2,504 | 0.6 | 38.8 |
| NB | 23 | 0.1 | 37.0 |
| NS | 34 | 0.1 | 33.8 |
| PE | 13 | 0.2 | 32.4 |
| NL | (575)* | (1.6) | 39.1 |
| **Total** | **(16,266)** | **(0.7)** | **30.3** |

| | S&P | Moody's | DBRS |
|---|---|---|---|
| BC | AAA | Aaa | AA (high) |
| AB | A+ | Aa1[2] | AA[2] |
| SK | AA | Aaa | AA |
| MB | A+ | Aa2 | A (high) |
| ON | A+ | Aa3 | AA (low) |
| QC | AA- | Aa2 | A (high) |
| NB | A+ | Aa2 | A (high)[2] |
| NS | AA- | Aa2 | A (high) |
| PE | A | Aa2 | A (low) |
| NL | A | Aa3[2] | A (low) |

Source: Provinces, BMO Capital Markets, S&P, Moody's, DBRS ( ) = deficit
[1] pos. outlook [2] neg. outlook
*Excludes Atlantic Accord revenue

conservative. Net debt will dip as a share of GDP, to 14.7% in FY19/20, after rising steadily in recent years.

The **Province of Manitoba** is projecting a $360 million summary budget deficit in FY19/20, slightly improved from the $470 million now expected for FY18/19. That weighs in at less than 1% of GDP, and remains on a clear improving path since bottoming at more than $800 million in 2015. The Province continues to set a gradual track toward balance, with a small ($28 million, or effectively balanced) deficit remaining by FY22/23. Indeed, the full path of the budget balance remains little-changed from that set a year ago. The big difference is that Manitoba is cutting the provincial sales tax by 1 ppt, as long promised, and the revenue losses are offset by gains elsewhere, including higher federal transfers. Net debt is also expected to level off at 34.7% of GDP, after rising steadily for the past decade—the ratio was only 24% coming out of the financial crisis.

The **Province of Ontario** is projecting a $10.3 billion deficit in FY19/20 (1.2% of GDP), in a highly-anticipated detail of how the fiscal path might look under the new government. This follows a $11.7 billion shortfall now expected for FY18/19, down from the $13.5 billion estimated in the latest update and $14.5 billion in the initial post-election report—we've suspected all along that the bar was initially set low, and progress has already been made. The Province expects the deficit to shrink gradually before returning to balance in FY23/24, which is largely consistent with pre-budget messaging. In the meantime, net debt will edge up, peaking at 40.7% of GDP in FY19/20 and FY20/21. From a policy perspective, this budget rolled out some more election promises, including tax relief worth $2.2 billion in FY19/20. Meantime, the government pledges to crack down on program spending through the forecast horizon—this is a marked shift in priorities from recent years.

The **Province of Quebec** is projecting a sixth consecutive surplus in FY19/20, while delivering another helping of policy goodies and spending increases. Before transfers to the Generations Fund (for debt reduction), the surplus is pegged at $2.5 billion (0.6% of GDP), down from a larger-than-expected $5.6 billion now estimated for

Table 1

**Provincial Credit Report Card** (as of May 13, 2019)

| | Budget Plan | | Net Debt | | Taxes | | Economy | | **Overall Grade** | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Level | Progress | Level | Progress | Relative | Progress | Current | Progress | **Current** | **Progress** |
| British Columbia | A– | — | A– | — | A | ↓ | B+ | — | **A-** | **—** |
| Alberta | D | — | A | ↓ | A+ | ↓ | B- | — | **B** | **↓** |
| Saskatchewan | B | ↑ | A– | ↓ | A– | ↓ | C+ | — | **B+** | **—** |
| Manitoba | C+ | ↑ | C+ | ↓ | B | ↑ | B | — | **B–** | **—** |
| Ontario | C- | ↓ | C– | ↓ | B+ | ↑ | B+ | — | **B–** | **—** |
| Quebec | A | — | C | ↑ | D+ | ↑ | B+ | — | **B–** | **↑** |
| New Brunswick | B | — | C | ↑ | D+ | — | C+ | — | **C** | **—** |
| Nova Scotia | A– | — | C+ | ↑ | D | ↑ | C+ | — | **C+** | **↑** |
| Prince Edward Island | B | — | C+ | ↑ | D | — | B | — | **C+** | **—** |
| Newfoundland & Labrador | D | — | C- | — | D | ↓ | D | — | **D** | — |

Levels: A+ = Very Strong, A = Strong, B = Neutral, C = Weak, D = Very Weak.
Progress: Current and expected improvement (↑) or deterioration (↓), past through next fiscal year

Source: BMO Economics

FY18/19. Surpluses in the $2.5-to-$4 billion range persist through the forecast horizon. Meantime, net debt continues to decline as a share of GDP, pegged at 38.8% in FY19/20, down from more than 50% six years ago. And, on a relative basis, the move below Ontario (budget pending) has been well documented. This year's budget built on a host of measures introduced in the Fall fiscal update, which included accelerated CCA allowances and an enhanced family allowance (for those with children). There were $2.3 billion worth of new measures outlined for FY19/20—much of that flows through the spending channel, but $271 million will go back to Quebecers (rising above $400 million the following year).

The **Province of New Brunswick** is projecting a $23 million surplus for FY19/20. That follows a small $4.5 million surplus expected for FY18/19 (originally estimated to be a $188.7 mln deficit), and would mark the second straight year in the black. That is a nice improvement for a province that has grappled with deficits for years. Looking ahead, the Province continues to expect surpluses through FY22/23, while net debt will drift lower as a share of GDP. The drop in debt will, in fact, be the first such move in over a decade.

The **Province of Nova Scotia** is projecting a $33.6 million surplus in FY19/20 (0.1% of GDP), roughly in-line with the $28.4 million now expected in FY18/19 (the latter was little changed during the course of the fiscal year). That would mark the fourth straight year in the black as the Province continues to operate within its means. Nova Scotia projects small surpluses through FY22/23, with the cumulative total about in-line with that projected a year ago. At the same time, net debt will continue to gradually fall as a share of GDP, down to 33.8% this fiscal year, the sixth consecutive year that the burden has fallen. There were few major new policy measures in this budget, with the Province directing some new spending to priority areas such as healthcare.

The **Province of Newfoundland & Labrador** is projecting a hefty $1.9 billion surplus in FY19/20 (more than 5% of GDP), fully on the back of an accounting move that books new future Atlantic Accord revenues in the current fiscal year. Recall that the Atlantic Accord Review will see $2.5 billion flow to the Province (with no restrictions on use) by 2056, with most of it front-end loaded by 2030. Excluding this impact, the underlying deficit sits at $575 million, a touch wider than the $522 million now expected for FY18/19. Looking ahead, the Province expects the deficit to widen next fiscal year, before gradually returning to balance in FY22/23, a timeline that is unchanged from that laid out a year ago. Net debt is pegged at just under 40% of GDP this fiscal year, down from 45% in FY18/19—the discounted future Atlantic Accord revenue stream reduces net debt today.

## British Columbia

**British Columbia's economy is moderating** along with most of Canada, with real GDP growth expected at 1.8% this year, down from 2.4% in 2018. This is a marked downshift from average growth of 3.2% in the four years through 2017. Growth is expected to pick back up next year when the $40 billion **LNG Canada** project breaks more significant ground. Pipeline construction from Dawson to Kitimat will begin this year, and plant construction is expected to peak around 2021 with roughly 10,000 jobs created, providing steady support to growth.

Residential investment, however, continues to fade as the **housing market** correction is ongoing, particularly in Vancouver. This is the result of less speculation and foreign investment, prior Bank of Canada rate hikes and stricter OSFI mortgage-qualification rules. Sales in Vancouver are running at roughly half the 10-year average, and prices for both condos and single-detached homes are still falling. Since peaking in June 2018, the benchmark price is down 8.5%, or more than 10% for single-detached homes.

The **labour market** remains solid, with employment growth rebounding to above 3% y/y. But, because of a sharp increase in the labour force, the jobless rate has held steady at just under 5%—still a low rate. International immigration remains high, while relatively strong economic prospects had been drawing in **migrants** from other provinces—the latter trend faded in through 2018, with limited housing availability one possible reason.

The Province of British Columbia is projecting a **$274 million surplus for FY19/20** (0.1% of GDP), which would mark the seventh consecutive year in the black. There were few major policy initiatives in this year's budget.

### British Columbia

Population: 4,992,000
GDP/Capita: $56,800
Party in Power: NDP
Premier: Hon. John Horgan
Finance Minister: Hon. Carole James

Legislative Seats:

| | |
|---|---|
| Liberals | 42 |
| NDP | 41 |
| Green | 3 |
| Independent | 1 |

Coalition government since May, 2017

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 2.4 | 1.8 | 2.4 |
| Employment | (% chng) | 1.1 | 2.3 | 1.7 |
| Jobless Rate | (%) | 4.7 | 4.7 | 4.5 |
| Housing Starts | (000s) | 40.9 | 40.5 | 35.0 |
| Cons. Prices | (% chng) | 2.7 | 2.3 | 2.3 |
| **Fiscal Situation** | | FY18/19 | | FY19/20 |
| Balance | (C$ mlns) | 374 | | 274 |
| | (% of GDP) | 0.1 | | 0.1 |
| Net Debt | (C$ mlns) | 43,591 | | 46,282 |
| | (% of GDP) | 14.8 | | 15.0 |

Shading: forecast [1] 2018 : by industry

## Alberta

**Alberta's economy remains sluggish** despite an improved oil price backdrop. Real GDP growth likely slowed to 1.3% this year from 2.3% in 2018, as mandated **oil production cuts** weight on output. In an effort to ease the supply bottleneck, the Province mandated a 325k bpd cut in January, which has already begun to be gradually rolled back. The good news is that that WTI prices are firm, and the WCS differential has tightened sharply. Longer term, with oilsands production still on the rise and as past projects/expansions reach completion, limited **pipeline capacity** will remain a pressing issue. New capital investment in the sector is expected to remain limited.

The **housing market** is still weak, with prices in Edmonton and Calgary still drifting lower—Calgary's benchmark price is down 10% from the 2015 peak, and 5% in the past year. Housing starts have found a footing, though well down from pre-shock levels. **Commercial real estate** also remains awash in supply with vacancy rates topping 25% in Calgary's downtown office segment.

The **labour market** is steady, with employment growth up slightly from year-ago levels. The jobless rate, however, is stuck just under the 7% level, which is still historically high for Alberta and well above the national average.

Albertans voted in a **new government** on April 16th, with the United Conservative Party earning a strong majority mandate. While much of this election was fought over pipelines and related rhetoric, a big differentiating factor for the UCP was a pledge to cut the corporate income tax rate by 4 ppts and repeal the carbon tax. Spending restraint would balance the budget a year earlier than currently planned, in FY22/23.

### Alberta

Population: 4,307,000
GDP/Capita: $79,300
Party in Power: United Conservative Party
Premier: Hon. Jason Kenney
Finance Minister: Hon. Travis Toews

Legislative Seats:

| | |
|---|---|
| UCP | 63 |
| NDP | 24 |

Majority government since May, 2019

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 2.3 | 1.3 | 2.2 |
| Employment | (% chng) | 1.9 | 0.4 | 0.9 |
| Jobless Rate | (%) | 6.6 | 6.7 | 6.6 |
| Housing Starts | (000s) | 26.3 | 25.5 | 30.0 |
| Cons. Prices | (% chng) | 2.5 | 2.1 | 2.0 |
| **Fiscal Situation** | | FY18/19 | | FY19/20 |
| Balance | (C$ mlns) | -6,930 | | -7,912 |
| | (% of GDP) | -2.0 | | -2.2 |
| Net Debt | (C$ mlns) | 28,127 | | 37,700 |
| | (% of GDP) | 8.1 | | 10.7 |

Shading: forecast [1] 2018 : by industry

## Saskatchewan

**Saskatchewan's economy remains subdued**, as the effect of the oil price downturn lingers. Real GDP is expected to advance a moderate 0.9% this year, underperforming the national average for a sixth straight year. Growth is expected to remain subdued at 1.3% next year.

The **oil sector** has been retrenching, but the Province expects relatively stable production over the near term. Capital investment, however, looks to be down this year. **Potash** production is rising at a steady clip, but **trade tensions** with China have added an element of risk in the farm sector (particularly for canola).

**Labour market** momentum has improved recently, with service-sector jobs lifting total employment after a prolonged period of stagnation. The jobless rate was down to 5.4% in April after peaking at 7% just over two years ago. **Population growth** continues to moderate, to 1% y/y from 1.6% as recently as four years ago—the province is again losing migrants to other regions, which has held back labour force growth.

With slower demographic demand, **housing starts** have fallen and the resale market remains weak. Starts are currently running at a 15-year low as supply from the prior boom is still getting absorbed. **Home prices** continue to drift steadily lower in Regina and Saskatoon. Meantime, the 10 months' of supply on the resale market province-wide is the biggest overhang in at least 15 years—as such, price weakness will likely continue.

The Province of Saskatchewan is projecting a small **$34 million surplus for FY19/20**, or negligible as a share of GDP. That is improved from the $380 million deficit now expected for FY18/19. Recall that this new fiscal year marks the third in the government's ongoing plan to balance the books.

### Saskatchewan

Population: 1,162,000
GDP/Capita: $68,700
Party in Power: Saskatchewan Party
Premier: Hon. Scott Moe
Finance Minister: Hon. Donna Harpauer

Legislative Seats:
Sask. Party 48
NDP 13

Next election by: November, 2020

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 1.6 | 0.9 | 1.3 |
| Employment | (% chng) | 0.5 | 1.4 | 0.4 |
| Jobless Rate | (%) | 6.1 | 5.3 | 5.2 |
| Housing Starts | (000s) | 3.6 | 3.0 | 3.5 |
| Cons. Prices | (% chng) | 2.3 | 1.8 | 2.0 |
| **Fiscal Situation** | | FY18/19 | | FY19/20 |
| Balance | (C$ mlns) | -380 | | 34 |
| | (% of GDP) | -0.5 | | 0.0 |
| Net Debt | (C$ mlns) | 12,132 | | 12,648 |
| | (% of GDP) | 14.7 | | 15.1 |

Shading: forecast [1] 2018 : by industry

## Manitoba

**Manitoba continues to grow at a steady pace**, with real GDP expected to rise 1.5% this year, up slightly from 1.3% in 2018. Manitoba's diverse manufacturing base and sturdy service sector continue to churn out some of the steadiest growth in Canada, which is often the norm for this province.

**Manufacturing** has had a reasonable run since 2010, and should continue to benefit from sturdy U.S. demand and USMCA clarity—though the latter still needs ratification. That said, Midwest factory activity has softened over the past year.

The **labour market** is sturdy, with employment growth trending around 1.3% when smoothing out data volatility. The jobless rate is bouncing around 5.5%, roughly in-line with the national average, with little deviation in recent years highlighting the province's stability. **Housing market** activity should remain stable, with sales and price growth both modest, supported by solid population growth and favourable affordability. Indeed, demographic demand supported a strong run in housing stats through early-2018, but that momentum has begun to level off.

The Province of Manitoba is projecting a **$360 million summary budget deficit** in FY19/20, slightly improved from the $470 million now expected for FY18/19. That weighs in at less than 1% of GDP, and remains on a clear improving path since bottoming at more than $800 million in 2015. The provincial **sales tax** will be cut by 1 ppt as of July, 2019.

### Manitoba

Population: 1,352,000
GDP/Capita: $53,100
Party in Power: Progressive Conservatives
Premier: Hon. Brian Pallister
Finance Minister: Hon. Scott Fielding

Legislative Seats:
PC 38
NDP 12
Liberal 4
Independent 3

Next election: October, 2020

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 1.3 | 1.5 | 1.6 |
| Employment | (% chng) | 0.6 | 1.4 | 0.5 |
| Jobless Rate | (%) | 6.0 | 5.2 | 5.3 |
| Housing Starts | (000s) | 7.4 | 6.7 | 6.5 |
| Cons. Prices | (% chng) | 2.5 | 1.9 | 2.1 |
| **Fiscal Situation** | | FY18/19 | | FY19/20 |
| Balance | (C$ mlns) | -470 | | -360 |
| | (% of GDP) | -0.6 | | -0.5 |
| Net Debt | (C$ mlns) | 25,211 | | 26,113 |
| | (% of GDP) | 34.3 | | 34.7 |

Shading: forecast [1] 2018 : by industry

## Ontario

**Ontario's economy has moderated** after a powerful multi-year run. Real GDP is expected to grow 1.6% this year, down from 2.2% in 2018 and an average pace of 2.5% in the four years prior to that. The downshift largely reflects a move back toward potential for the province, with some key sectors, such as housing, coming off the boil.

The **housing market** is stabilizing after a wave of recent policy measures (15% tax on non-resident buyers and OSFI rules), and after five Bank of Canada rate hikes. Toronto detached home prices are down roughly 10% from their peak, but condo prices remain at record levels and vacancies are extremely low. This highlights that, despite measures to cool price growth, fundamental supply/demand conditions are still very supportive. Meantime, markets outside the Greater Golden Horseshoe continue to perform very well.

The **labour market** is solid, with 2.5% y/y job growth in 2019Q1, the strongest in 16 years. The jobless rate, at 6% has held relatively steady over the past year amid surge in the labour force, but the province has been able to churn out enough jobs to absorb the influx. The province drew in a record 215,000 migrants from outside Canada and other provinces in 2018. **Export volumes** are rising at a very modest pace, and longer-term issues remain as relatively high labour and electricity costs continue to pose challenges—many sectors are pushing capacity limits, but have been shy to deploy new investment. That said, **USMCA** clarity, **accelerated CCA** allowances and a business-friendly policy shift should support business confidence and investment.

The Province of Ontario is projecting a **$10.3 billion deficit in FY19/20** (1.2% of GDP), following an $11.7 billion shortfall expected for FY18/19. The Province expects the deficit to shrink gradually before returning to balance in FY23/24, and will focus on reducing real per-capita program spending, while following through on tax-cut promises.

### Ontario

Population: 14,323,000
GDP/Capita: $58,900
Party in Power: PC
Premier: Hon. Doug Ford
Finance Minister: Hon. Victor Fideli

Legislative Seats:

| | |
|---|---|
| PC | 73 |
| NDP | 40 |
| Liberal | 7 |
| Green | 1 |
| Independent | 3 |

Next election: June, 2022

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 2.2 | 1.6 | 1.7 |
| Employment | (% chng) | 1.6 | 2.4 | 1.8 |
| Jobless Rate | (%) | 5.6 | 5.8 | 5.6 |
| Housing Starts | (000s) | 79.4 | 72.5 | 72.0 |
| Cons. Prices | (% chng) | 2.4 | 1.9 | 2.1 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | -11,700 | -10,300 | |
| | (% of GDP) | -1.4 | -1.2 | |
| Net Debt | (C$ mlns) | 343,441 | 359,943 | |
| | (% of GDP) | 40.2 | 40.7 | |

Shading: forecast [1] 2018 : by industry

## Quebec

**Quebec is moderating after its best economic performance** in 15 years. Real GDP is expected to grow 1.6% this year, down from 2.5% in 2018 and 2.8% in 2017. While slowing, this is still a solid growth rate for the province, and overall conditions remain supportive for employment, investment and real estate.

Real **business investment** has softened after rising sharply over the past two years. Confidence was boosted by a stable political backdrop (despite the recent change) and much-improved government finances. **Export** momentum has improved meaningfully, and enters 2019 on solid footing. The **labour market** performance has been solid, with sturdy job growth and a low jobless rate. Indeed, the jobless rate fell to 4.9% in April, the first time on record below the 5% mark.

**Montreal's housing market** is seeing continued momentum, and remains arguably the strongest in Canada—solid demand fundamentals, favourable affordability and a spillover of nonresident investment have all helped. Benchmark prices are running at a solid 6.3% y/y pace, and prices should be able to rise further. **Residential construction** has also been a recent boon for the economy.

The Province of Quebec is projecting a sixth consecutive **surplus in FY19/20**. This year's budget built on a host of measures introduced in the Fall fiscal update, which included accelerated CCA allowances and an enhanced family allowance (for those with children). Measures included a reduction in school tax rates, and a gradual reduction in the additional contribution for daycare.

### Quebec

Population: 8,390,000
GDP/Capita: $49,700
Party in Power: CAQ
Premier: Hon. Francois Legault
Finance Minister: Hon. Eric Girard

Legislative Seats:

| | |
|---|---|
| CAQ | 75 |
| Liberal | 29 |
| QS | 10 |
| PQ | 9 |
| Independent | 2 |

Next election: October, 2022

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 2.5 | 1.6 | 1.5 |
| Employment | (% chng) | 0.9 | 1.6 | 1.4 |
| Jobless Rate | (%) | 5.4 | 5.2 | 5.0 |
| Housing Starts | (000s) | 46.9 | 46.5 | 43.0 |
| Cons. Prices | (% chng) | 1.7 | 1.8 | 1.8 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | 5,606 | 2,504 | |
| | (% of GDP) | 1.3 | 0.6 | |
| Net Debt | (C$ mlns) | 174,095 | 174,699 | |
| | (% of GDP) | 40.0 | 38.8 | |

Shading: forecast [1] 2018 : by industry

## New Brunswick

**The New Brunswick economy has softened after a healthy run,** with real GDP little changed in 2018 after 1.6% average growth in the two years prior. We expect moderate and more trend-like 0.6% growth this year.

**Capital spending** has retrenched recently as some major projects have wound down in the forestry and refining sectors. Risks also persist in the potash sector, while **forestry exports** could be challenged by a peaking (but stable) U.S. housing market.

**Labour market** trends have been sturdy, with employment rising in each of the past two years. The unemployment rate has held roughly steady since mid-2017, but that comes alongside a meaningful jump in the labour force. While the province has seen a near-term boost in population, **demographics** remain a longer-term challenge given an aging population. In the meantime, international immigration and less outflows to other provinces have helped on this front.

The Province of New Brunswick is projecting a **$23 million surplus for FY19/20**. That follows a small $4.5 million surplus expected for FY18/19 (originally estimated to be a $188.7 mln deficit), and would mark the second straight year in the black. That is a nice improvement for a province that has grappled with deficits for years. Looking ahead, the Province continues to expect surpluses through FY22/23, while net debt will drift lower as a share of GDP. The drop in debt will, in fact, be the first such move in over a decade.

### New Brunswick

Population: 770,600
GDP/Capita: $46,100
Party in Power: PC
Premier: Hon. Blaine Higgs
Finance Minister: Hon. Ernie Steeves

Legislative Seats:

| | |
|---|---|
| PC | 22 |
| Liberal | 21 |
| Green Party | 3 |
| People's Alliance | 3 |

Minority gov't since September 2018

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 0.1 | 0.6 | 0.7 |
| Employment | (% chng) | 0.3 | 1.1 | 0.2 |
| Jobless Rate | (%) | 8.0 | 8.0 | 7.7 |
| Housing Starts | (000s) | 2.3 | 2.6 | 2.4 |
| Cons. Prices | (% chng) | 2.2 | 1.8 | 2.1 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | 5 | 23 | |
| | (% of GDP) | 0.0 | 0.1 | |
| Net Debt | (C$ mlns) | 14,105 | 14,056 | |
| | (% of GDP) | 37.8 | 37.0 | |

Shading: forecast [1] 2018 : by industry

## Nova Scotia

**Economic growth looks to moderate in Nova Scotia again this year**, with real GDP likely to run at 0.7%, down from 1.2% in 2018. Growth should hold around this rate through next year given that it roughly marks near-tem potential. Keep in mind that the province has just come off its best three-year run (averaging 1.4%) since emerging from the financial crisis—demographics and nonresidential investment added a boost.

The Halifax Shipyard is now busy with the $25 billion contract to build combat ships for the Royal Canadian Navy (through 2030) well underway. Other major **capital projects,** such as the Nova Centre and Maritime Link, have also supported growth recently, but their contributions have begun to fade—capital spending is expected to fall about 6% this year. **Residential construction** activity has been strong, with the number of units under construction in Halifax at a record high. This is partly in response to **firmer population growth** through two channels: a reversal of outflows previously headed to Alberta, and a big jump in international immigration, as seen across much of the Atlantic region.

**Labour market** momentum has been strong, with employment surging to record levels, up 2.3% from a year ago through April. That pulled the jobless rate down to a record low 6.2% at one point (March). Job growth has been broad, across full- and part-time positions, and in both the goods and services sectors.

The Province of Nova Scotia is projecting a **$33.6 million surplus in FY19/20** (0.1% of GDP), roughly in-line with the $28.4 million now expected in FY18/19. That would mark the fourth straight year in the black as the Province continues to operate within its means. There were few major new policy measures in this budget, with the Province directing some new spending to priority areas such as healthcare..

### Nova Scotia

Population: 960,000
GDP/Capita: $45,400
Party in Power: Liberals
Premier: Hon. Stephen McNeil
Finance Minister: Hon. Karen Casey

Legislative Seats:

| | |
|---|---|
| Liberals | 27 |
| PC | 17 |
| NDP | 6 |
| Vacant | 1 |

Next election by June, 2022

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 1.2 | 0.7 | 0.7 |
| Employment | (% chng) | 1.5 | 2.5 | 0.2 |
| Jobless Rate | (%) | 7.6 | 6.5 | 6.5 |
| Housing Starts | (000s) | 4.9 | 5.5 | 5.0 |
| Cons. Prices | (% chng) | 2.2 | 1.6 | 2.0 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | 28 | 34 | |
| | (% of GDP) | 0.1 | 0.1 | |
| Net Debt | (C$ mlns) | 15,069 | 15,276 | |
| | (% of GDP) | 34.3 | 33.8 | |

Shading: forecast [1] 2018 : by industry

## Prince Edward Island

The **PEI economy has run at a very solid pace**, but real GDP growth will likely moderate to 1.2% this year after averaging 3.0% the prior two years. Sturdy U.S. economic growth and a population boost should continue to offset public-sector restraint, leaving the province to grow roughly at potential over the medium term.

**Exports** are rising at a solid clip, led by transportation equipment, as well as past gains in electronics and electrical equipment. U.S. demand is expected to remain firm, and the Canadian dollar is supportive of **tourism** activity at recent levels.

Public-sector restraint is likely to remain a mild drag on growth in the year ahead. After rising strongly in recent years, **public-sector capital spending** will likely hold relatively steady this year, according to StatCan's survey of intentions.

**Population growth** is running at a very strong 2.1% y/y pace. International immigration has accelerated, and net interprovincial migration has largely levelled off. **Employment** has been a bright spot, rising to a record level in the first quarter. That has helped pull the jobless rate consistently below 10%, after trending in the 10%-to-13% range through much of the cycle to date.

The Province of Prince Edward Island's 2019 budget is pending after the **Progressive Conservatives were elected** to a minority mandate in April. Balanced budgets and falling net debt have been a fixture in recent years.

### Prince Edward Island

Population: 153,200
GDP/Capita: $43,700
Party in Power: PC
Premier: Hon. Dennis King
Finance Minister: TBD

Legislative Seats:
PC 12
Green 8
Liberal 6

Minority government since May, 2019

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | 2.6 | 1.2 | 0.9 |
| Employment | (% chng) | 3.0 | 0.4 | 0.5 |
| Jobless Rate | (%) | 9.4 | 9.3 | 9.0 |
| Housing Starts | (000s) | 1.0 | 0.9 | 0.9 |
| Cons. Prices | (% chng) | 2.3 | 1.2 | 1.8 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | 14 | 13 | |
| | (% of GDP) | 0.2 | 0.2 | |
| Net Debt | (C$ mlns) | 2,239 | 2,232 | |
| | (% of GDP) | 32.5 | 32.4 | |

Shading: forecast [1] 2018 : by industry

## Newfoundland and Labrador

**Newfoundland & Labrador's economy remains mixed**, but the recent strength in oil prices should support income growth. Real GDP is expected to rebound 2.0% this year after a 2.7% decline in 2018, partly the result of temporary factors.

The **oil sector** makes up roughly 20% of provincial GDP and more than 7% of employment—both just slightly smaller than in Alberta. As a result, the recent cycle in oil prices has impacted incomes. Production has faded after peaking in 2007, but Hebron began producing late in 2017, and should support higher output as it ramps up to 150,000 bpd over the coming years. Longer-term potential in the sector is solid, but near-term **capital investment** is facing a lull, with other projects such as Muskrat Falls also winding down. Last year's temporary decline in **iron-ore output** was a drag on GDP growth that should reverse this year.

**Employment** has improved over the past year, but is still about 6% below the 2013 peak. But, because the province hasn't seen the population influx that most of its peers have seen, the jobless rate has fallen to below 12%, down more than 3 ppts since the end of 2017. That said, **retail sales** and **housing** have underperformed since the demographic boost has been absent.

The Province of Newfoundland & Labrador is projecting a hefty **$1.9 billion surplus** in FY19/20 (more than 5% of GDP), fully on the back of an accounting move that books new future Atlantic Accord revenues in the current fiscal year. Recall that the Atlantic Accord Review will see $2.5 billion flow to the Province (with no restrictions on use) by 2056, with most of it front-end loaded by 2030. Excluding this impact, the underlying deficit sits at $575 million, a touch wider than the $522 million now expected for FY18/19. Looking ahead, the Province expects the deficit to widen next fiscal year, before gradually returning to balance in FY22/23.

### Newfoundland & Labrador

Population: 525,400
GDP/Capita: $61,300
Party in Power: Liberals
Premier: Hon. Dwight Ball
Finance Minister: Hon. Tom Osborne

Legislative Seats:
Election pending

Next election: May 16, 2019

| Economic Outlook | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Real GDP[1] | (% chng) | -2.7 | 2.0 | 0.2 |
| Employment | (% chng) | 0.4 | 2.8 | 0.0 |
| Jobless Rate | (%) | 13.8 | 11.6 | 11.6 |
| Housing Starts | (000s) | 1.5 | 1.0 | 1.2 |
| Cons. Prices | (% chng) | 1.7 | 1.3 | 2.0 |
| **Fiscal Situation** | | FY18/19 | FY19/20 | |
| Balance | (C$ mlns) | -522 | -575 | |
| | (% of GDP) | -1.5 | -1.6 | |
| Net Debt | (C$ mlns) | 15,414 | 13,768 | |
| | (% of GDP) | 44.9 | 39.1 | |

Shading: forecast [1] 2018 : by industry

# Provincial Monitor

BMO Capital Markets



## History of Canadian Fiscal Balances

| ($ millions) | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19e | 19/20f |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BC | 73 | (1,812) | (246) | (1,841) | (1,147) | 314 | 1,660 | 810 | 2,727 | 301 | 374 | 274 |
| Alberta | (931) | (476) | (2,262) | (114) | (3,099) | (302) | 1,115 | (6,442) | (10,784) | (8,023) | (6,930) | (7,912) |
| Sask. | 2,968 | (409) | (13) | (105) | 37 | 589 | 62 | (1,520) | (1,218) | (303) | (380) | 34 |
| Manitoba | 449 | (185) | (181) | (1,001) | (560) | (600) | (539) | (932) | (764) | (695) | (470) | (360) |
| Ontario | (6,409) | (19,262) | (17,200) | (15,408) | (10,662) | (11,530) | (11,248) | (5,346) | (2,435) | (3,700) | (11,700) | (10,300) |
| Quebec | (1,258) | (2,940) | (2,390) | (1,788) | (2,515) | (1,703) | 136 | 3,644 | 4,362 | 4,915 | 5,606 | 2,504 |
| NB | (152) | (695) | (617) | (244) | (533) | (600) | (361) | (261) | (117) | 67 | 5 | 23 |
| NS | 26 | (269) | 585 | (259) | (304) | (677) | (144) | (13) | 151 | 230 | 28 | 34 |
| PEI | (31) | (74) | (63) | (84) | (80) | (46) | (20) | (13) | (1) | 1 | 14 | 13 |
| NL | 2,350 | (33) | 594 | 974 | (195) | (389) | (1,006) | (2,206) | (1,148) | (911) | (522) | (575) |
| Provinces | (2,915) | (26,155) | (21,793) | (19,870) | (19,058) | (14,944) | (10,345) | (12,279) | (9,227) | (8,118) | (13,975) | (16,266) |
| Federal | (9,116) | (56,368) | (34,953) | (28,033) | (21,293) | (8,050) | (550) | (2,861) | (18,957) | (18,961) | (14,900) | (19,800) |
| Total | (12,031) | (82,523) | (56,746) | (47,903) | (40,351) | (22,994) | (10,895) | (15,140) | (28,184) | (27,079) | (28,875) | (36,066) |
| (% of GDP) | | | | | | | | | | | | |
| BC | 0.0 | (0.9) | (0.1) | (0.8) | (0.5) | 0.1 | 0.7 | 0.3 | 1.0 | 0.1 | 0.1 | 0.1 |
| Alberta | (0.3) | (0.2) | (0.8) | (0.0) | (1.0) | (0.1) | 0.3 | (2.0) | (3.6) | (2.4) | (2.0) | (2.2) |
| Sask. | 4.4 | (0.7) | (0.0) | (0.1) | 0.0 | 0.7 | 0.1 | (1.9) | (1.6) | (0.4) | (0.5) | 0.0 |
| Manitoba | 0.9 | (0.4) | (0.3) | (1.8) | (0.9) | (1.0) | (0.8) | (1.4) | (1.1) | (1.0) | (0.6) | (0.5) |
| Ontario | (1.1) | (3.2) | (2.7) | (2.3) | (1.6) | (1.7) | (1.5) | (0.7) | (0.3) | (0.4) | (1.4) | (1.2) |
| Quebec | (0.4) | (0.9) | (0.7) | (0.5) | (0.7) | (0.5) | 0.0 | 0.9 | 1.1 | 1.2 | 1.3 | 0.6 |
| NB | (0.5) | (2.4) | (2.0) | (0.8) | (1.7) | (1.9) | (1.1) | (0.8) | (0.3) | 0.2 | 0.0 | 0.1 |
| NS | 0.1 | (0.8) | 1.6 | (0.7) | (0.8) | (1.8) | (0.4) | (0.0) | 0.4 | 0.5 | 0.1 | 0.1 |
| PEI | (0.7) | (1.5) | (1.2) | (1.5) | (1.4) | (0.8) | (0.3) | (0.2) | (0.0) | 0.0 | 0.2 | 0.2 |
| NL | 7.4 | (0.1) | 2.0 | 2.9 | (0.6) | (1.1) | (2.9) | (7.1) | (3.6) | (2.8) | (1.5) | (1.6) |
| Provinces | (0.2) | (1.7) | (1.3) | (1.1) | (1.0) | (0.8) | (0.5) | (0.6) | (0.5) | (0.4) | (0.6) | (0.7) |
| Federal | (0.6) | (3.6) | (2.1) | (1.6) | (1.2) | (0.4) | (0.0) | (0.1) | (0.9) | (0.9) | (0.7) | (0.9) |
| Total | (0.7) | (5.3) | (3.4) | (2.7) | (2.2) | (1.2) | (0.5) | (0.8) | (1.4) | (1.3) | (1.3) | (1.6) |

( ) = deficit e = estimate f = forecast Ontario FY19/20 deficit carried forward pending budget

## Provincial Economic Summary

| | BC | Alberta | Sask. | Manitoba | Ontario | Quebec | NB | NS | PEI | NL | Canada |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Real GDP Growth (chain-weighted : year/year % change) | | | | | | | | | | | |
| 2018 [1] | 2.4 | 2.3 | 1.6 | 1.3 | 2.2 | 2.5 | 0.1 | 1.2 | 2.6 | -2.7 | 1.8 |
| 2019 f | 1.8 | 1.3 | 0.9 | 1.5 | 1.6 | 1.6 | 0.6 | 0.7 | 1.2 | 2.0 | 1.4 |
| 2020 f | 2.4 | 2.2 | 1.3 | 1.6 | 1.7 | 1.5 | 0.7 | 0.7 | 0.9 | 0.2 | 1.7 |
| Employment Growth (year/year % change) | | | | | | | | | | | |
| 2018 | 1.1 | 1.9 | 0.5 | 0.6 | 1.6 | 0.9 | 0.3 | 1.5 | 3.0 | 0.4 | 1.3 |
| 2019 f | 2.3 | 0.4 | 1.4 | 1.4 | 2.4 | 1.6 | 1.1 | 2.5 | 0.4 | 2.8 | 1.9 |
| 2020 f | 1.7 | 0.9 | 0.4 | 0.5 | 1.8 | 1.4 | 0.2 | 0.2 | 0.5 | 0.0 | 1.4 |
| Unemployment Rate (percent) | | | | | | | | | | | |
| 2018 | 4.7 | 6.7 | 6.1 | 6.0 | 5.7 | 5.5 | 8.0 | 7.6 | 9.4 | 13.8 | 5.8 |
| 2019 f | 4.7 | 6.7 | 5.3 | 5.2 | 5.8 | 5.2 | 8.0 | 6.5 | 9.3 | 11.6 | 5.7 |
| 2020 f | 4.5 | 6.6 | 5.2 | 5.3 | 5.6 | 5.0 | 7.7 | 6.5 | 9.0 | 11.6 | 5.6 |
| Housing Starts (thousands) | | | | | | | | | | | |
| 2018 | 40.9 | 26.3 | 3.6 | 7.4 | 79.4 | 46.9 | 2.3 | 4.9 | 1.0 | 1.5 | 214 |
| 2019 f | 40.5 | 25.5 | 3.0 | 6.7 | 72.5 | 46.5 | 2.6 | 5.5 | 0.9 | 1.0 | 205 |
| 2020 f | 35.0 | 30.0 | 3.5 | 6.5 | 72.0 | 43.0 | 2.4 | 5.0 | 0.9 | 1.2 | 200 |
| Consumer Prices (year/year % change) | | | | | | | | | | | |
| 2018 | 2.7 | 2.5 | 2.2 | 2.5 | 2.4 | 1.7 | 2.2 | 2.2 | 2.3 | 1.7 | 2.2 |
| 2019 f | 2.3 | 2.1 | 1.8 | 1.9 | 1.9 | 1.8 | 1.8 | 1.6 | 1.2 | 1.3 | 1.9 |
| 2020 f | 2.3 | 2.0 | 2.0 | 2.1 | 2.1 | 1.8 | 2.1 | 2.0 | 1.8 | 2.0 | 2.1 |

[1] 2018 provincial GDP by industry f = forecast

# Provincial Monitor



## Provincial Economic Indicators

| (3-month m.a. : year/year % change) | BC | Alberta | Sask. | Manitoba | Ontario | Quebec | NB | NS | PEI | NL | Canada |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Retail Sales** | | | | | | | | | | | |
| Dec 18 | -0.5 | 0.3 | -3.7 | 1.3 | 3.5 | 1.1 | -0.1 | -3.1 | -1.0 | -5.0 | 1.2 |
| Jan 19 | 1.4 | 0.5 | -3.6 | -0.7 | 1.9 | 1.1 | -0.1 | -1.5 | -1.3 | -2.6 | 1.0 |
| Feb 19 | 1.3 | 0.2 | -3.0 | 0.9 | 1.7 | 2.7 | 0.7 | 0.6 | -0.3 | -1.5 | 1.4 |
| **Manufacturing Shipments** | | | | | | | | | | | |
| Dec 18 | 3.4 | 5.2 | 7.5 | 3.6 | 4.7 | 6.6 | -33.5 | 3.5 | 20.6 | 8.6 | 4.1 |
| Jan 19 | 2.7 | 0.5 | 5.3 | 4.8 | 2.0 | 5.5 | -32.6 | 4.9 | 14.9 | 0.3 | 1.9 |
| Feb 19 | 2.3 | -0.5 | 2.3 | 1.1 | 0.9 | 5.9 | -25.6 | 3.6 | 16.3 | 6.2 | 1.4 |
| **Exports** | | | | | | | | | | | |
| Jan 19 | 6.7 | -2.6 | 1.8 | 4.8 | 2.3 | 8.6 | -35.3 | 6.7 | 21.9 | 15.7 | 2.0 |
| Feb 19 | 3.8 | -8.0 | -2.9 | 2.2 | 1.9 | 10.2 | -25.3 | 5.9 | 21.0 | 1.6 | 0.0 |
| Mar 19 | 2.1 | -3.4 | -4.1 | 0.2 | 3.0 | 6.0 | -10.3 | 6.4 | 9.6 | 9.3 | 1.0 |
| **Employment Growth** | | | | | | | | | | | |
| Feb 19 | 2.4 | 0.7 | 1.7 | 1.8 | 2.1 | 0.8 | -0.1 | 2.0 | 0.1 | 2.7 | 1.6 |
| Mar 19 | 2.8 | 0.4 | 1.5 | 2.0 | 2.5 | 0.9 | 0.9 | 2.5 | 0.7 | 3.3 | 1.8 |
| Apr 19 | 3.1 | 0.6 | 2.0 | 1.6 | 2.6 | 1.2 | 0.6 | 2.2 | 1.7 | 3.0 | 2.0 |

# TD Forecast

https://economics.td.com/provincial-economic-forecast

TD Economics

# Provincial Economic Forecast

## Economic Growth and Job Markets Diverge in 2019

June 17, 2019

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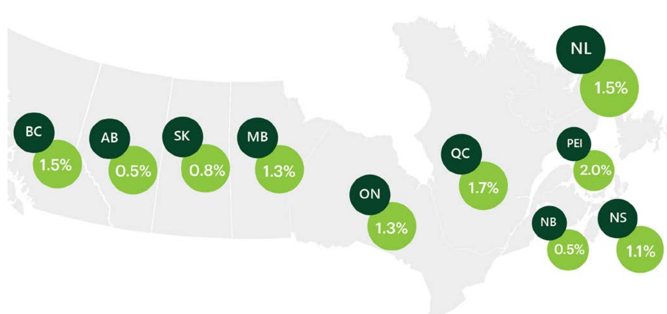
Jump to: BC | AB | SK | MB | ON | QC | NB | NS | PE | NL | Forecast Tables

- As we had anticipated, economic growth in most regions has been gaining some traction of late after a challenging start to the year. For the full year, growth is expected to run from a low of 0.5% in Alberta and New Brunswick to 2% in Prince Edward Island. These modest rates are largely unchanged from our March forecast.
- Underlying this subdued picture for output and spending is surprising strength in job markets. Even with an assumed normalization in hiring trends going forward, job growth forecasts have been upgraded this year in eight of ten provinces, notably in Ontario and British Columbia. Ongoing resilience in job markets, alongside a recent reduction in borrowing rates, is expected to support continued household spending gains from coast to coast over the forecast period.
- B.C.'s economy and job market are still expected to advance this year despite a deep slowdown in housing activity. We look for stabilization in home sales during the second half of 2019, with prices likely to reach a bottom during 2020. Continued solid prospects for non-residential investment should provide some offset to weakness on the residential side.
- Alberta's economy is expected to eke out minimal expansion this year, before recording a slight acceleration in 2020. Mandated oil production curtailment so far this year has yielded stronger bitumen prices. However, business and household spending remain hampered by concerns around medium-term energy investment. Likewise, the Manitoba and Saskatchewan economies are encountering growth-limiting headwinds, notably soft global agriculture conditions and slowing population growth. As these pressures ease next year, growth should pick up closer to trend.
- On the heels of a growth downshift since mid-2018, economic "green shoots" have been evident of late in Ontario and Quebec. Of the two, Quebec would appear to enjoy the growth edge, owing in part to fiscal stimulus and strong housing momentum. Ontario's fiscal picture remains challenging, with government spending restraint set to weigh on its near-term economic performance.
- Growth in the Atlantic region for this year is largely unchanged from our March view. PEI is likely to chalk up another solid year for growth, while Newfoundland & Labrador records an improvement from its tepid 2018 rate. More modest growth performances are expected for New Brunswick and Nova Scotia.

**Provincial Real GDP Growth Forecast (2019)**




Source: TD Economics. Forecast as of June 2019.

For more details on our national forecast see our Quarterly Economic Forecast

## British Columbia

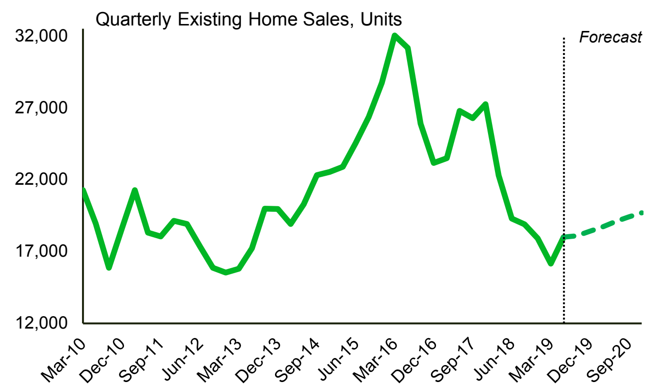
While real GDP growth in B.C. moderated in 2018, the estimated gain of 2.4% outstripped the national average for the fifth straight year. A surge in natural gas output and robust expansion in residential and non-residential construction and transportation & warehousing activity propelled last year's advance. Looking ahead, we anticipate a further slowdown to a below-trend rate in 2019, largely on the back of the recent slump in housing activity. Provided that housing gains some traction in 2020 – as we expect – economic growth should regain some momentum.

The adjustment underway in the province's housing markets to both government policy changes and higher interest rates over the past few years has been sharper and more prolonged than we had anticipated. Declines in resale activity (Chart 1) and average prices accelerated this year, while the market balance in the Greater Vancouver Area has sunken well into buyer's territory. That said, with much of the speculative froth having been removed from the market and interest rate trends recently turning more favourable, sales are likely to begin firming in the second half of the year. Still, some residual softness in home prices and homebuilding is expected to linger into 2020.

A key factor that has helped insulate the economy from the spill-over impacts of declining housing activity is ongoing resilience in labour markets. The province maintains the country's lowest unemployment rate and a historically-high core age participation rate. By any measure, employment in B.C. is growing at an unsustainably rapid clip this year, setting the stage for a significant moderation in 2020.

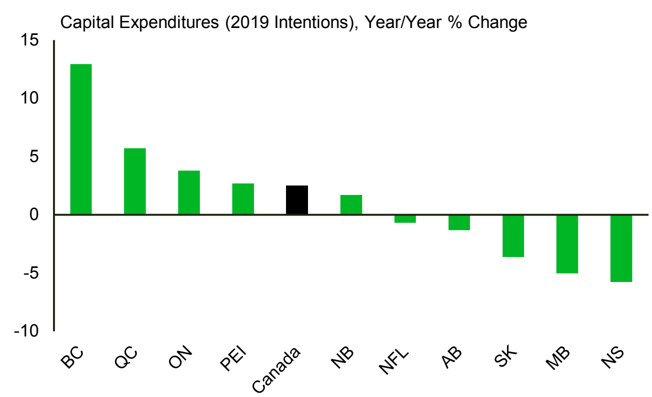
Meanwhile, prospects for engineering and non-residential investment remain bright. As measured by StatCan's Capital and Repair Expenditures Survey, B.C. topped the nation (Chart 2). Large scale projects, including LNG Canada, the associated pipeline will help to sustain non-residential construction going forward. A late-2018 surge in non-residential building permits further confirms this narrative. Additionally, labour market tightness and an absense in spare productive capacity is likely to incentivize investment. But while the outlook for non-residential investment remains strong for the most part, one area of near-term downside risk surrounds the export sector, which is expected to struggle amid weak conditions in the forestry sector, a slowing Chinese economy, and growing trade tensions.

**Chart 1: B.C.'s Resale Market is Expected to Stabilize**




Source: CREA, TD Economics, Forecast by TD Economics as of June 2019

**Chart 2: B.C. Topped the Country for Growth in 2019 Capital Spending Intentions**




Source: Statistics Canada, TD Economics

**British Columbia Economic Forecasts**
[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 2.4 | 1.5 | 2.0 |
| Nominal GDP | 4.7 | 3.5 | 4.4 |
| Employment | 1.1 | 3.1 | 0.8 |
| Unemployment Rate (%) | 4.7 | 4.6 | 4.7 |
| Housing Starts (000's) | 40.9 | 42.1 | 34.9 |
| Existing Home Prices | 0.9 | -7.9 | -0.6 |
| Home Sales | -24.5 | -9.8 | 8.8 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

# Alberta

Alberta's 2019 growth prospects were dealt a severe blow late last year by extreme softness in heavy oil prices. The good news is that the mandated oil output curtailment has secured a sustained improvement in heavy oil prices (Chart 1). Still, investment and spending in the province have been slow to respond (Chart 2). We anticipate a moderate rebound in real GDP growth in 2020, but those gains will likely be narrowly concentrated in oil output, belying continued weakness in the broader economy.

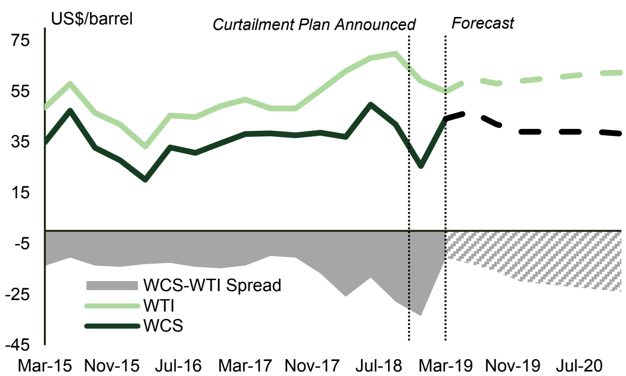
Despite an easing in oil output restrictions in recent months, near-term risks surrounding prices are tilted to the downside. Globally, price benchmarks have weakened since May, reflecting an escalation in trade tensions and oversupply concerns. In response, we have nudged down our 2019 and 2020 WTI price outlook. Within the Alberta oil patch, elevated stockpiles of crude have been slow to work down amid an unexpected softening in exports and crude-by-rail shipments in Q1. Fortunately, exports have shown signs of strengthening, boding well for a rebalancing heading into 2020.

The environment for oilpatch investment is likely to remain challenging. Further regulatory setbacks and a delay to the start-up of operations on Line 3 has only clouded the outlook further. Petroleum and chemical manufacturing remains one area of expansion and provides opportunities for longer-term diversification.

The province's labour markets have weathered the recent growth slump better than expected. At the same time, this year's steady employment picture suggests that any rebound on tap next year will be modest at best. In turn, consumers are likely to remain cautious to spend, while the province's housing markets continue to struggle amid continued excess supply. On the plus side, a bounce back in home resale activity this spring provides some early hints that housing demand is beginning to turn the corner.

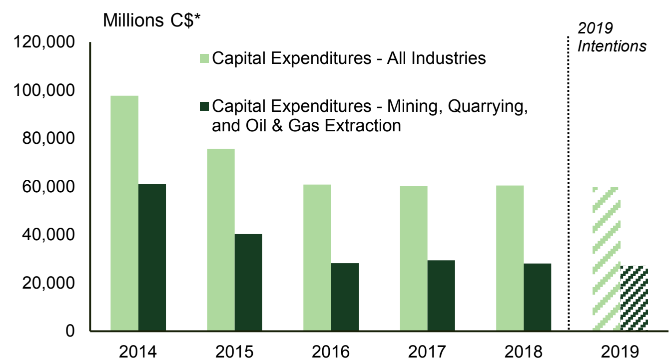
The newly-elected government will table its first budget in the autumn, with a cut to corporate taxes already announced. However, one challenging task will be to make good on its goal to slay the estimated $6.9 billion provincial deficit by FY2022-23, a year earlier than promised by the previous government. A freeze to operating expenses may be on the table since it was implied in the government's election platform.

**Chart 1: Curtailment Supported a Rebound in WCS Prices, but Modest Downside Risk Remains**




Source: Bloomberg, TD Economics, Forecast by TD Economics as of June 2019

**Chart 2: Capital Spending has Remained Virtually Flat in Alberta Since 2016**




Source: Statistics Canada, TD Economics
*Estimates for 2018 are preliminary. Data for 2019 represents spending intentions.

**Alberta Economic Forecasts**

[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 2.0 | 0.5 | 2.1 |
| Nominal GDP | 3.5 | 1.9 | 4.8 |
| Employment | 1.9 | 0.6 | 1.2 |
| Unemployment Rate (%) | 6.6 | 6.8 | 6.7 |
| Housing Starts (000's) | 26.3 | 23.4 | 25.7 |
| Existing Home Prices | -2.4 | -3.3 | 0.0 |
| Home Sales | -7.2 | 2.3 | 10.0 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

## Saskatchewan

After turning in a decent rebound in 2017, growth in Saskatchewan's economy moderated to an estimated 1.6% pace in 2018. Economic growth is expected to downshift further this year, before gaining some modest traction in 2020.

Improved heavy oil pricing so far this year has been supporting cash flows in the oil patch, though recent declines in global benchmarks partly on the back of tariff worries have muted some of the benefits. The province has not experienced the same production constraints as its neighbor to the west. That said, output and investment prospects will continue to be impeded by elevated uncertainty, especially surrounding market access.

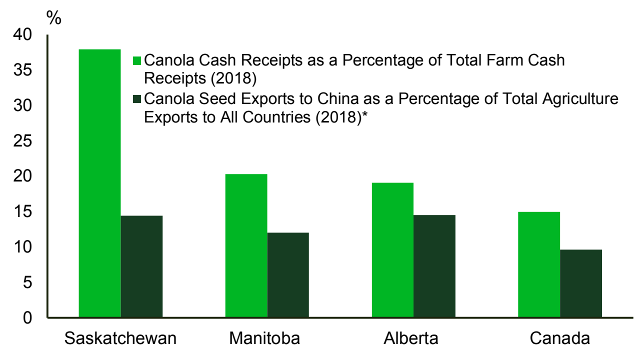
The province's agricultural sector is challenged by a number of headwinds ranging from weak crop pricing to new restrictions on canola seed exports into China (Chart 1). Last year, a surge in farm-related expenses including feed, debt, and energy costs drove a 42% drop in net income. Expense growth is expected to level off this year, but net income will likely remain below its five-year average due to expected softness in farm cash receipts. While crop rotation away from canola can help to mitigate the downside impacts on farm revenue, there are limits to the degree to which rotation can be utilized.

Elsewhere, the uranium industry continues to be challenged by weak global market conditions as well as the impact of the recent indefinite closure of the McArthur River mine. In contrast, the potash industry is enjoying solid momentum this year, with production up more than 7% (ytd) and prices expected to remain steady-to-slightly higher.

An additional bright spot has been the province's labour markets. Job growth is at 2% (ytd), and the unemployment rate has averaged 5.4% so far this year – a substantial improvement relative to the last three years (Chart 2). In turn, this improved employment situation, as well as improved affordability, is expected to support a rebound in home sales in the coming quarters. That said, home building is still expected to remain weak given continued elevated supply.

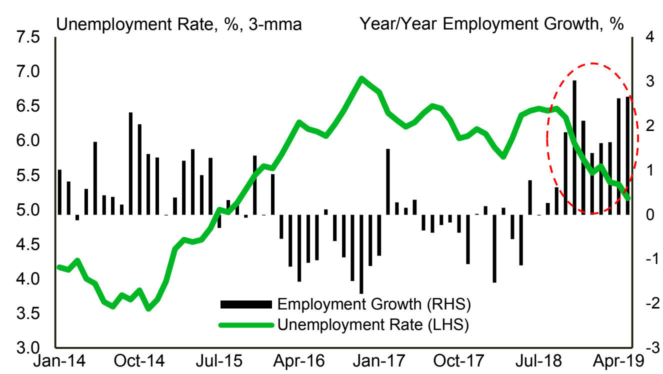
The Saskatchewan government plans to eliminate a $380 million deficit in the current year, a goal that could be challenging given some of the unanticipated softness this year in commodity markets. On the plus side, the Province's still-low net debt-to-GDP ratio continues to provide more flexibility than most of its provincial counterparts.

**Chart 1: Saskatchewan's Agricultural Sector is Exposed to the Subdued Canola Outlook**




Source: Industry Canada, Statistics Canada, TD Economics
*Data is for domestic exports and excludes support activities, forestry, floriculture, and aquaculture products

**Chart 2: Saskatchewan's Labour Market Showing Early Signs of Improvment**




Source: Statistics Canada, TD Economics. Last Data Point May, 2019

| Saskatchewan Economic Forecasts<br>[ Annual average % change, unless otherwise noted ] | | | |
|---|---|---|---|
| | 2018 | 2019 | 2020 |
| Real GDP | 1.5 | 0.8 | 1.2 |
| Nominal GDP | 3.2 | 2.1 | 3.8 |
| Employment | 0.5 | 1.4 | 0.7 |
| Unemployment Rate (%) | 6.1 | 5.5 | 5.8 |
| Housing Starts (000's) | 3.6 | 2.3 | 4.1 |
| Existing Home Prices | -2.3 | -2.0 | -0.2 |
| Home Sales | -7.1 | 7.9 | 6.9 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

## Manitoba

After a robust turnout of around 3% in 2017, Manitoba's economic growth moderated to about half that rate in 2018. Both gains in goods and services production were softer, with the former weighed down by mining industry closures. Meanwhile, services output eased to its slowest pace since at least 1998, clipped by softer retail spending. On the bright side, construction output continued to expand rapidly, boosted by on-going work on the Keeyask power station and the Line 3 Replacement project.

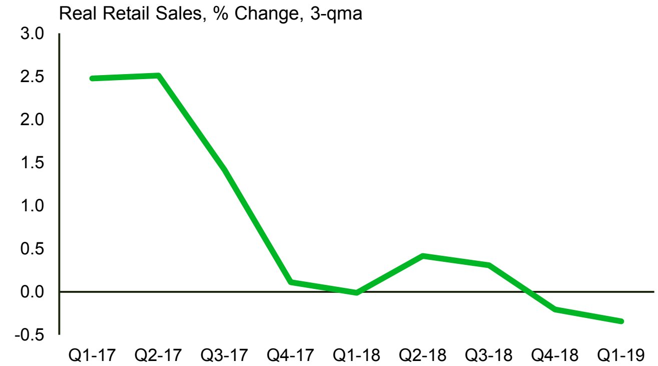
However, we don't anticipate the same contribution from these construction projects moving forward. Work on the Keeyask project should wind down through 2020, while activity on the Canadian portion of the Line 3 pipeline project was nearing completion this spring. These are major factors underpinning our view that growth will ease again in 2019. However, Manitoba's economy is set to recover somewhat in 2020, partly on the back of a more benign interest rate environment than expected a few months ago and an upturn in the economic fortunes of other provinces.

Despite a pull-back in borrowing rates in recent months, consumer spending is likely in for another subdued year in 2019 amid slowing population growth and modest growth in real wages. What's more, while the province has added jobs so far in 2019, all of the gains have been in part-time work. However, the PST will be cut by 1 ppt on July 1st, providing some offset to these factors.

Slowing population growth combined with past rate hikes should keep a lid on home sales in coming months. However, demand will likely see some support in late 2019 from the First Time Homebuyers Incentive. This program will likely be well received amid still-challenging affordability conditions. On the supply side, falling building intentions point to softer homebuilding going forward.

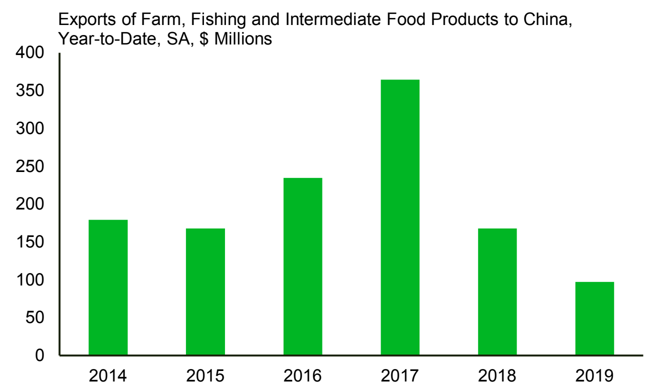
After a strong performance in 2018, exports dropped in the first quarter, weighed down by lower agricultural shipments. Looking ahead, we expect international exports to grow at a slower pace for the remainder of 2019 and 2020, alongside an easing expansion stateside. Growing tensions between Canada and China has left Manitoba in the crosshairs, with falling prices for canola crops depressing farm receipts and nominal GDP growth.

**Chart 1: Weak Retail Spending in Manitoba**




Source: Statistics Canada, TD Economics

**Chart 2: Shipments of Agricultural Products to China Slowing in the Wake of Import Bans**




Source: Statistics Canada, TD Economics

**Manitoba Economic Forecasts**

[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 1.4 | 1.3 | 1.7 |
| Nominal GDP | 3.2 | 3.0 | 4.1 |
| Employment | 0.6 | 1.4 | 0.7 |
| Unemployment Rate (%) | 6.0 | 5.4 | 5.4 |
| Housing Starts (000's) | 7.4 | 6.6 | 5.5 |
| Existing Home Prices | 1.2 | 1.2 | 3.9 |
| Home Sales | -5.9 | 2.7 | 3.0 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

# Ontario

Weakness in late 2018 looks to have lingered into the first quarter, as Ontario's economy likely recorded next to no growth. This weak start to the year leaves growth on track to slow significantly in 2019 following last year's respectable 2.2% outturn. That said, the first quarter details were probably better than the headline, as consumer spending strengthened and machinery and equipment investment increased sharply. This fits with our view that the first quarter was the nadir for growth, with some modest acceleration likely in the cards over the rest of 2019.

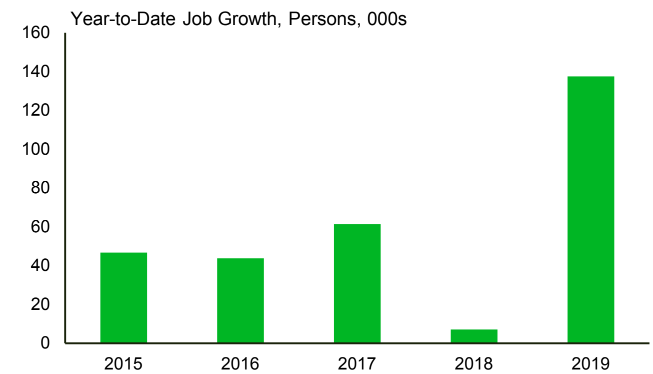
In order to address its sizeable deficit, the provincial government has outlined a plan to reduce spending growth well below its recent trend in coming years. This looming fiscal restraint is expected to exert a drag on growth, particularly in 2020. However, to the extent that Ontario's deficit and debt positons can be put on a more sustainable path, the provincial economy will benefit over the longer haul.

The recent escalation in trade policy uncertainty between the US and China represents a growing risk to Ontario's economy through potential negative impacts on US growth and overall confidence. It's not all bad news for businesses however, as U.S. tariffs on steel and aluminum products were recently dropped. Meanwhile, the deal struck between the U.S. and Mexico which avoids American tariffs on Mexican products should support near-term sentiment as it implies fewer potential roadblocks towards a ratification of the CUSMA trade agreement.

Also on the brighter side, Ontario's labour market is on fire, with 137.5k jobs added this year - eclipsing 2018's full-year tally. Strong job growth has kept consumer spending running at a modest clip in recent quarters, helping ease the sting of past rate hikes. Peering ahead, while the outsized employment gains are likely to moderate in the coming quarters, conditions in job markets are expected to remain strong and supportive to further spending gains.

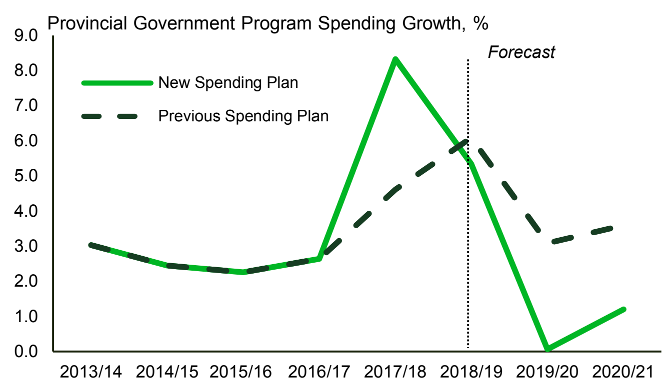
After an adjustment in housing activity that has extended for nearly 2 years, 'green shoots' have recently been observed in Ontario's housing market, underpinned by rapid population growth, falling mortgage rates, and healthy labour markets. Provincial sales have climbed in 3 of the past 4 months, with further gains likely moving forward as demand benefits from healthy fundamentals.

**Chart 1: Ontario's Job Market is on Fire**




Source: Statistics Canada, TD Economics

**Chart 2: Provincial Fiscal Restraint to Weigh on Growth**




Source: Provincial Governments, TD Economics

| Ontario Economic Forecasts [ Annual average % change, unless otherwise noted ] | | | |
|---|---|---|---|
| | 2018 | 2019 | 2020 |
| Real GDP | 2.2 | 1.3 | 1.4 |
| Nominal GDP | 3.4 | 3.6 | 3.6 |
| Employment | 1.6 | 2.6 | 0.8 |
| Unemployment Rate (%) | 5.6 | 5.7 | 5.7 |
| Housing Starts (000's) | 79.4 | 69.4 | 73.9 |
| Existing Home Prices | -1.7 | 4.7 | 4.6 |
| Home Sales | -13.3 | 7.5 | 8.0 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

# Québec

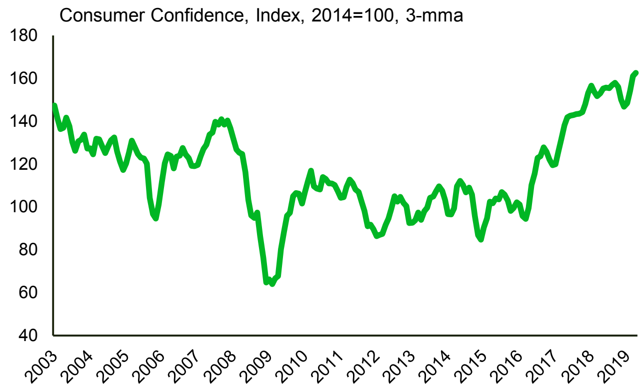
Quebec has not been immune to the softness that has gripped provincial economies since late last year. Growth in Quebec (+1.5%) managed to outperform the national average in the fourth quarter of 2018, but the details were decidedly softer. What's more, the pace of expansion likely slowed further in the opening quarter of 2019, as net trade took a big bite out of growth. This sub-par start to 2019 underpins our view that economic growth will ease to 1.7% this year – still a fairly strong, above-trend showing and notably faster than what is expected for the country overall.

Consumer spending was soft to end last year. Past increases in interest rates were partly to blame, with rate-sensitive motor vehicle sales dragging down the headline. However, household finances are in relatively good shape, consumer confidence is elevated, and labour markets are booming. Indeed, from January to May, nearly 45k (mostly full-time) jobs were created in the province, carving the unemployment rate to an all-time low. These conditions, alongside a more recent pull-back in borrowing costs, fueled a probable pick up in first quarter spending growth. And, these same factors should continue buoying household consumption moving forward.

Against what was a highly uncertain backdrop at the time, business investment took a step back to close 2018. However, this weakness probably turned around in the first quarter. Looking ahead, non-residential spending should continue to rise, boosted by federal and provincial accelerated depreciation measures and a relatively healthy domestic backdrop. On the external front, the recently lifted U.S. tariffs on steel and aluminum products will likely enhance what is already elevated business confidence, particularly as aluminum products are an important export for Quebec. However, overall export growth should ease alongside a slowing U.S. economy. What's more, trade skirmishes between the U.S. and China will likely dent sentiment.

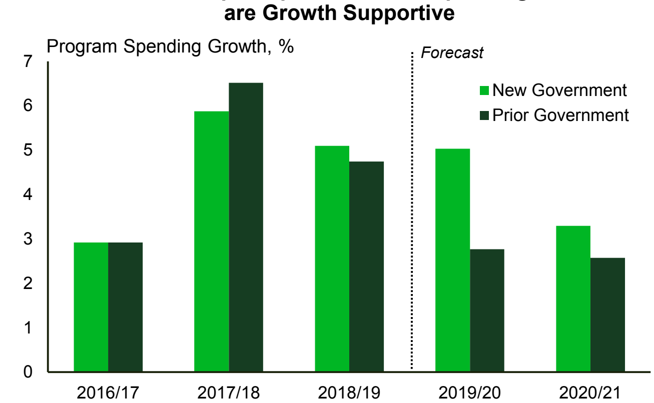
Measures contained in provincial government's 2019/20 budget are growth supportive, combining modest tax relief for households with ramped up program and infrastructure spending. Moreover, policies to enhance the integration of immigrants and temporary foreign workers were introduced in tandem with incentives for older workers to stay in the labour force. These measures will be positive for growth in 2019 and 2020.

**Chart 1: Healthy Labour Markets Buoying Consumer Spirits in Quebec**




Source: Conference Board of Canada, TD Economics

**Chart 2: Ramped Up Government Spending Plans are Growth Supportive**




Source: Provincial Governments, TD Economics

**Québec Economic Forecasts**

[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 2.1 | 1.7 | 1.7 |
| Nominal GDP | 4.2 | 4.0 | 3.9 |
| Employment | 0.9 | 1.5 | 0.6 |
| Unemployment Rate (%) | 5.4 | 5.2 | 5.5 |
| Housing Starts (000's) | 46.9 | 46.9 | 43.8 |
| Existing Home Prices | 5.3 | 4.8 | 3.5 |
| Home Sales | 4.8 | 7.6 | 5.7 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

## New Brunswick

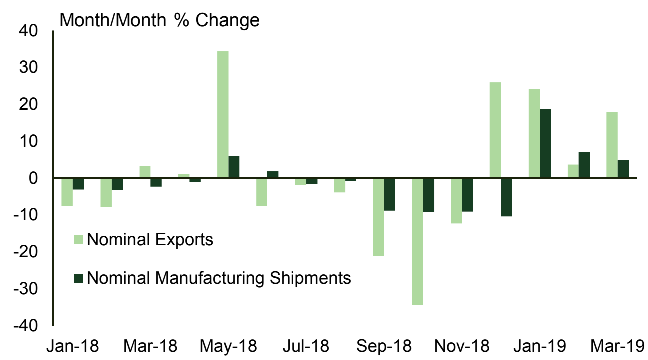
After an impressive run of above-trend growth in 2016 and 2017, New Brunswick's economy came to a virtual standstill last year. Transitory factors in the province's manufacturing sector weighed heavily on the province's expansion to end last year. This weak handoff, a drop in homebuilding so far this year, and a more subdued outlook for exports have put New Brunswick on track to advance by only 0.5% in 2019, tied for last place on the provincial leaderboard. We expect real GDP gains to return closer to trend-like conditions in 2020, but demographic challenges will continue to cap any further upside.

New Brunswick's manufacturing sales and exports took a hit in late 2018 on the back of maintenance and an explosion at its large oil refinery (Chart 1). The sector managed to stage a recovery from these setbacks in the first quarter of the year, but only partially. While further recovery is likely over the second half of the year, the improvement will be muted by weakness in the global market for key forestry and wood products industry, where activity is being held back by low lumber prices, soft demand, and lingering tariffs. The recently implemented CETA and CPTPP trade agreements provide a significant medium-term growth opportunity, particularly within the agriculture and forestry businesses. Also providing some offset to temporary weaknesses in the province's goods sectors is a rising services sector, with several large corporations choosing to establish service centers and offices in the province's cities.

Meanwhile, a one recent bright spot is New Brunswick's labour market, which has been showing signs of firming following last year's lackluster performance. Job growth is up 0.7% (ytd y/y), supported by solid growth in the province's labour force. New Brunswick continues to benefit from a rising population base on the back of record-high international immigration into the province. Still, negative interprovincial migration and a low natural rate continue to act as headwinds to the province's longer-term growth potential.

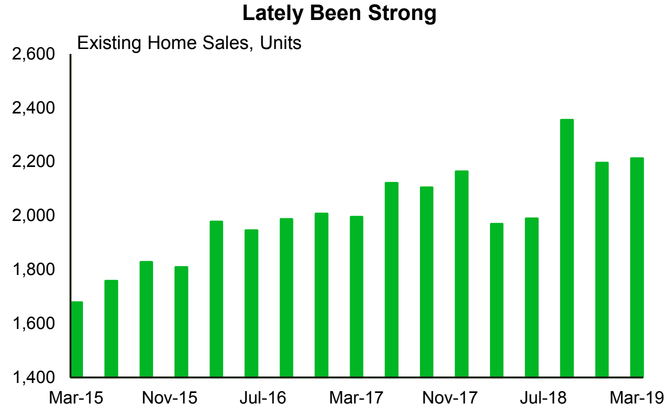
While homebuilding in the province has been weak, the resale market has been strong since the second half of last year. (Chart 2) Indeed, existing home sales are up a noteworthy 15% relative to 2017. In addition to robust immigration, much of this is due to more favourable borrowing rates and supportive affordability conditions.

**Chart 1: Partial Recovery Ongoing in New Brunswick's Manufacturing Shipments and Exports**




Source: Statistics Canada, TD Economics

**Chart 2: New Brunswick's Resale Market Has Lately Been Strong**




Source: CREA, TD Economics

| New Brunswick Economic Forecasts<br>[ Annual average % change, unless otherwise noted ] | | | |
|---|---|---|---|
| | 2018 | 2019 | 2020 |
| Real GDP | 0.1 | 0.5 | 0.9 |
| Nominal GDP | 1.0 | 2.1 | 2.9 |
| Employment | 0.3 | 0.8 | -0.1 |
| Unemployment Rate (%) | 8.0 | 7.9 | 8.1 |
| Housing Starts (000's) | 2.3 | 1.8 | 1.9 |
| Existing Home Prices | 5.9 | 3.9 | 5.6 |
| Home Sales | 1.5 | 6.8 | 4.7 |
| Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics | | | |

# Nova Scotia

On an industry basis, Nova Scotia's economy expanded at a 1.2% rate in 2018, in line with our expectations. This was a respectable outturn for the province, with growth clocking in above the post-recession average. The mining sector supported growth last year, as production at the new Tuoquoy gold mine ramped up. At the same time, oil and gas production moderated and retail spending was soft.

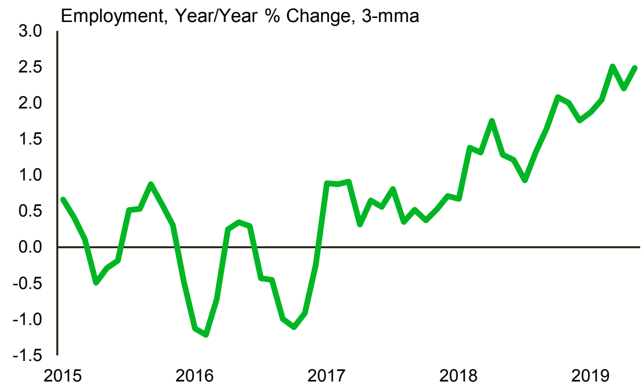
The economy gained some steam in the early part of 2019. Indeed, nearly 10k jobs were created through May, marking the best such performance since 1994. This showed up in consumer spending, with inflation-adjusted retail sales bouncing back in the first quarter. In fact, sales volumes chalked up their best quarter for growth since 2015 in Q1.

Abetting this positive momentum is the 2019/20 provincial budget, which beefed up program and capital spending for this fiscal year. The government also introduced a new accelerated capital cost allowance, which should lift business investment going forward. Further support to investment should come from the decommissioning of the Sable and Deep Panuke natural gas fields. Meanwhile, medium-term spending will be jolted by the construction of two new coast guard patrol ships in Halifax.

Population growth matched a multi-decade high in the first quarter and, more broadly, has been trending higher since 2016. These gains have been fueled mostly be international migration, which likely has some staying power owing to rising federal immigration targets. Robust population growth has sparked gains in home sales and homebuilding, with the former rising so far this year and the latter remaining elevated. Nova Scotia's tight housing market is poised to benefit from the federal government's First-time Home Buyers Incentive, particularly as prevailing home price and income levels fall well within program thresholds.

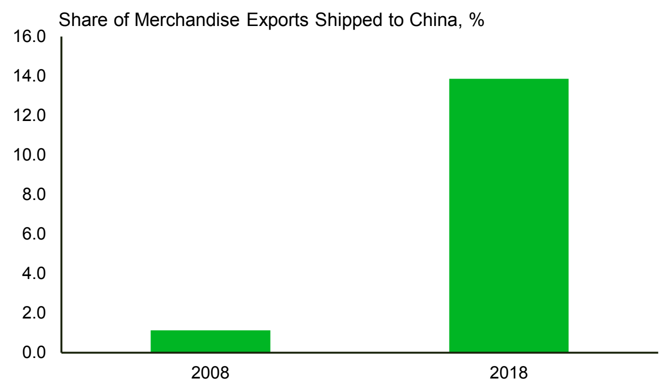
Yet, despite all these positives, we remain hesitant to mark up our growth forecast for this year significantly. This is because heightened trade uncertainty should dampen the expansions in the U.S. and China, thus weighing on exports. Moderating growth in China is particularly impactful, as the share of Nova Scotia's exports shipped to China has risen sharply since 2014. However, should the large-scale Goldboro LNG project get a green light (a final investment decision is due sometime this year), our forecasts will receive a significant upgrade.

**Chart 1: Employment Expanding Rapidly in Nova Scotia**




Source: Statistics Canada, TD Economics

**Chart 2: Nova Scotia Levered to Slowing Chinese Economy**




Source: Statistics Canada, TD Economics

**Nova Scotia Economic Forecasts**
[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 1.2 | 1.1 | 1.2 |
| Nominal GDP | 2.6 | 3.0 | 3.1 |
| Employment | 1.5 | 2.2 | -0.1 |
| Unemployment Rate (%) | 7.6 | 6.9 | 7.4 |
| Housing Starts (000's) | 4.9 | 4.0 | 4.0 |
| Existing Home Prices | 3.2 | 6.7 | 3.9 |
| Home Sales | 5.3 | 6.1 | 5.5 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

## Prince Edward Island

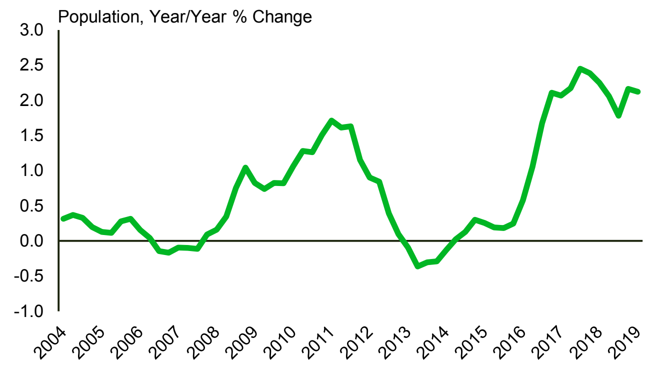
PEI's economy has benefitted tremendously from multi-decade highs in population growth. International migration has fueled this strength, with ramped up federal immigration targets helping newcomers flock to PEI. Historically, the province has had some trouble retaining these immigrants. However, there is some evidence that this may be turning around, with the rate of newcomers leaving for other provinces slowing since 2016.

Robust population growth – and the attendant boost to domestic activity – coupled with sturdy economic conditions stateside propelled a sizzling 2.6% outturn for industry-based GDP in 2018 (we expect that expenditure-based GDP nearly matched this pace last year). This strength found its way to labour markets, with employment up 3.0% and the unemployment rate falling to a record low. These firm trends have been sustained so far in 2019, with payroll employment up solidly in the first quarter. Meanwhile, other sectors are also performing well, with manufacturing shipments higher year-over-year, inflation-adjusted retail spending advancing at a strong clip, government programs supporting a rise in homebuilding, and wholesale trade surging. What's more, tourism activity remained healthy in the first quarter, with overnight stays advancing at a double-digit annual pace. This positive momentum has led us to upgrade our PEI forecast for 2019.

However, we still expect a slower pace of growth in both 2019 and 2020 relative to the outsized performances of recent years. Firstly, with labour markets becoming tighter, it will be hard for job growth to match 2018's torrid performance. Softer employment growth should keep a lid on consumer spending. Meanwhile, past rate hikes combined with strong home price growth in recent years has chipped away at affordability, which is expected to put a damper on near-term home sales activity. On the export side, both the US and global economies have been slowing, which has negative implications for manufacturing and tourism. Finally, the province's latest Capital Budget points to some moderation in infrastructure spending beyond this fiscal year.

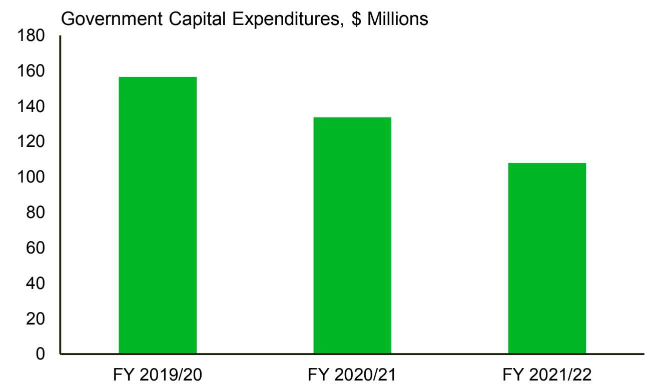
The newly elected PC government's platform contains a modest mix of tax cuts and spending initiatives. Bigger-ticket promises include pledges to cut small business and personal income taxes. The Province is sporting its 3rd largest surplus in nearly 40 years, setting the table nicely for the new government to allocate funding to its key priorities.

**Chart 1: Robust Population Growth Boosting Activity in PEI**




Source: Statistics Canada, TD Economics

**Chart 2: PEI Government's Capital Spending Poised to Slow After this Fiscal Year**




Source: PEI Government, TD Economics

**P.E.I. Economic Forecasts**

[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | 2.5 | 2.0 | 1.3 |
| Nominal GDP | 4.3 | 3.9 | 3.3 |
| Employment | 3.0 | 0.6 | 0.1 |
| Unemployment Rate (%) | 9.4 | 9.6 | 9.8 |
| Housing Starts (000's) | 1.0 | 0.7 | 1.1 |
| Existing Home Prices | 4.5 | 9.4 | 4.6 |
| Home Sales | -4.5 | -8.7 | 5.2 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

## Newfoundland & Labrador

A ramp-up in oil production, a resumption in iron ore production, and the start of construction on a number of smaller-scale capital projects should support a modest bounce-back in Newfoundland & Labrador's economy this year. In 2020, growth is expected to slip back to a more modest rate as the impact of this year's construction strength fades and demographics continue to weigh on labour force growth.

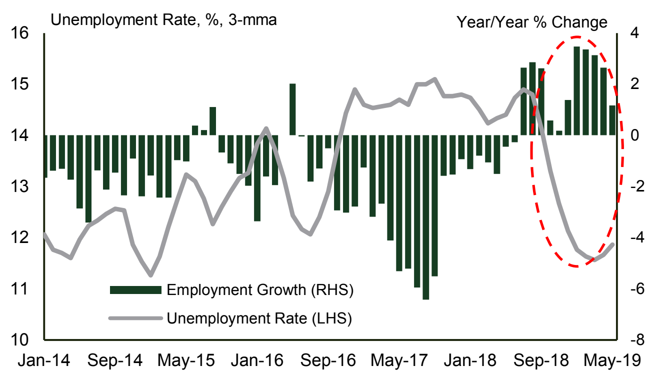
An outlook for increased commodity production this year is instrumental in driving near-term gains in exports and manufacturing activity. For instance, oil production is up 3.5% year-to-date y/y, and is expected to rise further with a ramp up at the Hibernia and Hebron oil fields. The resumption of iron ore production after a two month strike at the Iron Ore Company of Canada in 2018 should also lend a helping hand to export volumes amid a tight global market.

After a subdued 2018, the non-residential construction sector is expected to be a major contributor to growth. Capital spending is projected to receive a boost from the West White Rose field expansion and Voisey's Bay underground mine expansion. Other support could come from pre-development spending on the Bay Du Nord project, if sanctioned, in addition to increased offshore exploration activity.

In contrast, consumer spending is likely to remain tepid. Retail sales are up a modest 2% (ytd y/y) so far in 2019, implying flat volumes growth. This caution is despite signs of an improving labour market, where job and wage growth have recently surprised on the upside (Chart 1). In contrast, housing demand may be starting to respond to the stronger job conditions as well as a recent pull-back in borrowing rates. Resale activity in the province was up more than 7% in Q1 relative to the last quarter of 2018 (Chart 2). The impact of the new federal housing measures, notably the First Time Home Buyer's initiative, is also likely to contribute to a modest uptick in sales this year. While these signals are positive, ongoing demographic pressures will continue to limit the upside potential in the province's housing markets over the medium term.

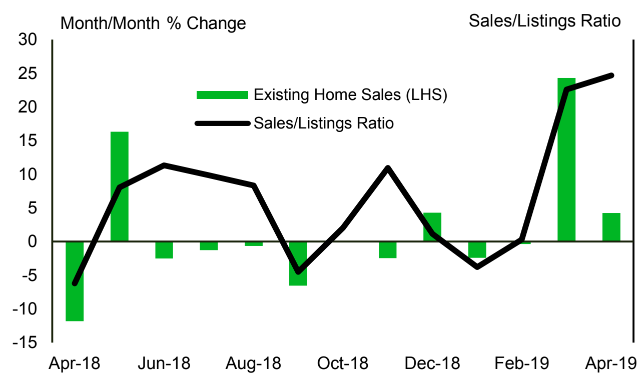
This year, the provincial budget is expected to move back to a balanced position, owing largely to a federal $2.5 billion payment related to the Atlantic Accord. Given that this payment is only one-time (front-loaded), it does little to address a $700 million structural deficit, a gap that the government plans to eliminate by FY2022-23.

**Chart 1: Newfoundland & Labrador's Labour Markets Have Recently Surprised on the Upside**




Source: Statistics Canada, TD Economics

**Chart 2: Newfoundland & Labrador's Resale Market was Decent in Q1 (but Downside Risk Remains)**




Source: CREA, TD Economics

**NFLD & Labrador Economic Forecasts**

[ Annual average % change, unless otherwise noted ]

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Real GDP | -2.7 | 1.5 | 1.1 |
| Nominal GDP | 0.1 | 4.0 | 3.6 |
| Employment | 0.4 | 1.5 | -0.7 |
| Unemployment Rate (%) | 13.8 | 12.1 | 12.5 |
| Housing Starts (000's) | 1.5 | 0.7 | 1.0 |
| Existing Home Prices | -1.4 | -2.8 | -1.1 |
| Home Sales | -5.1 | 8.7 | 3.7 |

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics

# Provincial Economic Forecasts

| Provincial Economic Forecasts | Real GDP (% Chg.) | | | Nominal GDP (% Chg.) | | | Employment (% Chg.) | | | Unemployment Rate (average, %) | | | Housing Starts (Thousands) | | | Home Prices (% Chg.) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** |
| **National** | **1.9** | **1.3** | **1.7** | **3.6** | **3.3** | **4.0** | **1.3** | **2.0** | **0.7** | **5.8** | **5.7** | **5.9** | **214** | **198** | **196** | **-3.5** | **-2.0** | **3.2** |
| Newfoundland & Labrador | -2.7 | 1.5 | 1.1 | 0.1 | 4.0 | 3.6 | 0.4 | 1.5 | -0.7 | 13.8 | 12.1 | 12.5 | 1.5 | 0.7 | 1.0 | -1.4 | -2.8 | -1.1 |
| Prince Edward Island | 2.5 | 2.0 | 1.3 | 4.3 | 3.9 | 3.3 | 3.0 | 0.6 | 0.1 | 9.4 | 9.6 | 9.8 | 1.0 | 0.7 | 1.1 | 4.5 | 9.4 | 4.6 |
| Nova Scotia | 1.2 | 1.1 | 1.2 | 2.6 | 3.0 | 3.1 | 1.5 | 2.2 | -0.1 | 7.6 | 6.9 | 7.4 | 4.9 | 4.0 | 4.0 | 3.2 | 6.7 | 3.9 |
| New Brunswick | 0.1 | 0.5 | 0.9 | 1.0 | 2.1 | 2.9 | 0.3 | 0.8 | -0.1 | 8.0 | 7.9 | 8.1 | 2.3 | 1.8 | 1.9 | 5.9 | 3.9 | 5.6 |
| Québec | 2.1 | 1.7 | 1.7 | 4.2 | 4.0 | 3.9 | 0.9 | 1.5 | 0.6 | 5.4 | 5.2 | 5.5 | 46.9 | 46.9 | 43.8 | 5.3 | 4.8 | 3.5 |
| Ontario | 2.2 | 1.3 | 1.4 | 3.4 | 3.6 | 3.6 | 1.6 | 2.6 | 0.8 | 5.6 | 5.7 | 5.7 | 79.4 | 69.4 | 73.9 | -1.7 | 4.7 | 4.6 |
| Manitoba | 1.4 | 1.3 | 1.7 | 3.2 | 3.0 | 4.1 | 0.6 | 1.4 | 0.7 | 6.0 | 5.4 | 5.4 | 7.4 | 6.6 | 5.5 | 1.2 | 1.2 | 3.9 |
| Saskatchewan | 1.5 | 0.8 | 1.2 | 3.2 | 2.1 | 3.8 | 0.5 | 1.4 | 0.7 | 6.1 | 5.5 | 5.8 | 3.6 | 2.3 | 4.1 | -2.3 | -2.0 | -0.2 |
| Alberta | 2.0 | 0.5 | 2.1 | 3.5 | 1.9 | 4.8 | 1.9 | 0.6 | 1.2 | 6.6 | 6.8 | 6.7 | 26.3 | 23.4 | 25.7 | -2.4 | -3.3 | 0.0 |
| British Columbia | 2.4 | 1.5 | 2.0 | 4.7 | 3.5 | 4.4 | 1.1 | 3.1 | 0.8 | 4.7 | 4.6 | 4.7 | 40.9 | 42.1 | 34.9 | 0.9 | -7.9 | -0.6 |

Source: CREA, CMHC, Statistics Canada, TD Economics. Forecasts by TD Economics as at June 2019.

## Disclaimer

# Scotiabank Forecast

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GLOBAL ECONOMICS

# SCOTIABANK'S FORECAST TABLES

July 12, 2019

| International | 2000–17 | 2017 | 2018 | 2019f | 2020f | 2000–17 | 2017 | 2018 | 2019f | 2020f |
|---|---|---|---|---|---|---|---|---|---|---|
| | Real GDP (annual % change) | | | | | Consumer Prices (y/y % change, year-end) | | | | |
| World (based on purchasing power parity) | 3.9 | 3.8 | 3.7 | 3.1 | 3.2 | | | | | |
| Canada | 2.1 | 3.0 | 1.9 | 1.4 | 2.0 | 1.9 | 1.8 | 2.0 | 1.9 | 1.9 |
| United States | 2.0 | 2.2 | 2.9 | 2.5 | 1.6 | 2.2 | 2.1 | 2.2 | 1.7 | 2.1 |
| Mexico | 2.2 | 2.1 | 2.0 | 0.9 | 1.1 | 4.4 | 6.8 | 4.8 | 4.1 | 4.1 |
| United Kingdom | 1.9 | 1.8 | 1.4 | 1.1 | 1.2 | 2.1 | 3.0 | 2.1 | 1.8 | 2.0 |
| Eurozone | 1.4 | 2.4 | 1.9 | 1.1 | 1.3 | 1.8 | 1.3 | 1.5 | 1.3 | 1.4 |
| Germany | 1.4 | 2.2 | 1.4 | 0.7 | 1.2 | 1.5 | 1.4 | 1.6 | 1.5 | 1.6 |
| France | 1.4 | 2.3 | 1.7 | 1.3 | 1.3 | 1.4 | 1.2 | 1.6 | 1.3 | 1.4 |
| China | 9.3 | 6.8 | 6.6 | 6.2 | 6.0 | 2.3 | 1.8 | 1.8 | 2.6 | 2.3 |
| India | 7.1 | 6.9 | 7.4 | 6.5 | 7.0 | 6.8 | 5.2 | 2.1 | 4.1 | 4.8 |
| Japan | 0.9 | 1.9 | 0.8 | 0.8 | 0.6 | 0.1 | 1.1 | 0.3 | 1.8 | 0.8 |
| South Korea | 4.9 | 3.2 | 2.7 | 2.0 | 2.7 | 2.5 | 1.4 | 1.3 | 1.2 | 1.6 |
| Australia | 2.9 | 2.4 | 2.8 | 2.3 | 2.6 | 2.7 | 1.9 | 1.8 | 1.6 | 1.9 |
| Thailand | 4.1 | 4.0 | 4.1 | 3.2 | 3.4 | 1.9 | 0.8 | 0.4 | 1.2 | 1.6 |
| Brazil | 2.5 | 1.1 | 1.1 | 0.9 | 1.8 | 6.5 | 3.0 | 3.8 | 4.3 | 4.6 |
| Colombia | 3.9 | 1.4 | 2.6 | 3.2 | 3.6 | 5.1 | 4.1 | 3.2 | 3.2 | 3.1 |
| Peru | 5.0 | 2.5 | 3.9 | 3.1 | 3.7 | 2.7 | 1.4 | 2.2 | 2.2 | 2.3 |
| Chile | 3.9 | 1.5 | 4.0 | 3.2 | 3.2 | 3.3 | 2.3 | 2.6 | 2.8 | 3.0 |

| Commodities | 2000–17 | 2017 | 2018 | 2019f | 2020f |
|---|---|---|---|---|---|
| | (annual average) | | | | |
| WTI Oil (USD/bbl) | 62 | 51 | 65 | 56 | 55 |
| Brent Oil (USD/bbl) | 65 | 55 | 72 | 65 | 62 |
| WCS - WTI Discount* (USD/bbl) | -16 | -13 | -26 | -14 | -21 |
| Nymex Natural Gas (USD/mmbtu) | 4.83 | 3.02 | 3.07 | 2.71 | 2.75 |
| Copper (USD/lb) | 2.38 | 2.80 | 2.96 | 2.80 | 3.00 |
| Zinc (USD/lb) | 0.84 | 1.31 | 1.33 | 1.22 | 1.20 |
| Nickel (USD/lb) | 7.12 | 4.72 | 5.95 | 5.70 | 6.00 |
| Aluminium (USD/lb) | 0.87 | 0.89 | 0.96 | 0.90 | 0.90 |
| Iron Ore (USD/tonne) | 67 | 72 | 70 | 90 | 72 |
| Metallurgical Coal (USD/tonne) | 131 | 187 | 206 | 195 | 170 |
| Gold, London PM Fix (USD/oz) | 890 | 1,257 | 1,268 | 1,350 | 1,350 |
| Silver, London PM Fix (USD/oz) | 14.80 | 17.05 | 15.71 | 15.37 | 15.00 |

* 2008-16 average.
Sources: Scotiabank Economics, Statistics Canada, BEA, BLS, IMF, Bloomberg.

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# SCOTIABANK'S FORECAST TABLES

July 12, 2019

| North America | 2000–17 | 2017 | 2018 | 2019f | 2020f | 2000–17 | 2017 | 2018 | 2019f | 2020f |
|---|---|---|---|---|---|---|---|---|---|---|
| | Canada (annual % change, unless noted) | | | | | United States (annual % change, unless noted) | | | | |
| Real GDP | 2.1 | 3.0 | 1.9 | 1.4 | 2.0 | 2.0 | 2.2 | 2.9 | 2.5 | 1.6 |
| Consumer spending | 2.9 | 3.5 | 2.1 | 2.0 | 1.9 | 2.4 | 2.5 | 2.6 | 2.2 | 1.9 |
| Residential investment | 3.6 | 2.4 | -1.5 | -3.6 | 1.3 | -0.3 | 3.3 | -0.3 | -1.9 | 0.8 |
| Business investment* | 2.2 | 2.2 | 2.2 | 0.2 | 5.5 | 3.0 | 5.3 | 6.9 | 4.0 | 2.3 |
| Government | 2.2 | 2.7 | 3.0 | 1.6 | 1.7 | 1.0 | -0.1 | 1.5 | 2.0 | 1.6 |
| Exports | 1.3 | 1.1 | 3.2 | 1.7 | 2.4 | 3.7 | 3.0 | 4.0 | 2.0 | 1.8 |
| Imports | 3.0 | 4.2 | 2.9 | 1.5 | 2.8 | 3.7 | 4.6 | 4.5 | 1.8 | 2.9 |
| Nominal GDP | 4.3 | 5.6 | 3.6 | 2.7 | 4.2 | 4.0 | 4.2 | 5.2 | 4.2 | 3.3 |
| GDP deflator | 2.1 | 2.6 | 1.7 | 1.3 | 2.1 | 1.9 | 1.9 | 2.3 | 1.6 | 1.6 |
| Consumer price index (CPI) | 1.9 | 1.6 | 2.3 | 1.8 | 2.0 | 2.2 | 2.1 | 2.4 | 1.7 | 2.0 |
| CPI ex. food & energy | 1.6 | 1.6 | 1.9 | 1.9 | 2.0 | 2.0 | 1.8 | 2.1 | 2.0 | 2.2 |
| Pre-tax corporate profits | 0.0 | 20.1 | 0.5 | -4.1 | 2.1 | 5.3 | 3.2 | 7.8 | 0.2 | 1.9 |
| Employment | 1.4 | 1.9 | 1.3 | 2.1 | 1.0 | 0.7 | 1.6 | 1.7 | 1.5 | 1.0 |
| Unemployment rate (%) | 7.1 | 6.3 | 5.8 | 5.7 | 5.9 | 6.1 | 4.4 | 3.9 | 3.8 | 3.9 |
| Current account balance (CAD, USD bn) | -18.7 | -59.4 | -58.5 | -57.6 | -55.9 | -500 | -440 | -491 | -543 | -606 |
| Merchandise trade balance (CAD, USD bn) | 22.9 | -23.9 | -22.0 | -26.1 | -28.0 | -680 | -805 | -887 | -894 | -971 |
| Federal budget balance (FY, CAD, USD bn) | -3.6 | -17.8 | -19.0 | -11.8 | -19.8 | -540 | -665 | -779 | -896 | -892 |
| percent of GDP | -0.2 | -0.9 | -0.9 | -0.5 | -0.8 | -3.7 | -3.4 | -3.8 | -4.2 | -4.0 |
| Housing starts (000s, mn) | 200 | 220 | 213 | 202 | 199 | 1.26 | 1.20 | 1.25 | 1.24 | 1.26 |
| Motor vehicle sales (000s, mn) | 1,678 | 2,036 | 1,983 | 1,935 | 1,915 | 15.6 | 17.1 | 17.2 | 16.8 | 16.7 |
| Industrial production | 0.0 | 4.9 | 2.9 | 0.4 | 1.9 | 0.7 | 2.3 | 4.0 | 1.9 | 1.7 |
| | Mexico (annual % change) | | | | | | | | | |
| Real GDP | 2.2 | 2.1 | 2.0 | 0.9 | 1.1 | | | | | |
| Consumer price index (year-end) | 4.4 | 6.8 | 4.8 | 4.1 | 4.1 | | | | | |
| Current account balance (USD bn) | -15.0 | -19.6 | -21.6 | -22.1 | -20.8 | | | | | |
| Merchandise trade balance (USD bn) | -7.2 | -11.0 | -13.6 | -5.8 | -13.1 | | | | | |

Sources: Scotiabank Economics, Statistics Canada, CMHC, BEA, BLS, Bloomberg. *For Canada it includes capital expenditures by businesses and non-profit institutions.

| Quarterly Forecasts | 2018 | 2019 | | | | 2020 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Canada | Q4 | Q1 | Q2e | Q3f | Q4f | Q1f | Q2f | Q3f | Q4f |
| Real GDP (q/q ann. % change) | 0.3 | 0.4 | 2.5 | 1.5 | 2.3 | 2.4 | 2.0 | 1.5 | 1.7 |
| Real GDP (y/y % change) | 1.6 | 1.3 | 1.3 | 1.2 | 1.7 | 2.2 | 2.0 | 2.0 | 1.9 |
| Consumer prices (y/y % change) | 2.0 | 1.6 | 2.1 | 1.8 | 1.9 | 2.1 | 2.1 | 2.0 | 1.9 |
| Avg. of new core CPIs (y/y % change) | 1.9 | 1.9 | 2.1 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| **United States** | | | | | | | | | |
| Real GDP (q/q ann. % change) | 2.2 | 3.1 | 1.8 | 1.9 | 1.4 | 1.5 | 1.5 | 1.9 | 2.1 |
| Real GDP (y/y % change) | 3.0 | 3.2 | 2.6 | 2.2 | 2.1 | 1.6 | 1.6 | 1.6 | 1.7 |
| Consumer prices (y/y % change) | 2.2 | 1.6 | 1.6 | 1.6 | 1.7 | 2.0 | 2.0 | 2.0 | 2.1 |
| CPI ex. food & energy (y/y % change) | 2.2 | 2.1 | 2.0 | 2.0 | 2.0 | 2.1 | 2.2 | 2.2 | 2.2 |
| Core PCE deflator (y/y % change) | 1.9 | 1.7 | 1.6 | 1.6 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 |

Sources: Scotiabank Economics, Statistics Canada, BEA, BLS, Bloomberg.

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| | 2018 | 2019 | | | | 2020 | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Central Bank Rates** | **Q4** | **Q1** | **Q2** | **Q3f** | **Q4f** | **Q1f** | **Q2f** | **Q3f** | **Q4f** |
| **Americas** | | | | (%, end of period) | | | | | |
| Bank of Canada | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 |
| US Federal Reserve (upper bound) | 2.50 | 2.50 | 2.50 | 2.00 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 |
| Bank of Mexico | 8.25 | 8.25 | 8.25 | 8.25 | 8.25 | 8.25 | 8.00 | 7.75 | 7.50 |
| Central Bank of Brazil | 6.50 | 6.50 | 6.50 | 6.50 | 7.00 | 7.75 | 8.25 | 8.50 | 8.50 |
| Bank of the Republic of Colombia | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.50 | 4.50 | 4.50 |
| Central Reserve Bank of Peru | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.50 | 2.50 | 2.50 | 2.50 |
| Central Bank of Chile | 2.75 | 3.00 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.75 | 3.25 |
| **Europe** | | | | | | | | | |
| European Central Bank MRO Rate | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| European Central Bank Deposit Rate | -0.40 | -0.40 | -0.40 | -0.50 | -0.50 | -0.50 | -0.50 | -0.50 | -0.50 |
| Bank of England | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 |
| **Asia/Oceania** | | | | | | | | | |
| Reserve Bank of Australia | 1.50 | 1.50 | 1.25 | 1.00 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 |
| Bank of Japan | -0.10 | -0.10 | -0.10 | -0.10 | -0.10 | -0.10 | -0.10 | -0.10 | -0.10 |
| People's Bank of China | 4.35 | 4.35 | 4.35 | 4.35 | 4.35 | 4.35 | 4.35 | 4.35 | 4.35 |
| Reserve Bank of India | 6.50 | 6.25 | 5.75 | 5.50 | 5.25 | 5.25 | 5.25 | 5.25 | 5.25 |
| Bank of Korea | 1.75 | 1.75 | 1.75 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| Bank of Thailand | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.50 | 1.50 | 1.50 | 1.50 |
| **Currencies and Interest Rates** | | | | | | | | | |
| **Americas** | | | | (end of period) | | | | | |
| Canadian dollar (USDCAD) | 1.36 | 1.33 | 1.31 | 1.31 | 1.28 | 1.28 | 1.28 | 1.25 | 1.25 |
| Canadian dollar (CADUSD) | 0.73 | 0.75 | 0.76 | 0.76 | 0.78 | 0.78 | 0.78 | 0.80 | 0.80 |
| Mexican peso (USDMXN) | 19.65 | 19.43 | 19.22 | 20.24 | 20.87 | 21.12 | 20.99 | 21.10 | 21.44 |
| Brazilian real (USDBRL) | 3.88 | 3.92 | 3.85 | 3.97 | 4.18 | 4.08 | 4.11 | 4.07 | 4.18 |
| Colombian peso (USDCOP) | 3,254 | 3,189 | 3,211 | 3,150 | 3,120 | 3,050 | 3,100 | 3,182 | 3,167 |
| Peruvian sol (USDPEN) | 3.37 | 3.32 | 3.29 | 3.34 | 3.35 | 3.36 | 3.32 | 3.33 | 3.30 |
| Chilean peso (USDCLP) | 694 | 680 | 679 | 660 | 645 | 645 | 645 | 640 | 640 |
| **Europe** | | | | | | | | | |
| Euro (EURUSD) | 1.15 | 1.12 | 1.14 | 1.13 | 1.15 | 1.19 | 1.22 | 1.24 | 1.24 |
| UK pound (GBPUSD) | 1.28 | 1.30 | 1.27 | 1.25 | 1.25 | 1.28 | 1.30 | 1.32 | 1.40 |
| **Asia/Oceania** | | | | | | | | | |
| Japanese yen (USDJPY) | 110 | 111 | 108 | 108 | 108 | 107 | 107 | 105 | 105 |
| Australian dollar (AUDUSD) | 0.70 | 0.71 | 0.70 | 0.75 | 0.75 | 0.77 | 0.77 | 0.78 | 0.78 |
| Chinese yuan (USDCNY) | 6.88 | 6.71 | 6.87 | 6.70 | 6.70 | 6.60 | 6.60 | 6.50 | 6.50 |
| Indian rupee (USDINR) | 69.8 | 69.1 | 69.0 | 68.0 | 68.0 | 67.0 | 67.0 | 66.0 | 66.0 |
| South Korean won (USDKRW) | 1,116 | 1,135 | 1,155 | 1,140 | 1,140 | 1,120 | 1,120 | 1,100 | 1,100 |
| Thai baht (USDTHB) | 32.5 | 31.7 | 30.7 | 31.0 | 31.0 | 30.5 | 30.5 | 30.0 | 30.0 |
| **Canada (Yields, %)** | | | | | | | | | |
| 3-month T-bill | 1.65 | 1.67 | 1.65 | 1.65 | 1.65 | 1.65 | 1.65 | 1.65 | 1.65 |
| 2-year Canada | 1.86 | 1.55 | 1.47 | 1.50 | 1.40 | 1.35 | 1.35 | 1.35 | 1.35 |
| 5-year Canada | 1.89 | 1.52 | 1.39 | 1.45 | 1.40 | 1.40 | 1.40 | 1.40 | 1.40 |
| 10-year Canada | 1.97 | 1.62 | 1.46 | 1.50 | 1.55 | 1.60 | 1.65 | 1.65 | 1.70 |
| 30-year Canada | 2.18 | 1.89 | 1.68 | 1.70 | 1.80 | 1.90 | 2.00 | 2.05 | 2.10 |
| **United States (Yields, %)** | | | | | | | | | |
| 3-month T-bill | 2.36 | 2.39 | 2.09 | 1.85 | 1.60 | 1.60 | 1.60 | 1.60 | 1.60 |
| 2-year Treasury | 2.49 | 2.26 | 1.76 | 1.70 | 1.70 | 1.80 | 1.80 | 1.80 | 1.80 |
| 5-year Treasury | 2.51 | 2.23 | 1.77 | 1.75 | 1.80 | 1.90 | 1.90 | 1.90 | 1.90 |
| 10-year Treasury | 2.68 | 2.41 | 2.00 | 2.10 | 2.20 | 2.35 | 2.40 | 2.45 | 2.45 |
| 30-year Treasury | 3.01 | 2.82 | 2.53 | 2.65 | 2.70 | 2.85 | 2.85 | 2.90 | 2.90 |

Sources: Scotiabank Economics, Bloomberg.

| The Provinces | (annual % change except where noted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Real GDP** | **CA** | **NL** | **PE** | **NS** | **NB** | **QC** | **ON** | **MB** | **SK** | **AB** | **BC** |
| 2000–17 | 2.1 | 2.4 | 1.8 | 1.3 | 1.2 | 1.8 | 2.0 | 2.3 | 2.0 | 2.8 | 2.7 |
| 2017 | 3.0 | 0.9 | 3.5 | 1.5 | 1.8 | 2.8 | 2.8 | 3.2 | 2.2 | 4.4 | 3.8 |
| 2018e | 1.9 | -2.7 | 2.6 | 1.2 | 0.1 | 2.5 | 2.2 | 1.3 | 1.6 | 2.3 | 2.4 |
| 2019f | 1.4 | 2.0 | 2.1 | 1.3 | 0.6 | 2.1 | 1.4 | 1.5 | 1.4 | 0.5 | 2.2 |
| 2020f | 2.0 | 0.8 | 2.0 | 1.3 | 0.8 | 1.8 | 1.8 | 1.5 | 1.6 | 2.5 | 3.0 |
| **Nominal GDP** | | | | | | | | | | | |
| 2000–17 | 4.3 | 5.6 | 4.2 | 3.3 | 3.4 | 3.7 | 3.9 | 4.4 | 5.4 | 5.9 | 4.7 |
| 2017 | 5.6 | 4.3 | 4.8 | 2.9 | 4.3 | 5.0 | 4.1 | 5.4 | 4.8 | 10.0 | 6.9 |
| 2018e | 3.6 | 0.5 | 4.6 | 3.2 | 1.9 | 4.2 | 3.4 | 3.1 | 3.8 | 4.5 | 4.4 |
| 2019f | 2.8 | 3.0 | 4.1 | 3.0 | 2.2 | 3.2 | 2.5 | 3.3 | 3.3 | 1.3 | 4.2 |
| 2020f | 4.1 | 3.8 | 3.9 | 3.3 | 2.5 | 3.7 | 3.7 | 3.3 | 4.0 | 4.6 | 5.7 |
| **Employment** | | | | | | | | | | | |
| 2000–17 | 1.4 | 0.6 | 1.1 | 0.6 | 0.4 | 1.3 | 1.3 | 1.0 | 1.1 | 2.2 | 1.5 |
| 2017 | 1.9 | -3.7 | 3.1 | 0.6 | 0.4 | 2.2 | 1.8 | 1.7 | -0.2 | 1.0 | 3.7 |
| 2018 | 1.3 | 0.5 | 3.0 | 1.5 | 0.3 | 0.9 | 1.6 | 0.6 | 0.4 | 1.9 | 1.1 |
| 2019f | 2.1 | 1.9 | 1.4 | 2.3 | 0.5 | 1.5 | 2.5 | 1.2 | 1.6 | 1.0 | 3.0 |
| 2020f | 1.0 | 0.2 | 0.8 | 0.3 | 0.2 | 0.8 | 1.2 | 0.6 | 0.7 | 1.0 | 1.5 |
| **Unemployment Rate (%)** | | | | | | | | | | | |
| 2000–17 | 7.1 | 14.3 | 11.1 | 8.8 | 9.5 | 7.9 | 7.0 | 5.1 | 5.0 | 5.3 | 6.5 |
| 2017 | 6.3 | 14.8 | 9.8 | 8.4 | 8.1 | 6.1 | 6.0 | 5.4 | 6.3 | 7.8 | 5.1 |
| 2018 | 5.8 | 13.8 | 9.4 | 7.6 | 8.0 | 5.5 | 5.6 | 6.0 | 6.1 | 6.6 | 4.7 |
| 2019f | 5.7 | 11.8 | 9.0 | 6.8 | 8.0 | 5.2 | 5.6 | 5.5 | 5.5 | 6.7 | 4.6 |
| 2020f | 5.9 | 11.6 | 9.0 | 6.8 | 8.0 | 5.4 | 5.8 | 5.5 | 5.5 | 6.8 | 4.7 |
| **Housing Starts (units, 000s)** | | | | | | | | | | | |
| 2000–17 | 200 | 2.5 | 0.8 | 4.3 | 3.4 | 44 | 72 | 5.2 | 5.2 | 34 | 29 |
| 2017 | 220 | 1.4 | 0.9 | 4.0 | 2.3 | 46 | 79 | 7.5 | 4.9 | 29 | 44 |
| 2018 | 213 | 1.1 | 1.1 | 4.8 | 2.3 | 47 | 79 | 7.4 | 3.6 | 26 | 41 |
| 2019f | 202 | 1.0 | 0.9 | 3.9 | 2.1 | 46 | 69 | 6.8 | 3.2 | 26 | 44 |
| 2020f | 199 | 1.3 | 0.8 | 3.8 | 2.0 | 41 | 72 | 6.0 | 4.8 | 30 | 37 |
| **Motor Vehicle Sales (units, 000s)** | | | | | | | | | | | |
| 2000–17 | 1,657 | 29 | 6 | 48 | 38 | 413 | 635 | 47 | 45 | 216 | 180 |
| 2017 | 2,041 | 33 | 9 | 59 | 42 | 453 | 847 | 62 | 56 | 245 | 235 |
| 2018 | 1,984 | 28 | 8 | 51 | 38 | 449 | 853 | 67 | 47 | 226 | 217 |
| 2019f | 1,935 | 30 | 9 | 51 | 39 | 447 | 813 | 60 | 49 | 220 | 217 |
| 2020f | 1,915 | 30 | 9 | 50 | 37 | 440 | 800 | 56 | 48 | 217 | 228 |
| **Budget Balances, Fiscal Year Ending March 31 (CAD mn)** | | | | | | | | | | | |
| 2017 | -18,957 | -1,148 | -1 | 151 | -117 | 2,361 | -2,435 | -789 | -1,218 | -10,784 | 2,727 |
| 2018 | -18,961 | -911 | 1 | 230 | 67 | 2,622 | -3,672 | -695 | -303 | -8,023 | 301 |
| 2019e | -11,815 | -522 | 14 | 28 | 5 | 2,500 | -11,700 | -470 | -380 | -6,711 | 374 |

Sources: Scotiabank Economics, Statistics Canada, CMHC, Budget documents; Quebec budget balance figures are after Generations Fund transfers.

# RBC Forecast

http://www.rbc.com/economics/economic-reports/pdf/provincial-forecasts/provfcst-jun2019.pdf

RBC ECONOMIC RESEARCH

## PROVINCIAL OUTLOOK

June 7, 2019

# Momentum shifting down in most provinces

- **Growth to moderate across most of the country:** Six out of 10 provinces to see a slowdown in 2019; outlook brightens in Newfoundland and Labrador after sharp contraction in 2018
- **Alberta's economy facing challenges:** Mandated oil production cuts by the government have been scaled back but effects of last fall's oil price tumble will continue to impact the economy negatively in 2019
- **Housing market cooling**: Housing markets have seen a correction, particularly in B.C. and Ontario, limiting their contribution to growth
- **Labour market tight in the majority of provinces:** Unemployment rate below 6% in five out of 10 provinces

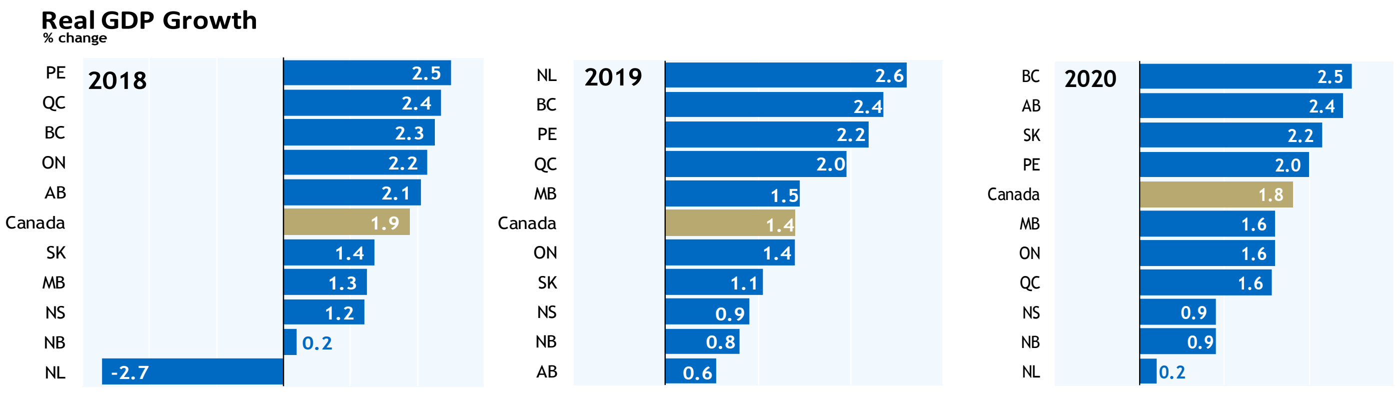
The overall climate facing provincial economics is far from stellar. The blows to the oil patch along with the unwinding from heavy reliance on the housing market in parts of the country temper growth expectations in 2019 across most provinces. The general moderation will continue this year, after growth in 2018 slowed to 1.9%. Although there was some good news with the removal of steel and aluminum tariffs, global trade disputes aren't helping the story.

The labour market remains a bright spot. Job creation has picked up and historically low unemployment rates have persisted in the majority of provinces so far this year. However, this will add more pressure on employers who have already been hiring from a smaller pool of laborers.

Housing, which provided a solid boost to growth over a number of years, has turned on its heels in B.C. and Ontario. The cooling of the housing market – more stark in B.C., but equally visible in Ontario, will act as a drag on GDP in 2019. While the housing related grind will ease as the year progresses in both provinces, we don't see scope for a material rebound in the next year either. Ontario will see softer growth this year, however B.C.'s will accelerate slightly thanks to the construction of the $40 billion LNG Canada megaproject in Kitimat. As for Quebec, improving fundamentals that include a growing working-age population, and a sturdy housing market will keep the province near the top of the provincial rankings.

Alberta's oil patch continues to face significant challenges with the effects spreading beyond the energy sector. We expect materially weaker growth this year. Amongst the other Prairie Provinces, Saskatchewan will see sluggish growth on the back of lower mining output and threats to its agricultural exports to China. Ratification of the CUSMA coupled with a strong labour market will boost Manitoba's prospects.

Out east, Newfoundland and Labrador will see a welcome return to positive growth with a big boost from oil production, and mining and offshore oil construction projects. PEI will extend its winning streak thanks to strong immigration and a robust labour market bolstering consumer spending. Nova Scotia will see a modest pullback in growth owing to lower business investment, while New Brunswick's economy will get into gear after a refinery explosion last year brought things to a virtual standstill.




Source: Statistics Canada, RBC Economic Research

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# BRITISH COLUMBIA – As housing slumps, business investment takes over

*While the housing market downturn grabs most headlines these days, a $4 billion surge in business capital spending is the bigger story this year. It will keep BC near the top of the provincial growth rankings.*

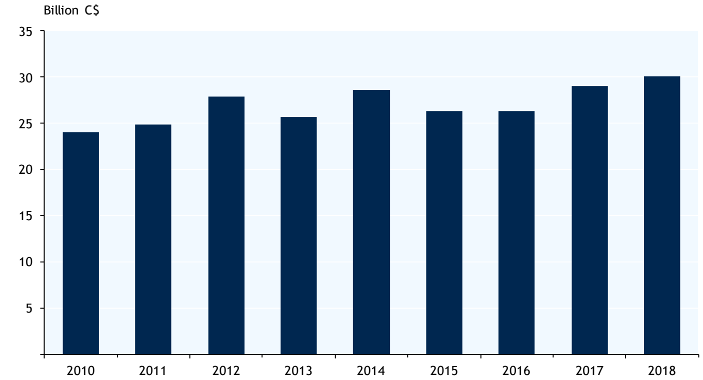
After leading all provinces in growth in 2016 and 2017, the BC economy slowed its pace last year—albeit to a still-respectable rate of 2.3% (third-fastest rate among the provinces). The significant cooling in the provincial housing market contributed strongly to this slowing, which had ripple effects across a number housing-sensitive industries in the services and manufacturing sectors. The labour market continued to be very robust, however. Job creation was healthy, if unspectacular, and the unemployment rate stood as the lowest among the provinces (4.7%).

Generally softer undertones have carried into 2019. Activity in the Vancouver housing market fell to a decade low this spring and prices continued to slide. There are now a lot more units for sale in the province which reduces demand for, and construction of new homes (especially of more expensive single-detached). Declining sales of building materials, furniture and motor vehicles are clear signs that the housing downturn is weighing on BC consumers who have become more circumspect. This is in stark contrast to their overflowing confidence not so long ago when rapidly-rising housing wealth fueled a four-year long shopping spree in the province.

Multiple layers of housing policy tightening will keep the market cool. Vancouver's benchmark price is down 8.9% since the June 2018 peak and we see it sliding further in the near term. This won't fuss policymakers who we suspect are quite pleased with the current state of affairs. Their intent ultimately is to tackle Vancouver's (and arguably Victoria's) severe affordability issues, so we expect them to keep suppressing homebuyer demand to sustain downward pressure on property values.

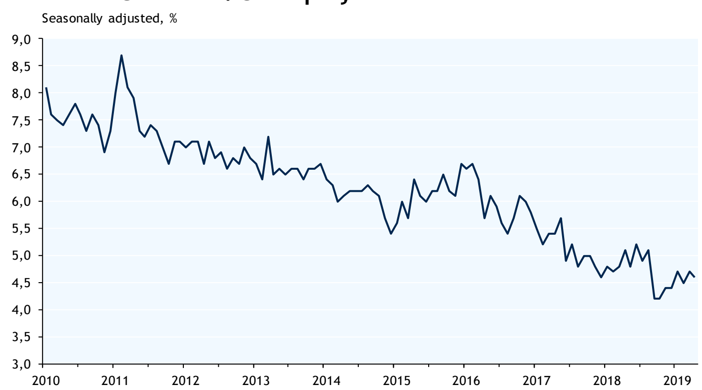
Yet a soft housing market and more cautious consumers aren't about to trip up BC's economy. A surge in spending on major capital projects will pick up any slack. Businesses plan to boost their capital expenditures by nearly $4 billion (up 13%) this year—the biggest increase ever in dollar terms. The ramping up of construction of the $40-billion LNG Canada megaproject in Kitimat, in particular, will generate a groundswell of activity in the province. Commercial real estate also is on an upswing—driving non-residential investment 21% above year-ago levels in the first quarter of 2019. Vigour in the non-residential construction will keep overall economic growth near the 2.5% mark in 2019 and 2020—strong enough to uphold BC's top-tier provincial growth ranking.

**British Columbia: Capital investment intentions**




Source: Statistics Canada, RBC Economic Research

**British Columbia: Unemployment rate**




Source: Statistics Canada, RBC Economic Research

## British Columbia forecast at a glance

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 3.2 | 3.8 | 2.3 | 2.4 | 2.5 |
| Nominal GDP | 6.0 | 6.9 | 4.6 | 4.5 | 4.7 |
| Employment | 3.2 | 3.7 | 1.1 | 2.5 | 0.7 |
| Unemployment Rate (%) | 6.0 | 5.1 | 4.7 | 4.9 | 5.0 |
| Retail Sales | 7.7 | 9.3 | 2.0 | 3.0 | 3.5 |
| Housing Starts (Thousands of Units) | 41.8 | 43.7 | 40.9 | 39.8 | 35.0 |
| Consumer Price Index | 1.9 | 2.1 | 2.7 | 2.2 | 1.8 |

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# ALBERTA - Rough start to 2019 but positive growth still expected

*Last fall's oil price tumble still reverberates across the Alberta economy. Not only is provincial oil production being scaled back, bruised confidence hampers business investment and consumer spending. The hit will leave a deeper mark than we previously anticipated.*

Economic conditions deteriorated markedly since the fall in Alberta. There have even been signs of contraction early this year as provincial government-mandated cuts in oil production took hold, cash-conscious energy producers sliced capital spending (active drilling rigs plummeted by 32%), and the provincial housing market slumped. The souring of sentiment spread beyond the energy sector. Consumers have had little inclination to make trips to shopping malls, and even less to car dealerships (new motor vehicle sales fell nearly 6% from a year ago in the first quarter). They saw the slow recovery in the labour market stall in the opening months of 2019, which no doubt gave them reason to pause.

This turn of events is a setback after the Alberta economy grew for a second-straight year in 2018 at the respectable rate of 2.1%. There were encouraging signs that engineering construction finally turned a corner, and that the manufacturing and services sectors were gaining traction.

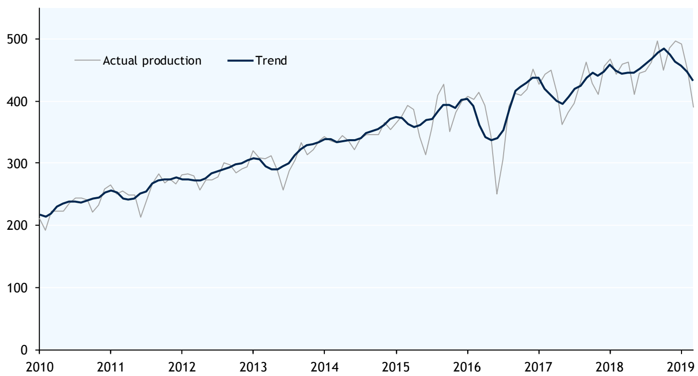
Not all is lost. Mandated oil production cuts are already easing. The Alberta government twice rolled back part of the initial 325,000 barrels per day reduction imposed on large producers of crude oil and bitumen by a total of 150,000 barrels per day. Oil prices received by Alberta producers have bounced back from last fall's crisis levels, which has improved cash flows and the prospects for capital spending in the industry. This likely was a factor in small business confidence soaring in April and May. Recent housing market statistics lead us to believe that the cyclical bottom has been reached in Calgary and Edmonton. This augurs well for home prices to stabilize, market confidence to be restored and housing construction to pick up later this year. We see tentative signs that the labour market's dry spell is ending. April job numbers showed a strong 21,400 gain, which we believe will mark a turning point.

And the announcement in May of a cut in the corporate income tax rate from 12% to 8% over four years by the new UCP government is poised to stoke business investment in the province. The first one-percentage point cut will take effect this July 1st and will be followed by an equal-sized reductions on January 1, 2020, 2021 and 2022.

All considered, we believe that Alberta's economy will be able to get past its rough start to 2019 and stay in the positive growth column this year. That said, we have revised down our projected growth rate from 1.3% to 0.6% on evidence that the turbulence since the fall left a deeper mark than we previously anticipated.

**Alberta: Non-conventional oil production**

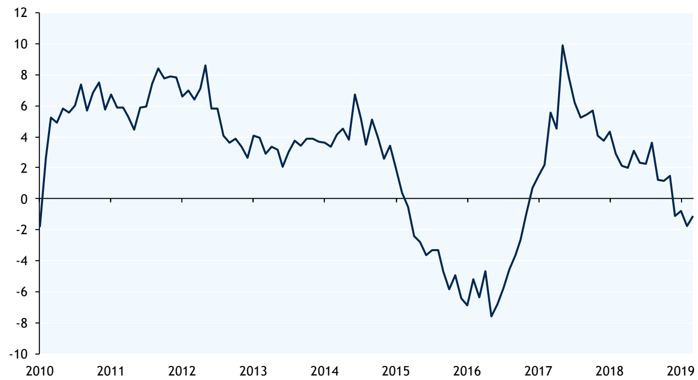
Thousand cubic metres per day




Source: National Energy Board, RBC Economic Research

**Alberta Activity Index**

Year-over-year % change




Source: Alberta Treasury Board and Finance, RBC Economic Research

## Alberta forecast at a glance

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | -4.2 | 4.4 | 2.1 | 0.6 | 2.4 |
| Nominal GDP | -6.8 | 10.0 | 4.4 | 0.6 | 5.5 |
| Employment | -1.6 | 1.0 | 1.9 | 0.9 | 1.1 |
| Unemployment Rate (%) | 8.1 | 7.8 | 6.6 | 6.8 | 6.4 |
| Retail Sales | -1.1 | 7.1 | 2.0 | 3.5 | 3.9 |
| Housing Starts (Thousands of Units) | 24.5 | 29.5 | 26.1 | 24.4 | 26.5 |
| Consumer Price Index | 1.1 | 1.5 | 2.5 | 1.9 | 1.9 |

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# SASKATCHEWAN – Weak growth expected

*Struggling energy sector, trade issues hampering agriculture spell for slower growth ahead. Yet labour market is hanging in.*

The Saskatchewan economy continued to recover in 2018, with GDP growing for the second-straight year (1.4%). Goods-producing industries led the way with crop production rebounding modestly, oil and gas extraction advancing further (despite substantial volatility in energy prices in the latter part of the year) and manufacturing activity growing strongly for a second-straight year. Indicators are mixed so far in 2019. Our outlook for the Saskatchewan economy calls for slower growth (1.2%) in 2019, in part due to the indefinite shutdown of the McArthur River uranium mine. Trade uncertainties and dry weather conditions pose downside risks, having affected crop planting intentions. We expect some of these pressures to lessen and project the provincial economy to grow by 2.2% in 2020.

The Saskatchewan labour market is finally picking up after a disappointing 0.4% rise in 2018. Employment rose an impressive 1.8% so far in 2019 and the unemployment rate fell sharply to 4.9% in March leaving the average year-to-date rate at 5.4%. Wages kept pace with the national average at 2.0% in Q1 2019.

The agriculture sector seems to have had a mixed start. While farm cash receipts are up 4.5% in the first quarter of 2019, exports of crops are down 6.6%. China has restricted access to its canola market in the last two months, by revoking import licenses of the two largest exporters, ostensibly due to concerns regarding pest infestations. This poses a risk to Saskatchewan farmers. The 2019 March Field Crop Survey by Statistics Canada expects farmers to plan 11.7 million acres of canola in 2019 – down 5.6% from 2018. Seeding of lentils has likewise fallen 8% as a result of an ongoing tariff on exports to India.

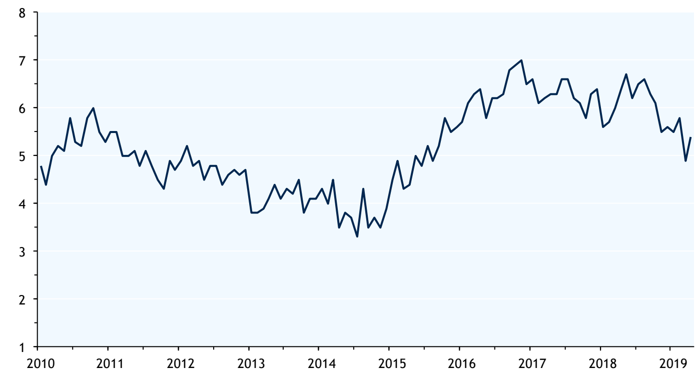
The demographic situation in the province isn't much to write home about. Population growth slowed slightly to 1% in Q1, from 1.2% a year ago. Saskatchewan has been losing people to other provinces since 2012, with the largest out migration recorded last year since 2004.

Another sector weighing on growth is housing. Residential construction investment fell 5% in the first quarter of 2019 with all of this decline in multi-unit dwellings, due to high unsold inventories. Housing starts fell significantly as well, with year to date numbers suggesting a 10 year low.

The outlook for the energy and non-energy mining sectors is mixed. Mineral sales were up this year rising 39% in Q1 2019, thanks to a surge in potash sales. Uranium sales, however, fell 19.6% and a positive outlook is bleak due to the indefinite shutdown of the major uranium producer in the province. The outlook for oil drilling activity is expected to be lower this year with oil production in the region still bumping up against stretched pipeline transportation capacity.

**Saskatchewan: Unemployment rate**

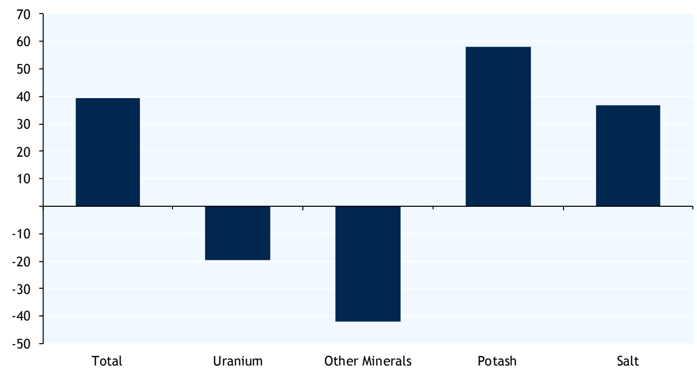
Seasonally adjusted, %




Source: Statistics Canada, RBC Economic Research

**Mineral sales by commodity**

Year-over-year % change, Q1 2019




Source: Saskatchewan Ministry of Energy and Resources, RBC Economic Research

## Saskatchewan forecast at a glance

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | -0.4 | 2.2 | 1.4 | 1.1 | 2.2 |
| Nominal GDP | -4.8 | 4.8 | 4.2 | 2.6 | 4.9 |
| Employment | -0.9 | -0.2 | 0.4 | 1.4 | 0.6 |
| Unemployment Rate (%) | 6.3 | 6.3 | 6.1 | 5.6 | 5.6 |
| Retail Sales | 1.5 | 4.1 | -0.3 | 1.8 | 3.3 |
| Housing Starts (Thousands of Units) | 4.8 | 4.9 | 3.6 | 2.8 | 5.0 |
| Consumer Price Index | 1.1 | 1.7 | 2.3 | 1.9 | 2.6 |

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# MANITOBA – Steady as she goes

*After a weak end to 2018, things are looking more upbeat – particularly in the labour market.*

Manitoba's economy expanded 1.3% in 2018 as a consequence of lower mining output and weather related crop production weakness. While mining activity will continue to be subdued in 2019, strong labour markets and work on some private capital investment projects should accelerate growth slightly to 1.5%. 2020 will see GDP grow at 1.6%.

After a strong rise in exports last year of 12%, numbers were pretty much flat so far in Q1 2019. Digging deeper, while exports to the U.S. increased 7.8% in 2019, non-US exports declined. While there has been a lot of protectionist sentiment in the recent past, we see the outlook for exports to be positive as some trade restrictions have been lifted. The potential ratification of the CUSMA (NAFTA replacement) could further develop bilateral US-Canada trade relations. Additionally, the CPTPP coming into force this year will support Manitoba in diversifying its export markets.

Job creation has been strong in Manitoba in the first quarter of 2019, with employment rising 1.8% from a year ago. Goods sector employment has bounced back to a new high, led by a surge in manufacturing jobs and record high construction employment. The unemployment rate fell to 5.3% year-to-date through April from 6% in the same period last year. Wage growth was still modest at 2.5% in the first quarter of 2019 but above the Canadian average of 2.0%.

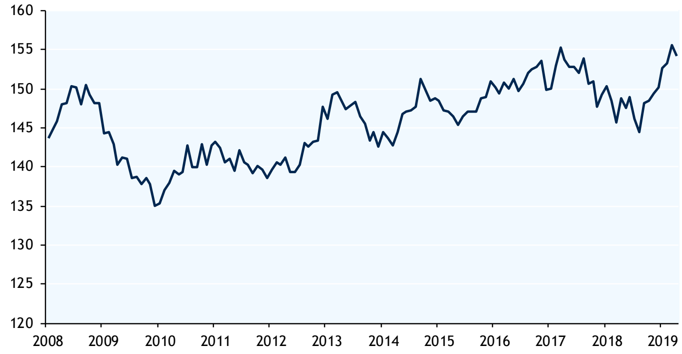
Consumer spending hasn't seen big gain. After growing 2.9% in 2018, retail sales in the first quarter of 2019 saw an increase of just 0.7% from a year prior. In the recent budget, the provincial government introduced a measure that will see a reduction of the Retail Sales Tax rate from 8% to 7%. The tax cut, slated to begin on July 1st 2019, should provide some support to retail sales growth in the latter half of the year.

Capital expenditures are set to decline overall. Most of the drop in spending is concentrated in the utilities sector with winding down of the BiPole III project. Private sector spending, on the other hand, will increase by 4.5%. Work on some capital projects will ramp up this year – including construction on the largest pea processing plant in the world which is slated to open for production in Q4 2020, as well as an extension to a potato processing plant that will begin production in the fall of 2019. Non-residential construction investment has also seen strength (6.5%), mainly from building of industrial and commercial structures.

Crop receipts declined in 2018 due to lower commodity prices as well as bad weather affecting output. This year is also off to a slow start amidst dry conditions, with farm cash receipts declining 5.4% in Q1 2019. We see scope for a turnaround if weather conditions improve.

**Manitoba: Employment in goods-producing sector**

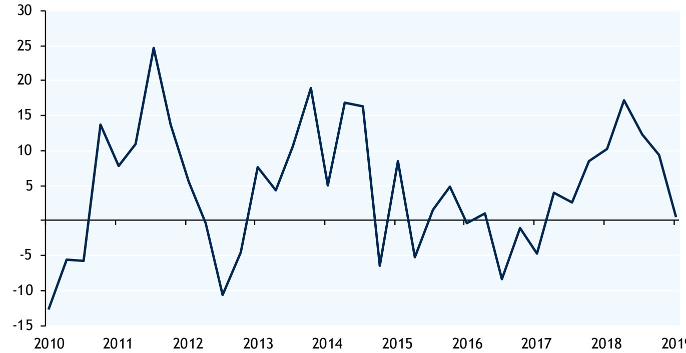
Thousands, seasonally adjusted




Source: Statistics Canada, RBC Economics Research

**Manitoba: Exports**

Year-over-year % change, quarterly




Source: Statistics Canada, RBC Economics Research

## Manitoba forecast at a glance

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.6 | 3.2 | 1.3 | 1.5 | 1.6 |
| Nominal GDP | 2.3 | 5.4 | 2.7 | 2.3 | 3.8 |
| Employment | -0.4 | 1.7 | 0.6 | 1.5 | 0.6 |
| Unemployment Rate (%) | 6.1 | 5.4 | 6.0 | 5.3 | 5.7 |
| Retail Sales | 3.7 | 7.8 | 2.9 | 1.6 | 2.9 |
| Housing Starts (Thousands of Units) | 5.3 | 7.5 | 7.4 | 6.0 | 5.5 |
| Consumer Price Index | 1.3 | 1.6 | 2.5 | 2.1 | 2.2 |

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# ONTARIO – Housing downturn leaves a mark

*The sharp cooling of Ontario's housing market is taking a toll on provincial growth. With little else to pick up the slack, 2019 will mark the first material growth slowdown in six years.*

The downturn in the Toronto-area housing market finally caught up with Ontario's economy in the late stages of 2018. Plummeting residential investment was a key factor contributing to growth slowing down below 1% in the fourth quarter—the first such occurrence since mid-2016. The provincial economy still ended up expanding at the respectable rate of 2.2% in 2018 as a whole (thanks to impressive vigour mid-year). But the hand-off to 2019 clearly was weak. And with the housing market slump carrying over to the initial months of 2019, the sluggish economic pace has persisted. This soft patch will affect growth overall in 2019, which we now forecast to moderate to a six-year low of 1.4%.

The drop in residential investment wasn't a surprise. The writing was on the wall the moment provincial and federal policy makers took action in 2017 and at the start of 2018 to cool overheated housing markets in southern Ontario. The effect on the home resale market was nearly immediate but it took until the fall of 2018 for new home construction to gear down in a material way. After contributing 0.4 percentage points to the average 2.5% provincial growth rate between 2015 and 2017, residential investment subtracted 0.4 percentage points in 2018. This included an outsized 1.3 percentage-point drag on annualized growth in the fourth quarter (which finished at just 0.6%).

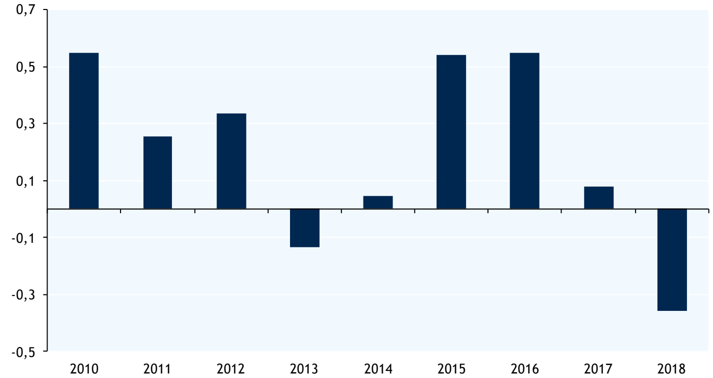
We expect the housing-related drag to ease in the remainder of 2019. Signs of a resale market bottom have emerged this spring and housing construction picked up recently. Yet we see little scope for a material rebound in residential investment this year or next. Severe affordability issues will continue to restrain housing demand in the Toronto area and shift activity toward lower-priced units.

Non-residential investment has been a generally positive—albeit volatile—factor for Ontario's economy and we expect this to continue in 2019. The successful conclusion of the NAFTA renegotiations (provided the tentative agreement is ratified) and recent elimination of tariffs on Canadian steel and aluminum exports to the US should boost business confidence to invest in the province. Private and public organizations in fact plan to increase their capital spending for a third consecutive year. We are especially encouraged by a recent upswing in machinery and equipment investment. We believe that this will go a long way toward addressing significant labour shortage issues in the province.

The outlook for household spending is mixed. A persistently tight labour market is poised to generate more meaningful income gains at some point. However, past interest rate increases are still filtering down to borrowers and putting a squeeze on highly indebted Ontarians. Rising debt service costs will restrain spending budgets for big ticket, discretionary items.

**Ontario: Residential investment**

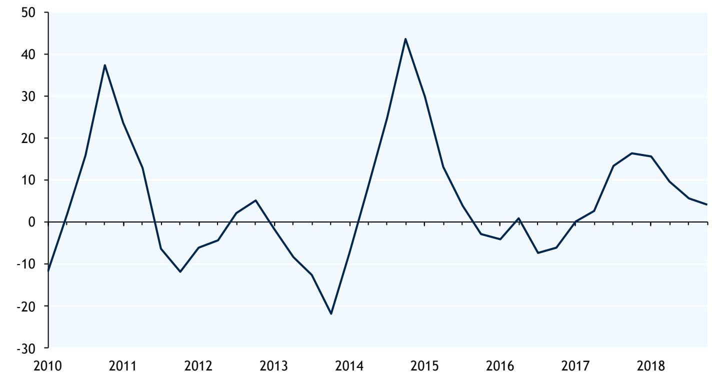
Contribution to change, percentage points




Source: Ontario Ministry of Finance, RBC Economic Research

**Ontario: Business investment in machinery and equipment**

Year-over-year % change




Source: Ontario Ministry of Finance, RBC Economic Research

**Ontario forecast at a glance**

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 2.3 | 2.8 | 2.2 | 1.4 | 1.6 |
| Nominal GDP | 4.4 | 4.1 | 3.4 | 3.4 | 3.5 |
| Employment | 1.1 | 1.8 | 1.6 | 2.2 | 0.7 |
| Unemployment Rate (%) | 6.5 | 6.0 | 5.6 | 5.9 | 6.0 |
| Retail Sales | 6.9 | 7.7 | 4.4 | 2.3 | 3.5 |
| Housing Starts (Thousands of Units) | 75.0 | 79.1 | 78.7 | 73.1 | 71.0 |
| Consumer Price Index | 1.8 | 1.7 | 2.4 | 1.9 | 2.1 |

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# QUEBEC - A new economic powerhouse?

*Quebec emerged as one of the more vibrant provincial economies over the past two years. 2019 is shaping up to be no different with most industrial sectors in expansion mode. We project growth to exceed the national average for a second-straight year.*

Not that long ago Quebec's economy was stuck in the slow lane. Declining working-age population, weak business investment and lagging labour productivity significantly restrained growth. Between 2012 and 2016, Quebec's GDP growth consistently ranked in the bottom half of the provincial rankings, averaging just 1.2%. Things turned around in a big way in 2017 when the provincial economy recorded its strongest advance in 15 years (2.8%). A number of factors came together—including exceptionally low interest rates, successive provincial budget surpluses, an immigration wave and a thriving housing market—that boosted confidence across the province. Businesses went on a hiring spree and increased capital spending.

The good times continued to roll in 2018. Preliminary estimates place Quebec's GDP growth rate (2.4%) second behind only Prince Edward Island (2.5%). The broad-based expansion—all major industrial sectors grew last year—kept the labour market very tight. Quebec's unemployment rate fell to its lowest level (5.5%) in more than 40 years. This led to a sharp rise in the number of positions going unfilled. In fact, recruiting and retaining labour last year was one of the top challenges facing businesses.

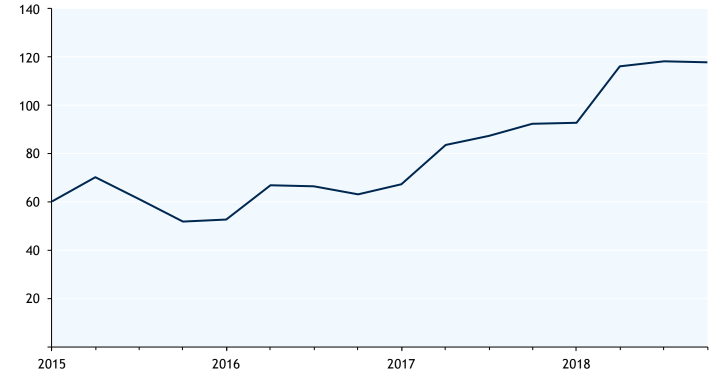
We see little that would throw Quebec's economy off its faster track in the near term. Momentum remains impressive at this stage with monthly GDP estimates from the Institut de la statistique du Québec running close to 3% above year ago levels. Most industrial sectors—including manufacturing, construction, and retail and wholesale trade—had a solid first quarter of 2019. After stalling briefly late last year, hiring resumed in the initial months of 2019 despite the pool of job seekers shrinking. The unemployment rate drifted lower to 4.9% in April.

More importantly, Quebec's growth renaissance is being supported by improved economic fundamentals. A wave of immigrants and non-permanent residents has stemmed the decline in the working-age population—now growing for the first time since 2012. And labour productivity growth has accelerated thanks in part to a material rise in business capital investment in the past couple of years. Solid capital spending intentions this year bode well for these gains to be sustained. We believe that strong momentum and improved fundamentals will keep Quebec near the top of the provincial growth rankings this year with a rate of 2.0%. This would be more than 0.5 percentage points above the national average for the second-straight year.

Whether this qualifies Quebec as an economic powerhouse is debatable. What's undeniable is that the impressive growth spurt is doing wonders to the Quebec government's books. Strong revenue tracking has prompted the government to boost its 2018-2019 projected budget surplus to $3.6 billion—by far the largest on record in dollar terms. Staying out of the slow lane will keep the fiscal affairs in good standing.

**Quebec: Job vacancies**

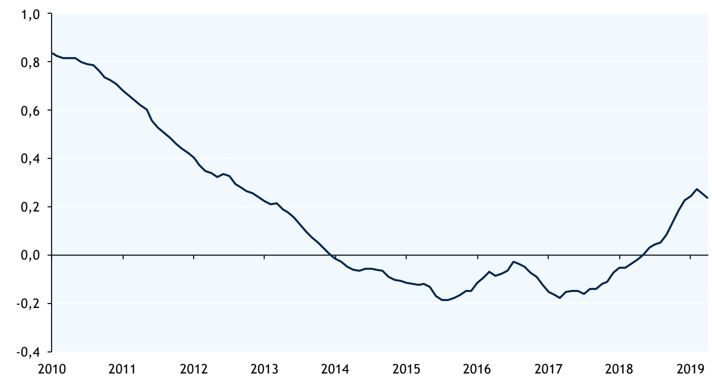
Thousands, quarterly




Source: Statistics Canada, RBC Economic Research

**Quebec: Working-age population (15-64)**

Year-over-year % change, monthly




Source: Statistics Canada, RBC Economic Research

**Quebec forecast at a glance**

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.4 | 2.8 | 2.4 | 2.0 | 1.6 |
| Nominal GDP | 2.8 | 5.0 | 4.5 | 3.8 | 3.4 |
| Employment | 0.9 | 2.2 | 0.9 | 1.6 | 0.7 |
| Unemployment Rate (%) | 7.1 | 6.1 | 5.5 | 5.3 | 5.6 |
| Retail Sales | 6.6 | 5.5 | 2.9 | 2.9 | 3.4 |
| Housing Starts (Thousands of Units) | 38.9 | 46.5 | 46.9 | 48.5 | 43.5 |
| Consumer Price Index | 0.7 | 1.1 | 1.7 | 1.9 | 2.1 |

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# NEW BRUNSWICK - Staying in the slow lane

*Softness in exports and manufacturing sector are weighing on the economic growth, and capital spending remains weak. Labour market has displayed strength to begin the year.*

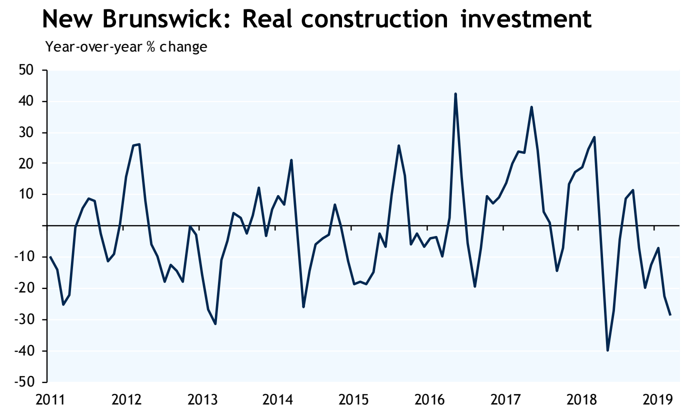
New Brunswick's economy barely budged in 2018, growing by just 0.2%. The goods-producing sector in particular experienced a slowdown with major industries contracting within the sector. An explosion at the refinery in Saint John in Q4 2018 slowed petroleum product production and restrained export growth. This provided a weak base from which to start 2019. We expect growth to expand by 0.8% in 2019 as the refinery resumes normal function. 2020 will see the province grow by 0.9% in 2020.

Construction investment also saw a pullback of 19.7% from a year ago in Q1 2019, with declines in both residential and non-residential structures. The public sector will also provide limited support. The provincial government has committed fewer dollars to capital spending in order to rein in provincial debt.

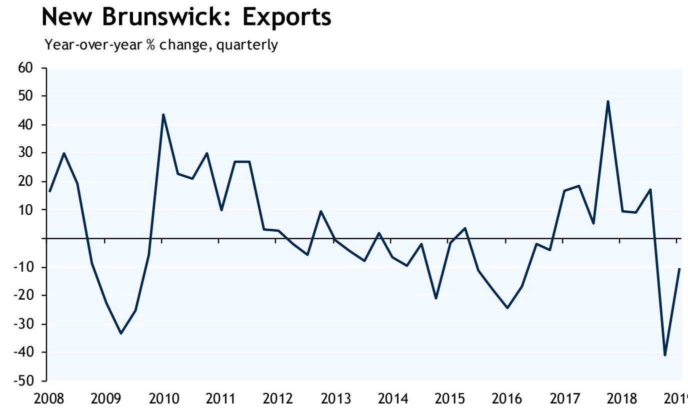
Both the labour force and employment have been making good gains so far in 2019. The labour force expanded at 0.6% in the first four months of the year while employment grew 0.8%. The services sector led the growth in employment, reaching a decade high level in March 2019. The unemployment rate has remained flat at 8.2%. The job vacancy rate reached a new high at the end of 2018 (3%). Like other regions, wage growth has been softer than would normally be expected given ostensibly tight labour markets, but 2.0% average hourly earnings growth year-to-date is in line with the Canadian average.

Like many provinces, New Brunswick saw record high immigration levels last year. Not only that, immigration was the sole contributor to population growth in 2018. While the growth in 2019 has continued at the same pace as the previous year (0.5%), the province would need to see bigger waves of immigration to compensate for older workers leaving the workforce. Else, New Brunswick's aging population will continue to be a limiting factor when it comes to GDP growth.

Manufacturing and trade have been a damper on growth prospects. Manufacturing shipments are down 13.4% in 2019 led by non-durable goods. Exports are also down 10.3% led by petroleum products and lumber. While activity has picked up since the explosion, repairs to the Saint John facility will continue to curtail growth in refined oil products in 2019. The softwood lumber dispute with the United States has also adversely affected lumber exports – which fell 18% in Q1 2019.




Source: Statistics Canada, RBC Economics Research




Source: Statistics Canada, RBC Economics Research

**New Brunswick forecast at a glance**

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.4 | 1.8 | 0.2 | 0.8 | 0.9 |
| Nominal GDP | 3.6 | 4.3 | 1.2 | 2.1 | 2.4 |
| Employment | -0.1 | 0.4 | 0.3 | 0.7 | 0.3 |
| Unemployment Rate (%) | 9.6 | 8.1 | 8.0 | 7.9 | 7.5 |
| Retail Sales | 2.1 | 6.8 | 1.7 | 3.9 | 3.7 |
| Housing Starts (Thousands of Units) | 1.8 | 2.3 | 2.3 | 2.0 | 2.3 |
| Consumer Price Index | 2.2 | 2.3 | 2.2 | 1.8 | 2.2 |

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# NOVA SCOTIA - Sailing along

*The Nova Scotia economy hasn't run out of steam after five consecutive years of growth. While the drivers of growth continue to contribute in 2019, lower capital investment will temper the increase.*

Nova Scotia's economy ended 2018 on solid footing with 1.2% growth, just shy of the 1.5% advance in 2017. An inflow of international and interprovincial immigrants provided solid underpinnings. Population growth reached a 34-year high. This, along with a strong job market, boosted housing demand. 2019 will retain some of that momentum seen in the last few years, however growth will be limited by a pullback in business investment. We expect the provincial economy to expand by 0.9% in both 2019 and 2020.

The labour market in 2019 is off to a sprightly start. Employment surged 2.3% in the first four months of 2019. The monthly labour market numbers are notoriously volatile, but this is an impressive feat for a province that hasn't experienced such growth on an annual basis since 2004. Growth was relatively broad based with 10 out of 16 sectors expanding. Employment in the goods sector reached a six-year high in March. The unemployment rate also fell by a percentage point to average 6.6% and hit the lowest point in March at 6.2%. This strength also made its way to labour income, with average weekly earnings increasing 3.4% - the fastest growth in the country so far in 2019.

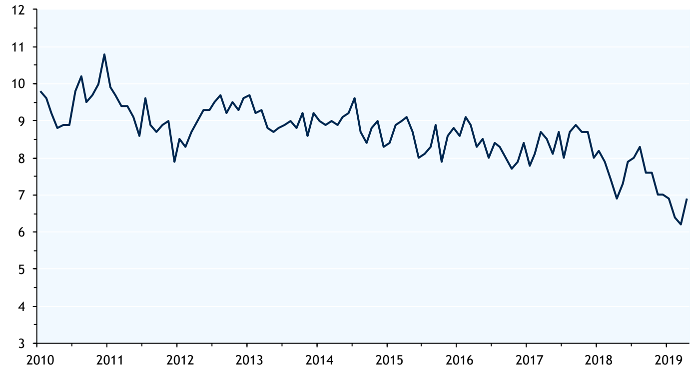
Population growth is continuing at the strong pace set in 2018, accelerating over 1% for the first time since 1985. This, combined with a strong labour market, is boosting retail sales growth – which saw a 2.6% rise in the first quarter compared to just 0.3% in all of 2018. A big part of the increase came from the motor vehicles component, which saw an 11% surge.

There was also strength in the external side of the economy in Q1 2019 with exports growing 6.4%. This was led by sales of consumer goods and farm, fishing and intermediate food products. Amidst trade tensions, Nova Scotia has made efforts to diversify its export partners by launching the Nova Scotia-Europe Engagement Strategy. Exports to China also grew 31.5% in 2018 to reach a new high, led by seafood exports.

Nova Scotia saw the sharpest decline in non-residential investment intentions among the provinces with a projected dip of 6%, led by a pullback in public sector spending (17.6%) while private sector spending ticked up (3%). However, there is good news on the residential construction spending side which grew 11% in the first quarter. The housing market is quite hot, particularly in Halifax. Stronger home building should serve to alleviate some of the housing related supply constraints, since all of the growth was in multi-unit dwellings. This is again a boon to Halifax, which saw its rental vacancy rate dip to multi year lows in 2018 at 1.6%.

**Nova Scotia: Unemployment rate**

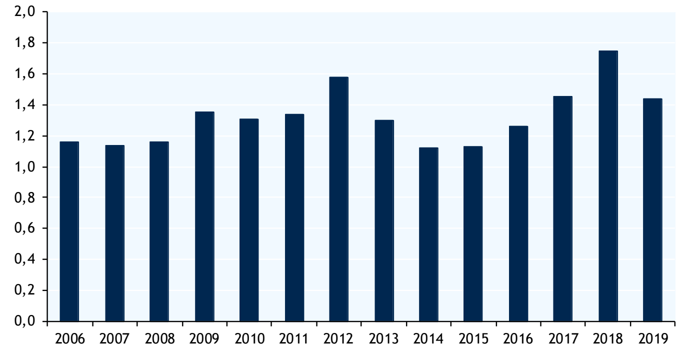
Seasonally adjusted, monthly, %




Source: Statistics Canada, RBC Economic Research

**Nova Scotia: Public sector capital expenditures**

C$ billions, annual




Source: Statistics Canada, RBC Economics Research

## Nova Scotia forecast at a glance

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.5 | 1.5 | 1.2 | 0.9 | 0.9 |
| Nominal GDP | 2.2 | 2.9 | 2.2 | 2.6 | 2.6 |
| Employment | -0.4 | 0.6 | 1.5 | 1.9 | 0.6 |
| Unemployment Rate (%) | 8.3 | 8.4 | 7.6 | 7.1 | 7.2 |
| Retail Sales | 4.7 | 7.8 | 0.3 | 2.2 | 3.0 |
| Housing Starts (Thousands of Units) | 3.8 | 4.0 | 4.8 | 4.1 | 3.8 |
| Consumer Price Index | 1.2 | 1.1 | 2.2 | 1.6 | 2.3 |

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# PRINCE EDWARD ISLAND – On a winning streak

*Rapidly-growing population, flourishing labour market, steady export gains and a vibrant manufacturing sector—clearly Prince Edwards Island's economy still has a lot going for it in 2019*

PEI's economy continues to impress having beat our growth expectations in 2018 by leading the nation with rate of 2.5%. Given that this was the second-straight year that growth exceeded the national average, one might expect the pace to slow down in 2019. Yet indicators for the first quarter of 2019 showed population growth was still strong while manufacturing sales and exports were solid. Accordingly, we have boosted our 2019 GDP forecast for the province from 1.7% to 2.2%. We project growth to moderate slightly to 2.0% in 2020.

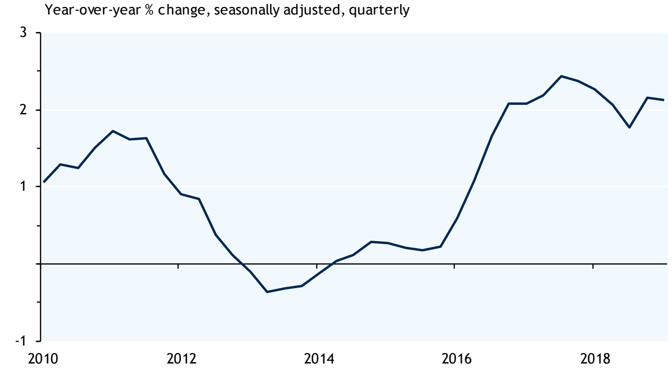
External demand continues to provide much of the wind in PEI's sail. Exports were up almost 10% in the first quarter, thanks primarily to strong deliveries in the aerospace sector. We see scope for other export commodities to contribute positively later this year as improved weather conditions should reverse recent declines in farm, fishing and intermediate food products exports.

Strong immigration bolstered PEI's population growth which beat all other provinces in the last two years in percentage terms. This trend is continuing with the province's population growing 2.1% in Q1 2019 and still leading the country. The wave of immigrants is helping to address the growing demands from employers given that PEI had the second highest rate of job vacancies in Canada at the end of last year. Employment rose 1.4% in the first four months of 2019, with all of the jobs created being full-time positions. The unemployment rate has also been steadily trending down and is currently tracking 9.2% - the lowest level since 1976! Given the tightness of the labour market and high job vacancy rate, conditions are ripe for wage growth to accelerate following a period of subpar gains in recent months.

The improving demographic and labour market backdrop is supporting consumer spending which continued to rise in 2019. Retail sales rose 2.4% in the first quarter buoyed by a whopping 24% jump in new motor vehicle sales, setting PEI apart from Canada's other provinces.

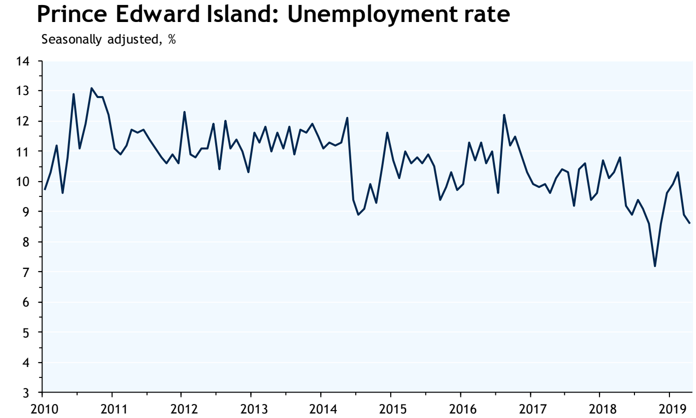
The strong economic underpinnings of the province have delivered handsomely on the fiscal side. While the provincial election means the province hasn't yet tabled its 2019 budget, the latest fiscal update showed a surplus of $13.8 million - nine times higher than previously estimated ($1.5 million). Against the backdrop of another solid year for the economy, all signs point to the province maintaining strong fiscal health in the budget for 2019.

**Prince Edward Island: Population growth**




Source: Statistics Canada, RBC Economics Research

**Prince Edward Island: Unemployment rate**




Source: Statistics Canada, RBC Economic Research

**Prince Edward Island forecast at a glance**

% change unless otherw ise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.8 | 3.5 | 2.5 | 2.2 | 2.0 |
| Nominal GDP | 4.5 | 4.8 | 3.3 | 4.2 | 4.0 |
| Employment | -2.2 | 3.1 | 3.0 | 1.8 | 1.2 |
| Unemployment Rate (%) | 10.8 | 9.8 | 9.4 | 8.9 | 8.6 |
| Retail Sales | 7.3 | 6.3 | 2.9 | 3.5 | 3.2 |
| Housing Starts (Thousands of Units) | 0.6 | 0.9 | 1.1 | 0.7 | 0.8 |
| Consumer Price Index | 1.2 | 1.8 | 2.3 | 1.0 | 2.3 |

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# NEWFOUNDLAND & LABRADOR - Encouraging start to year bodes well for a return to growth in 2019

*Springing back up from an economic contraction in 2018, the province will see a rebound in its resource sector - driving exports higher and supporting a welcome improvement in the labour market*

The winding down of major capital projects and a lower mining output caused Newfoundland and Labrador's economy to contract significantly (-2.7%) in 2018. The good news is that 2019 has already shown signs of a reversal of fortunes, with oil production rising and the labour market off to a sturdy start. We expect the provincial economy to expand by 2.6% in 2019 followed by a more subdued rate of 0.2% in 2020.

The resource sector, which has been a mixed bag for the province in recent years, looks poised to deliver good things in 2019. Oil production is up 4.3% in Q1 2019 as Hebron continues to ramp up to full capacity (150,000 bpd). Energy products are also behind the growth in exports – which rose 9.3% in Q1 2019. Mining shipments are set to increase, after a labour strike at the Iron Ore Company of Canada reduced provincial output last year. This will be accompanied by a 12% rise in capital expenditures by the mining, quarrying, oil and gas extraction industry reflecting growing construction at Vale's Voisey's Bay nickel mine and the West White Rose offshore oil project.

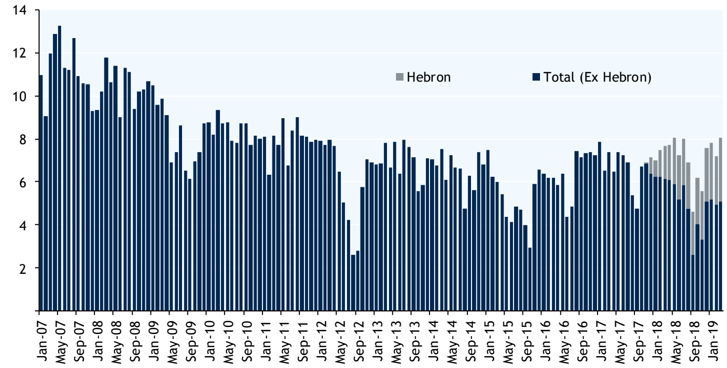
The winding down of construction at the Muskrat Falls facility (96% complete at the end of 2018), however, will weigh significantly on overall capital expenditures in the province, which are slated to drop for a fourth-consecutive year in 2019.

The provincial labour market started 2019 on a surprisingly strong note. Employment is up by more than 3% from a year ago with full-time positions representing the bulk of the increase. The unemployment rate is trending down, reaching its lowest point (11.3%) in four years in January. We now expect Newfoundland and Labrador's annual unemployment rate to fall below 12% for only the second time ever in 2019. So far, the improvement in the labour market has had a limited impact on consumer spending but we expect things to pick up modestly going forward. One factor that continues to be a thorn on the province's side is demographics. Newfoundland and Labrador is the only province with a declining population. This is due primarily to the significant loss of migrants to other provinces and low immigration levels compared to other parts of Canada.

The recently renewed Atlantic Accord saw the federal government handing an unexpected one-time $2.5 billion transfer to the province this fiscal year. This allowed the provincial government to project a $1.9 billion surplus in its 2019-2020 budget while delaying previously-announced program spending cuts by a year. Fiscal restraint will return over the remaining three years of the fiscal plan, however.

**Newfoundland & Labrador: Monthly oil production**

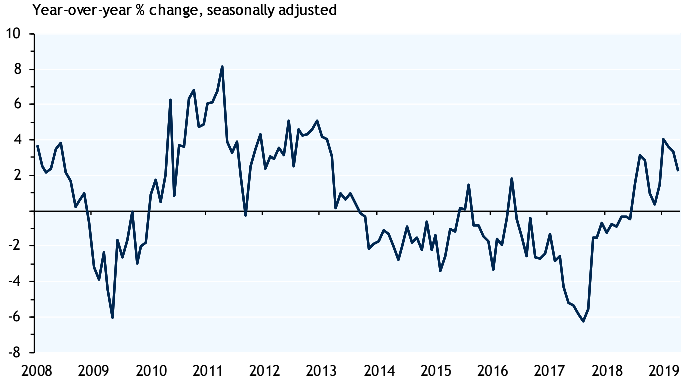
Millions of bbls/month.




Source: Canada Newfoundland & Labrador Offshore Petroleum Board, RBC Economics Research

**Newfoundland & Labrador: Total employment**

Year-over-year % change, seasonally adjusted



Source: Statistics Canada, RBC Economics Research

**Newfoundland and Labrador forecast at a glance**

% change unless otherwise specified

| | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|
| Real GDP | 1.8 | 0.9 | -2.7 | 2.6 | 0.2 |
| Nominal GDP | 1.8 | 4.3 | 2.9 | 4.2 | 2.0 |
| Employment | -1.5 | -3.7 | 0.5 | 1.5 | -0.6 |
| Unemployment Rate (%) | 13.4 | 14.8 | 13.8 | 12.1 | 12.5 |
| Retail Sales | 0.4 | 2.4 | -2.3 | 3.9 | 3.6 |
| Housing Starts (Thousands of Units) | 1.4 | 1.4 | 1.1 | 0.8 | 1.4 |
| Consumer Price Index | 2.7 | 2.4 | 1.7 | 1.2 | 2.2 |

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### Forecast details

% change unless otherwise indicated

| | Real GDP | | | | Nominal GDP | | | | Employment | | | | Unemployment | | | | Housing starts | | | | Retail sales | | | | CPI | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 17 | 18F | 19F | 20F | 17 | 18F | 19F | 20F | 17 | 18 | 19F | 20F | 17 | 18 | 19F | 20F | 17 | 18 | 19F | 20F | 17 | 18 | 19F | 20F | 17 | 18 | 19F | 20F |
| N.& L. | 0.9 | -2.7 | 2.6 | 0.2 | 4.3 | 2.9 | 4.2 | 2.0 | -3.7 | 0.5 | 1.5 | -0.6 | 14.8 | 13.8 | 12.1 | 12.5 | 1.4 | 1.1 | 0.8 | 1.4 | 2.4 | -2.3 | 3.9 | 3.6 | 2.4 | 1.7 | 1.2 | 2.2 |
| P.E.I | 3.5 | 2.5 | 2.2 | 2.0 | 4.8 | 3.3 | 4.2 | 4.0 | 3.1 | 3.0 | 1.8 | 1.2 | 9.8 | 9.4 | 8.9 | 8.6 | 0.9 | 1.1 | 0.7 | 0.8 | 6.3 | 2.9 | 3.5 | 3.2 | 1.8 | 2.3 | 1.0 | 2.3 |
| N.S. | 1.5 | 1.2 | 0.9 | 0.9 | 2.9 | 2.2 | 2.6 | 2.6 | 0.6 | 1.5 | 1.9 | 0.6 | 8.4 | 7.6 | 7.1 | 7.2 | 4.0 | 4.8 | 4.1 | 3.8 | 7.8 | 0.3 | 2.2 | 3.0 | 1.1 | 2.2 | 1.6 | 2.3 |
| N.B. | 1.8 | 0.2 | 0.8 | 0.9 | 4.3 | 1.2 | 2.1 | 2.4 | 0.4 | 0.3 | 0.7 | 0.3 | 8.1 | 8.0 | 7.9 | 7.5 | 2.3 | 2.3 | 2.0 | 2.3 | 6.8 | 1.7 | 3.9 | 3.7 | 2.3 | 2.2 | 1.8 | 2.2 |
| QUE. | 2.8 | 2.4 | 2.0 | 1.6 | 5.0 | 4.5 | 3.8 | 3.4 | 2.2 | 0.9 | 1.6 | 0.7 | 6.1 | 5.5 | 5.3 | 5.6 | 46.5 | 46.9 | 48.5 | 43.5 | 5.5 | 2.9 | 2.9 | 3.4 | 1.1 | 1.7 | 1.9 | 2.1 |
| ONT. | 2.8 | 2.2 | 1.4 | 1.6 | 4.1 | 3.4 | 3.4 | 3.5 | 1.8 | 1.6 | 2.2 | 0.7 | 6.0 | 5.6 | 5.9 | 6.0 | 79.1 | 78.7 | 73.1 | 71.0 | 7.7 | 4.4 | 2.3 | 3.5 | 1.7 | 2.4 | 1.9 | 2.1 |
| MAN. | 3.2 | 1.3 | 1.5 | 1.6 | 5.4 | 2.7 | 2.3 | 3.8 | 1.7 | 0.6 | 1.5 | 0.6 | 5.4 | 6.0 | 5.3 | 5.7 | 7.5 | 7.4 | 6.0 | 5.5 | 7.8 | 2.9 | 1.6 | 2.9 | 1.6 | 2.5 | 2.1 | 2.2 |
| SASK. | 2.2 | 1.4 | 1.1 | 2.2 | 4.8 | 4.2 | 2.6 | 4.9 | -0.2 | 0.4 | 1.4 | 0.6 | 6.3 | 6.1 | 5.6 | 5.6 | 4.9 | 3.6 | 2.8 | 5.0 | 4.1 | -0.3 | 1.8 | 3.3 | 1.7 | 2.3 | 1.9 | 2.6 |
| ALTA. | 4.4 | 2.1 | 0.6 | 2.4 | 10.0 | 4.4 | 0.6 | 5.5 | 1.0 | 1.9 | 0.9 | 1.1 | 7.8 | 6.6 | 6.8 | 6.4 | 29.5 | 26.1 | 24.4 | 26.5 | 7.1 | 2.0 | 3.5 | 3.9 | 1.5 | 2.5 | 1.9 | 1.9 |
| B.C. | 3.8 | 2.3 | 2.4 | 2.5 | 6.9 | 4.6 | 4.5 | 4.7 | 3.7 | 1.1 | 2.5 | 0.7 | 5.1 | 4.7 | 4.9 | 5.0 | 43.7 | 40.9 | 39.8 | 35.0 | 9.3 | 2.0 | 3.0 | 3.5 | 2.1 | 2.7 | 2.2 | 1.8 |
| **CANADA** | **3.0** | **1.9** | **1.4** | **1.8** | **5.6** | **3.6** | **3.2** | **4.0** | **1.9** | **1.3** | **1.9** | **0.7** | **6.3** | **5.8** | **5.9** | **6.0** | **220** | **213** | **202** | **195** | **7.1** | **2.9** | **2.7** | **3.5** | **1.6** | **2.3** | **1.9** | **2.1** |

### Key provincial comparisons

(2017 unless otherwise stated)

| | Canada | NL | PE | NS | NB | QC | ON | MB | SK | AB | BC |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Population (000s) | **37,059** | 525 | 153 | 960 | 771 | 8,390 | 14,323 | 1,352 | 1,162 | 4,307 | 4,992 |
| Gross domestic product ($ billions) | **2,137.5** | 33.1 | 6.7 | 42.7 | 36.1 | 417.2 | 825.8 | 71.0 | 79.5 | 331.9 | 282.2 |
| Real GDP ($2012 billions) | **2,016.4** | 33.8 | 6.1 | 39.5 | 32.9 | 383.1 | 761.3 | 66.6 | 85.5 | 336.8 | 256.9 |
| Share of provincial GDP of Canadian GDP (%) | **100.0** | 1.6 | 0.3 | 2.0 | 1.7 | 19.6 | 39.1 | 3.3 | 3.7 | 14.9 | 13.0 |
| Real GDP growth (CAGR, 2012-17, %) | **2.0** | 1.1 | 1.7 | 0.8 | 0.7 | 1.6 | 2.3 | 2.2 | 1.9 | 1.5 | 3.0 |
| Real GDP per capita ($ 2012) | **55,184** | 63,967 | 40,241 | 41,508 | 42,924 | 46,175 | 54,103 | 49,870 | 74,329 | 79,353 | 52,188 |
| Real GDP growth rate per capita (CAGR, 2013-18, %) | **0.8** | -0.4 | 0.6 | 0.7 | 0.5 | 1.1 | 1.2 | 0.5 | -0.2 | -0.8 | 1.5 |
| Personal disposable income per capita ($) | **32,300** | 31,996 | 28,997 | 28,978 | 29,261 | 28,785 | 32,645 | 29,603 | 32,973 | 36,705 | 34,976 |
| Employment growth (CAGR, 2013-18, %) | **1.1** | -1.5 | 0.5 | 0.1 | 0.0 | 1.0 | 1.2 | 0.7 | 0.2 | 0.9 | 1.9 |
| Employment rate (Apr. 2019, %) | **62.1** | 51.9 | 60.9 | 57.7 | 56.5 | 61.7 | 61.4 | 63.2 | 65.3 | 66.9 | 62.8 |
| Discomfort index (inflation + unemp. rate, Apr. 2019) | **7.7** | 13.2 | 9.8 | 8.2 | 9.7 | 6.7 | 7.9 | 7.5 | 7.7 | 8.9 | 7.3 |
| Manufacturing industry output (% of GDP) | **10.4** | 4.6 | 10.5 | 7.6 | 11.0 | 14.0 | 12.2 | 9.7 | 6.1 | 8.3 | 7.1 |
| Personal expenditures on goods & services (% of GDP) | **56.4** | 51.3 | 67.7 | 71.4 | 64.8 | 58.3 | 57.4 | 57.2 | 47.4 | 46.5 | 63.7 |
| International exports (% of GDP) | **31.0** | 33.8 | 24.1 | 17.1 | 38.9 | 28.1 | 34.5 | 23.8 | 39.5 | 32.8 | 23.8 |

## Forecast Details

% change unless otherwise specified

**British Columbia**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 2.5 | 2.2 | 3.7 | 2.1 | 3.2 | 3.8 | 2.3 | 2.4 | 2.5 |
| Nominal GDP | 2.1 | 3.4 | 5.7 | 2.9 | 6.0 | 6.9 | 4.6 | 4.5 | 4.7 |
| Employment | 1.6 | 0.1 | 0.6 | 1.2 | 3.2 | 3.7 | 1.1 | 2.5 | 0.7 |
| Unemployment Rate (%) | 6.8 | 6.6 | 6.1 | 6.2 | 6.0 | 5.1 | 4.7 | 4.9 | 5.0 |
| Retail Sales | 1.9 | 2.8 | 6.3 | 7.0 | 7.7 | 9.3 | 2.0 | 3.0 | 3.5 |
| Housing Starts (Thousands of Units) | 27.5 | 27.1 | 28.4 | 31.4 | 41.8 | 43.7 | 40.9 | 39.8 | 35.0 |
| Consumer Price Index | 1.1 | -0.1 | 1.0 | 1.1 | 1.9 | 2.1 | 2.7 | 2.2 | 1.8 |

**Alberta**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 3.9 | 5.7 | 5.9 | -3.7 | -4.2 | 4.4 | 2.1 | 0.6 | 2.4 |
| Nominal GDP | 4.3 | 9.6 | 10.0 | -14.0 | -6.8 | 10.0 | 4.4 | 0.6 | 5.5 |
| Employment | 3.5 | 2.5 | 2.2 | 1.2 | -1.6 | 1.0 | 1.9 | 0.9 | 1.1 |
| Unemployment Rate (%) | 4.6 | 4.6 | 4.7 | 6.0 | 8.1 | 7.8 | 6.6 | 6.8 | 6.4 |
| Retail Sales | 6.9 | 7.2 | 7.9 | -4.0 | -1.1 | 7.1 | 2.0 | 3.5 | 3.9 |
| Housing Starts (Thousands of Units) | 33.4 | 36.0 | 40.6 | 37.3 | 24.5 | 29.5 | 26.1 | 24.4 | 26.5 |
| Consumer Price Index | 1.1 | 1.4 | 2.6 | 1.2 | 1.1 | 1.5 | 2.5 | 1.9 | 1.9 |

**Saskatchewan**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 1.7 | 6.5 | 2.0 | -0.9 | -0.4 | 2.2 | 1.4 | 1.1 | 2.2 |
| Nominal GDP | 4.2 | 6.7 | -0.4 | -3.9 | -4.8 | 4.8 | 4.2 | 2.6 | 4.9 |
| Employment | 2.4 | 3.1 | 1.0 | 0.5 | -0.9 | -0.2 | 0.4 | 1.4 | 0.6 |
| Unemployment Rate (%) | 4.7 | 4.1 | 3.8 | 5.0 | 6.3 | 6.3 | 6.1 | 5.6 | 5.6 |
| Retail Sales | 7.3 | 5.2 | 4.7 | -3.3 | 1.5 | 4.1 | -0.3 | 1.8 | 3.3 |
| Housing Starts (Thousands of Units) | 10.0 | 8.3 | 8.3 | 5.1 | 4.8 | 4.9 | 3.6 | 2.8 | 5.0 |
| Consumer Price Index | 1.6 | 1.4 | 2.4 | 1.6 | 1.1 | 1.7 | 2.3 | 1.9 | 2.6 |

**Manitoba**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 3.0 | 2.9 | 2.1 | 1.2 | 1.6 | 3.2 | 1.3 | 1.5 | 1.6 |
| Nominal GDP | 6.4 | 4.2 | 3.1 | 2.6 | 2.3 | 5.4 | 2.7 | 2.3 | 3.8 |
| Employment | 1.6 | 0.7 | 0.1 | 1.6 | -0.4 | 1.7 | 0.6 | 1.5 | 0.6 |
| Unemployment Rate (%) | 5.3 | 5.4 | 5.4 | 5.6 | 6.1 | 5.4 | 6.0 | 5.3 | 5.7 |
| Retail Sales | 1.0 | 3.8 | 4.2 | 1.3 | 3.7 | 7.8 | 2.9 | 1.6 | 2.9 |
| Housing Starts (Thousands of Units) | 7.2 | 7.5 | 6.2 | 5.5 | 5.3 | 7.5 | 7.4 | 6.0 | 5.5 |
| Consumer Price Index | 1.6 | 2.3 | 1.8 | 1.2 | 1.3 | 1.6 | 2.5 | 2.1 | 2.2 |

**Ontario**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 1.3 | 1.4 | 2.5 | 2.5 | 2.3 | 2.8 | 2.2 | 1.4 | 1.6 |
| Nominal GDP | 3.1 | 2.2 | 4.4 | 4.6 | 4.4 | 4.1 | 3.4 | 3.4 | 3.5 |
| Employment | 0.7 | 1.8 | 0.8 | 0.7 | 1.1 | 1.8 | 1.6 | 2.2 | 0.7 |
| Unemployment Rate (%) | 7.9 | 7.6 | 7.3 | 6.8 | 6.5 | 6.0 | 5.6 | 5.9 | 6.0 |
| Retail Sales | 1.6 | 2.7 | 5.7 | 5.3 | 6.9 | 7.7 | 4.4 | 2.3 | 3.5 |
| Housing Starts (Thousands of Units) | 76.7 | 61.1 | 59.1 | 70.2 | 75.0 | 79.1 | 78.7 | 73.1 | 71.0 |
| Consumer Price Index | 1.4 | 1.1 | 2.3 | 1.2 | 1.8 | 1.7 | 2.4 | 1.9 | 2.1 |

## Forecast Details

% change unless otherwise specified

**Quebec**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 1.0 | 1.3 | 1.6 | 0.9 | 1.4 | 2.8 | 2.4 | 2.0 | 1.6 |
| Nominal GDP | 2.7 | 3.0 | 3.0 | 2.9 | 2.8 | 5.0 | 4.5 | 3.8 | 3.4 |
| Employment | 0.8 | 1.4 | 0.0 | 0.9 | 0.9 | 2.2 | 0.9 | 1.6 | 0.7 |
| Unemployment Rate (%) | 7.7 | 7.6 | 7.7 | 7.6 | 7.1 | 6.1 | 5.5 | 5.3 | 5.6 |
| Retail Sales | 1.2 | 3.0 | 2.6 | 1.9 | 6.6 | 5.5 | 2.9 | 2.9 | 3.4 |
| Housing Starts (Thousands of Units) | 47.4 | 37.8 | 38.8 | 37.9 | 38.9 | 46.5 | 46.9 | 48.5 | 43.5 |
| Consumer Price Index | 2.1 | 0.8 | 1.4 | 1.1 | 0.7 | 1.1 | 1.7 | 1.9 | 2.1 |

**New Brunswick**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | -1.1 | -0.3 | 0.1 | 0.7 | 1.4 | 1.8 | 0.2 | 0.8 | 0.9 |
| Nominal GDP | 0.7 | 0.3 | 1.8 | 3.1 | 3.6 | 4.3 | 1.2 | 2.1 | 2.4 |
| Employment | -0.7 | 0.4 | -0.2 | -0.6 | -0.1 | 0.4 | 0.3 | 0.7 | 0.3 |
| Unemployment Rate (%) | 10.2 | 10.3 | 10.0 | 9.8 | 9.6 | 8.1 | 8.0 | 7.9 | 7.5 |
| Retail Sales | -0.9 | 0.7 | 3.7 | 2.2 | 2.1 | 6.8 | 1.7 | 3.9 | 3.7 |
| Housing Starts (Thousands of Units) | 3.3 | 2.8 | 2.3 | 2.0 | 1.8 | 2.3 | 2.3 | 2.0 | 2.3 |
| Consumer Price Index | 1.7 | 0.8 | 1.5 | 0.5 | 2.2 | 2.3 | 2.2 | 1.8 | 2.2 |

**Nova Scotia**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | -1.0 | -0.4 | 1.0 | 0.7 | 1.5 | 1.5 | 1.2 | 0.9 | 0.9 |
| Nominal GDP | 0.5 | 2.1 | 2.9 | 2.2 | 2.2 | 2.9 | 2.2 | 2.6 | 2.6 |
| Employment | 1.0 | -1.1 | -1.1 | 0.1 | -0.4 | 0.6 | 1.5 | 1.9 | 0.6 |
| Unemployment Rate (%) | 9.1 | 9.1 | 8.9 | 8.6 | 8.3 | 8.4 | 7.6 | 7.1 | 7.2 |
| Retail Sales | 0.9 | 3.2 | 2.8 | 0.2 | 4.7 | 7.8 | 0.3 | 2.2 | 3.0 |
| Housing Starts (Thousands of Units) | 4.5 | 3.9 | 3.1 | 3.8 | 3.8 | 4.0 | 4.8 | 4.1 | 3.8 |
| Consumer Price Index | 1.9 | 1.2 | 1.7 | 0.4 | 1.2 | 1.1 | 2.2 | 1.6 | 2.3 |

**Prince Edward Island**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | 1.0 | 1.8 | 0.2 | 1.3 | 1.8 | 3.5 | 2.5 | 2.2 | 2.0 |
| Nominal GDP | 2.7 | 3.2 | 1.7 | 3.9 | 4.5 | 4.8 | 3.3 | 4.2 | 4.0 |
| Employment | 1.7 | 1.4 | -0.1 | -1.2 | -2.2 | 3.1 | 3.0 | 1.8 | 1.2 |
| Unemployment Rate (%) | 11.1 | 11.5 | 10.6 | 10.5 | 10.8 | 9.8 | 9.4 | 8.9 | 8.6 |
| Retail Sales | 3.0 | 0.9 | 3.5 | 2.6 | 7.3 | 6.3 | 2.9 | 3.5 | 3.2 |
| Housing Starts (Thousands of Units) | 0.9 | 0.6 | 0.5 | 0.6 | 0.6 | 0.9 | 1.1 | 0.7 | 0.8 |
| Consumer Price Index | 2.0 | 2.0 | 1.6 | -0.6 | 1.2 | 1.8 | 2.3 | 1.0 | 2.3 |

**Newfoundland and Labrador**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|
| Real GDP | -4.4 | 5.3 | -1.2 | -1.2 | 1.8 | 0.9 | -2.7 | 2.6 | 0.2 |
| Nominal GDP | -4.5 | 7.6 | -0.5 | -9.2 | 1.8 | 4.3 | 2.9 | 4.2 | 2.0 |
| Employment | 3.8 | 0.8 | -1.7 | -1.0 | -1.5 | -3.7 | 0.5 | 1.5 | -0.6 |
| Unemployment Rate (%) | 12.3 | 11.6 | 11.9 | 12.8 | 13.4 | 14.8 | 13.8 | 12.1 | 12.5 |
| Retail Sales | 4.3 | 5.2 | 3.7 | 0.7 | 0.4 | 2.4 | -2.3 | 3.9 | 3.6 |
| Housing Starts (Thousands of Units) | 3.9 | 2.9 | 2.1 | 1.7 | 1.4 | 1.4 | 1.1 | 0.8 | 1.4 |
| Consumer Price Index | 2.1 | 1.7 | 1.9 | 0.4 | 2.7 | 2.4 | 1.7 | 1.2 | 2.2 |

# CIBC Forecast

https://economics.cibccm.com/economicsweb/cds?ID=7649&TYPE=EC_PDF

Note: Unlike other major Canadian banks, CIBC provincial forecasts are not always available. A CIBC forecast was not used in the original forecast.

***ECONOMICS***
*http://economics.cibccm.com*

# Forecast Update

*July 8, 2019*

*Economics (416) 594-7355*

## CANADA FORECAST DETAIL
**(real % change, SAAR, unless otherwise noted)**

| | 18:4A | 19:1F | 19:2F | 19:3F | 19:4F | 20:1F | 20:2F | 20:3F | 20:4F | 2018F | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GDP At Market Prices ($Bn)** | 2,223 | 2,250 | 2,278 | 2,300 | 2,318 | 2,335 | 2,356 | 2,376 | 2,400 | 2,219 | 2,286 | 2,367 |
| % change | -3.1 | 5.0 | 5.0 | 4.0 | 3.2 | 3.0 | 3.6 | 3.5 | 4.1 | 3.6 | 3.0 | 3.5 |
| **Real GDP ($2007 Bn)** | 2,064 | 2,066 | 2,080 | 2,091 | 2,099 | 2,104 | 2,110 | 2,117 | 2,126 | 2,054 | 2,084 | 2,114 |
| % change | 0.3 | 0.4 | 2.8 | 2.0 | 1.6 | 0.9 | 1.2 | 1.3 | 1.7 | 1.9 | 1.4 | 1.4 |
| **Final Domestic Demand** | -1.0 | 3.4 | 2.3 | 1.5 | 1.5 | 1.1 | 1.4 | 1.8 | 1.7 | 2.0 | 1.4 | 1.5 |
| **Household Consumption** | 1.0 | 3.5 | 2.3 | 1.4 | 1.5 | 0.9 | 1.3 | 1.9 | 1.8 | 2.1 | 2.0 | 1.4 |
| **Total Govt. Expenditures** | -0.3 | 2.8 | 1.8 | 1.4 | 1.4 | 1.7 | 1.9 | 1.7 | 1.4 | 3.0 | 1.7 | 1.6 |
| **Residential Construction** | -10.4 | -6.1 | 3.4 | -0.7 | -1.2 | -0.8 | -1.1 | -0.2 | 1.0 | -1.5 | -3.5 | -0.5 |
| **Business Fixed Investment*** | -6.3 | 10.4 | 2.8 | 3.7 | 3.5 | 2.2 | 2.8 | 3.0 | 2.4 | 2.2 | 1.0 | 2.9 |
| **Inventory Change ($2007 Bn)** | 13.9 | 17.7 | 9.5 | 8.0 | 7.0 | 7.5 | 7.5 | 6.4 | 6.2 | 12.7 | 10.6 | 6.9 |
| **Exports** | 0.3 | -4.1 | 8.0 | 4.7 | 2.9 | 2.1 | 1.8 | 1.3 | 2.2 | 3.2 | 2.0 | 2.8 |
| **Imports** | -0.7 | 7.7 | 1.2 | 2.1 | 2.1 | 2.9 | 2.5 | 2.3 | 2.1 | 2.9 | 1.6 | 2.3 |
| **GDP Deflator** | -3.3 | 4.5 | 2.2 | 1.9 | 1.6 | 2.0 | 2.4 | 2.2 | 2.4 | 1.7 | 1.6 | 2.1 |
| **CPI (yr/yr % chg)** | 2.0 | 1.6 | 2.2 | 2.0 | 2.3 | 2.5 | 1.7 | 1.8 | 2.1 | 2.3 | 2.0 | 2.0 |
| **Unemployment Rate (%)** | 5.7 | 5.8 | 5.5 | 5.8 | 5.9 | 6.1 | 6.2 | 6.2 | 6.3 | 5.8 | 5.8 | 6.2 |
| **Employment Change (K)** | 100 | 133 | 138 | 17 | 8 | 16 | 23 | 27 | 34 | 238 | 365 | 104 |
| **Goods Trade Balance (AR, $bn)** | -31.8 | -36.6 | -21.3 | -11.4 | -9.6 | -11.2 | -12.5 | -15.6 | -18.4 | -22.0 | -19.7 | -14.4 |
| **Housing Starts (AR, K)** | 217 | 187 | 208 | 188 | 180 | 181 | 177 | 174 | 171 | 214 | 191 | 176 |

* M&E plus Non-Res Structures and Intellectual Property and NPISH

CIBC

## US FORECAST DETAIL
**(real % change, SAAR, unless otherwise noted)**

| | 18:4A | 19:1A | 19:2F | 19:3F | 19:4F | 20:1F | 20:2F | 20:3F | 20:4F | 2018A | 2019F | 2020F |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GDP At Market Prices ($Bn)** | 20,865 | 21,060 | 21,258 | 21,436 | 21,635 | 21,833 | 22,035 | 22,255 | 22,476 | 20,494 | 21,347 | 22,150 |
| % change | 4.1 | 3.8 | 3.8 | 3.4 | 3.8 | 3.7 | 3.7 | 4.1 | 4.0 | 5.2 | 4.2 | 3.8 |
| **Real GDP ($2009 Bn)** | 18,765 | 18,910 | 18,987 | 19,037 | 19,100 | 19,166 | 19,238 | 19,325 | 19,415 | 18,566 | 19,009 | 19,286 |
| % change | 2.2 | 3.1 | 1.6 | 1.1 | 1.3 | 1.4 | 1.5 | 1.8 | 1.9 | 2.9 | 2.4 | 1.5 |
| **Final Sales** | 2.1 | 2.6 | 3.0 | 0.9 | 1.2 | 1.1 | 1.9 | 1.8 | 2.1 | 2.7 | 2.2 | 1.5 |
| **Personal Consumption** | 2.5 | 0.9 | 3.7 | 0.6 | 1.9 | 1.4 | 2.6 | 2.1 | 2.0 | 2.6 | 2.3 | 1.9 |
| **Total Govt. Expenditures** | -0.4 | 2.8 | 1.1 | 0.9 | 0.6 | -2.0 | -1.6 | -0.5 | 0.0 | 1.5 | 1.5 | -0.6 |
| **Residential Investment** | -4.7 | -2.0 | 1.2 | 0.8 | 0.7 | -1.0 | -0.4 | -0.2 | -0.1 | -0.3 | -1.6 | -0.1 |
| **Business Fixed Investment** | 5.4 | 4.4 | 1.1 | 1.0 | 2.4 | 3.7 | 3.6 | 3.5 | 4.1 | 6.9 | 3.4 | 2.9 |
| **Inventory Change ($2009 Bn)** | 96.8 | 122.8 | 58.6 | 67.5 | 75.5 | 87.2 | 70.4 | 72.0 | 60.9 | 45.0 | 81.1 | 72.6 |
| **Exports** | 1.8 | 5.4 | 1.2 | 3.0 | 2.7 | 2.1 | 1.9 | 1.7 | 2.4 | 4.0 | 2.3 | 2.2 |
| **Imports** | 2.0 | -1.9 | 0.6 | 1.6 | 5.4 | 1.7 | 2.2 | 1.8 | 1.2 | 4.5 | 1.6 | 2.4 |
| **GDP Deflator** | 1.7 | 0.9 | 2.1 | 2.3 | 2.4 | 2.3 | 2.2 | 2.2 | 2.1 | 2.2 | 1.8 | 2.3 |
| **CPI (yr/yr % chg)** | 2.2 | 1.6 | 1.8 | 1.8 | 2.2 | 2.7 | 2.2 | 2.2 | 2.0 | 2.4 | 1.9 | 2.3 |
| **Core CPI (yr/yr % chg)** | 2.2 | 2.1 | 2.1 | 2.2 | 2.3 | 2.3 | 2.4 | 2.2 | 2.0 | 2.1 | 2.2 | 2.2 |
| **Unemployment Rate (%)** | 3.8 | 3.9 | 3.6 | 3.8 | 3.9 | 4.1 | 4.1 | 4.1 | 4.0 | 3.9 | 3.8 | 4.1 |
| **Housing Starts (AR, K)** | 1,185 | 1,213 | 1,260 | 1,235 | 1,220 | 1,206 | 1,193 | 1,184 | 1,177 | 1,250 | 1,232 | 1,190 |

## PROVINCIAL FORECAST DETAIL

**(real % change, SAAR, unless otherwise noted)**

| | Real GDP Y/Y % Chg | | | Nominal GDP Y/Y % Chg | | | Employment Y/Y % Chg | | | Unemployment Rate % | | | Housing Starts 000s Units | | | Consumer Price Index Y/Y % Chg | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2018E | 2019F | 2020F | 2018F | 2019F | 2020F | 2018A | 2019F | 2020F | 2018A | 2019F | 2020F | 2018A | 2019F | 2020F | 2018A | 2019F | 2020F |
| BC | 2.1 | 1.6 | 2.1 | 3.9 | 3.3 | 4.1 | 1.1 | 2.6 | 0.9 | 4.7 | 4.6 | 4.9 | 40.9 | 42.0 | 36.0 | 2.7 | 2.3 | 2.1 |
| Alta | 2.1 | 0.6 | 1.8 | 4.1 | 1.7 | 4.1 | 1.9 | 0.8 | 0.6 | 6.6 | 6.9 | 7.0 | 26.1 | 25.0 | 26.0 | 2.5 | 2.0 | 2.1 |
| Sask | 1.4 | 0.8 | 1.3 | 3.4 | 1.9 | 3.3 | 0.4 | 1.6 | 0.3 | 6.1 | 5.4 | 5.8 | 3.6 | 3.0 | 4.0 | 2.3 | 2.0 | 2.0 |
| Man | 1.1 | 1.6 | 1.5 | 2.9 | 3.2 | 3.5 | 0.6 | 1.2 | 0.3 | 6.0 | 5.4 | 5.8 | 7.4 | 7.0 | 7.0 | 2.5 | 2.3 | 2.0 |
| Ont | 2.0 | 1.7 | 1.3 | 3.7 | 3.4 | 3.3 | 1.6 | 2.6 | 0.7 | 5.6 | 5.7 | 6.2 | 78.7 | 64.0 | 61.0 | 2.4 | 1.9 | 2.1 |
| Qué | 2.3 | 1.9 | 1.5 | 3.9 | 3.5 | 3.5 | 0.9 | 1.4 | 0.5 | 5.5 | 5.3 | 5.7 | 46.9 | 42.0 | 35.0 | 1.7 | 2.1 | 1.9 |
| NB | 0.0 | 0.8 | 0.6 | 1.7 | 2.4 | 2.6 | 0.3 | 0.8 | 0.0 | 8.0 | 8.1 | 8.3 | 2.3 | 2.0 | 2.0 | 2.2 | 1.7 | 1.9 |
| NS | 1.0 | 1.4 | 1.2 | 2.7 | 3.0 | 3.2 | 1.5 | 2.0 | 0.6 | 7.5 | 6.7 | 6.9 | 4.8 | 4.0 | 3.0 | 2.2 | 1.5 | 1.8 |
| PEI | 2.4 | 0.9 | 1.0 | 4.1 | 2.5 | 3.0 | 3.1 | 1.3 | 0.3 | 9.4 | 9.3 | 9.5 | 1.1 | 0.8 | 0.8 | 2.3 | 1.0 | 2.0 |
| N&L | -2.9 | 1.9 | -0.6 | -0.9 | 3.4 | 1.6 | 0.5 | 2.2 | 0.2 | 13.8 | 11.9 | 11.9 | 1.1 | 1.0 | 1.0 | 1.7 | 1.2 | 1.8 |
| **Canada** | **1.9** | **1.4** | **1.4** | **3.6** | **3.0** | **3.5** | **1.3** | **2.0** | **0.6** | **5.8** | **5.8** | **6.2** | **214** | **191** | **176** | **2.3** | **2.0** | **2.0** |

*Sources: CIBC, Statistics Canada, CMHC*

# COMMODITIES FORECAST DETAIL

| | | 2017 | 2018 | 2019 (f) | 2020 (f) |
|---|---|---|---|---|---|
| Oil (WTI) | $/bbl | 51 | 65 | 57 | 60.5 |
| Natural Gas (Henry) | $/Mn Btu | 3.02 | 3.07 | 2.68 | 3.08 |
| Gold* | $/troy oz | 1303 | 1269 | 1390 | 1400 |
| Silver* | $/troy oz | 16.9 | 15.7 | 13.8 | 13.7 |
| Iron Ore (62% Fe) | $/mt | 71 | 66 | 88 | 68 |
| Copper | $/lb | 2.81 | 2.97 | 2.78 | 2.75 |
| Aluminum | $/lb | 0.89 | 0.96 | 0.85 | 0.81 |
| Nickel | $/lb | 4.73 | 5.96 | 5.90 | 5.84 |
| Zinc | $/lb | 1.31 | 1.33 | 1.28 | 1.25 |
| Lumber** | $/'000 bd ft | 385 | 462 | 380 | 370 |
| Potash | $/tonne | 218 | 216 | 253 | 266 |

**end of period, **1st CME Futures*

*NB: Above are CIBC Economics' Forecasts, which will differ from pricing assumptions made by CIBC Equity Research Analysts.*

# 3 - OEB Staff - 81

Reference:

Appendix 2-IB

Preamble:

The following table is provided in Appendix 2-IB:

| | Calendar Year (for 2020 Cost of Service | | Consumption (kWh) (3) | | | | |
|---|---|---|---|---|---|---|---|
| | | | | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
| Historical | 2009 | | Actual | 2,381,532,329 | 2,454,693,020 | Board Approved | 2,596,512,398 |
| Historical | 2010 | | Actual | 2,521,864,890 | 2,500,489,529 | | |
| Historical | 2011 | | Actual | 2,500,918,608 | 2,479,507,609 | | |
| Historical | 2012 | | Actual | 2,480,837,615 | 2,477,871,786 | | |
| Historical | 2013 | | Actual | 2,450,616,245 | 2,451,029,476 | | |
| Historical | 2014 | | Actual | 2,463,137,594 | 2,441,447,556 | | |
| Historical | 2015 | | Actual | 2,397,631,611 | 2,405,193,061 | | |
| Historical | 2016 | | Actual | 2,471,215,846 | 2,425,111,572 | | |
| Historical | 2017 | | Actual | 2,367,940,087 | 2,409,664,890 | | |
| Historical | 2018 | | Forecast | | 2,373,403,713 | | |
| Bridge Year | 2019 | | Forecast | | 2,307,487,797 | | |
| Test Year | 2020 | | Forecast | | 2,230,875,607 | | |

| Variance Analysis | Year | Year-over-year | | | Versus Board-approved |
|---|---|---|---|---|---|
| | 2009 | | | | |
| | 2010 | 5.9% | 1.9% | | |
| | 2011 | -0.8% | -0.8% | | |
| | 2012 | -0.8% | -0.1% | | |
| | 2013 | -1.2% | -1.1% | | |
| | 2014 | 0.5% | -0.4% | | |
| | 2015 | -2.7% | -1.5% | | |
| | 2016 | 3.1% | 0.8% | | |
| | 2017 | -4.2% | -0.6% | | |
| | 2018 | | -1.5% | | |
| | 2019 | | -2.8% | | |
| | 2020 | | -3.3% | | |
| | Geometric Mean | -0.1% | -0.9% | | |

OEB staff has also calculated that the Geometric Mean for the weather-normalized actuals from 2009 to 2017 is -0.2%, while the geometric mean growth rate from 2017 weather-normalized actual to 2020 test year weather-normalized forecast is -2.5%.

EnWin Utilities has forecasted a total system consumption with an accelerating decline part of this is accounted for by demand drivers, as estimated through the regression models, and part due to the CDM adjustment to the load forecast. However, the rate of change in the forecasted bridge and test year period is much larger (in a negative sense) than EnWin Utilities has seen over the historical period since 2009.

OEB staff notes that the Government of Ontario issued, on March 20, 2019, Orders-in-Council to the OEB and to the Independent Electricity System Operator (IESO). [Order-in-Council 378/2019 is addressed to the OEB and Order-in-Council 379/2019 is to the IESO.] These Orders-in-Council and the Minister's Directives attached to these change the focus of the existing 2015-2020 CDM framework and shift the delivery of CDM programs from being LDC-led to being centrally-led by the IESO. Existing CDM plans to March 31, 2019 were allowable, as well as CDM programs for 2019 that the LDC had already committed to.

OEB staff has also prepared a separate analysis (Figure 1 below and excel file attached in Appendix 1) based on the above table, but wanting to see what the trend is based on the "weather-normalized actuals". In using the weather-normalized actuals, this starting point assumes measured actuals and EnWin Utilities' weather-normalization of consumption for the applicable customer classes.

**Figure 1: OEB Staff Analysis for Linear Trend of EnWin Utilities' Weather-normalized System Consumption (kWh) based on Appendix 2-IB Data**

| | Calendar Year (for 2020 Cost of Service | | Consumption (kWh) [8] | | | | | P | Q | R | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Actual (Weather actual) | Weather-normalized | | Weather-normalized | Weather-normalized | Ln(Weather-Normalized) | Exp(Ln (Weather-Normalized)) | |
| Historical | 2009 | | Actual | 2,381,532,329 | 2,454,693,020 | Board Approved | 2,596,512,398 | 2,454,693,020 | 21.62126755 | 2,454,693,020 | Actual |
| Historical | 2010 | | Actual | 2,521,864,890 | 2,500,489,529 | | | 2,500,489,529 | 21.63975236 | 2,500,489,529 | Actual |
| Historical | 2011 | | Actual | 2,500,918,608 | 2,479,507,609 | | | 2,479,507,609 | 21.63132583 | 2,479,507,609 | Actual |
| Historical | 2012 | | Actual | 2,480,837,615 | 2,477,871,786 | | | 2,477,871,786 | 21.63066588 | 2,477,871,786 | Actual |
| Historical | 2013 | | Actual | 2,450,616,245 | 2,451,029,476 | | | 2,451,029,476 | 21.61977397 | 2,451,029,476 | Actual |
| Historical | 2014 | | Actual | 2,463,137,594 | 2,441,447,556 | | | 2,441,447,556 | 21.61585696 | 2,441,447,556 | Actual |
| Historical | 2015 | | Actual | 2,397,631,611 | 2,405,193,061 | | | 2,405,193,061 | 21.60089601 | 2,405,193,061 | Actual |
| Historical | 2016 | | Actual | 2,471,215,846 | 2,425,111,572 | | | 2,425,111,572 | 21.60914337 | 2,425,111,572 | Actual |
| Historical | 2017 | | Actual | 2,367,940,087 | 2,409,664,890 | | | 2,409,664,890 | 21.60275352 | 2,409,664,890 | Actual |
| Historical | 2018 | | Forecast | | 2,373,403,713 | | | *2,400,170,412* | *21.5989191* | *2,400,442,859* | *Trend* |
| Bridge Year | 2019 | | Forecast | | 2,307,487,797 | | | *2,390,315,417* | *21.5948932* | *2,390,798,437* | *Trend* |
| Test Year | 2020 | | Forecast | | 2,230,875,607 | | | *2,380,460,422* | *21.5908674* | *2,381,192,765* | *Trend* |

| Variance Analysis | Year | Year-over-year | | Versus Board-approved | Year-over-year | |
|---|---|---|---|---|---|---|
| | 2009 | | | | | |
| | 2010 | 5.9% | 1.9% | | 1.9% | 1.9% |
| | 2011 | -0.8% | -0.8% | | -0.8% | -0.8% |
| | 2012 | -0.8% | -0.1% | | -0.1% | -0.1% |
| | 2013 | -1.2% | -1.1% | | -1.1% | -1.1% |
| | 2014 | 0.5% | -0.4% | | -0.4% | -0.4% |
| | 2015 | -2.7% | -1.5% | | -1.5% | -1.5% |
| | 2016 | 3.1% | 0.8% | | 0.8% | 0.8% |
| | 2017 | -4.2% | -0.6% | | -0.6% | -0.6% |
| | 2018 | | -1.5% | | *-0.4%* | *-0.4%* |
| | 2019 | | -2.8% | | *-0.4%* | *-0.4%* |
| | 2020 | | -3.3% | | *-0.4%* | *-0.4%* |
| | Geometric Mean | -0.1% | -0.9% | | -0.3% | -0.3% |

In the Column labelled P of Appendix 1, staff have used the Excel function TREND to do a simple linear trend to forecast the weather-normalized consumption for the bridge years 2018 and 2019 and the test year 2020 based on the weather-normalized actuals from 2009 to 2017.

In Column Q, staff have calculated first the natural logarithm of the weather-normalized actuals for 2009 to 2017, and then calculated the forecasts of the natural logarithm for 2018 to 2020. In Column R, the logarithmic values in Column Q are exponentiated, using the EXP function, to get raw weather-normalized values based on the mathematical equation that:

$e^{\ln(X)} = X$

The year-over year variances are shown in the sub-table below, and estimates a growth rate of -0.4% per year in the bridge and forecast period.

Question:

a) Please provide the basis for EnWin Utilities' projection for weather-normalized consumption to reduce at a rate of -2.5% for the bridge and test year period and which is a significant (and increasing) acceleration of the consumption reduction relative to historical consumption.

b) Since CDM, both natural and promoted, is in the historical data and would thus be a factor in the historical trend, is, and if so, why is, EnWin Utilities assuming that CDM will have an increasing and accelerating influence on system-wide consumption in the 2018-2020, particularly in light of the changes to the CDM framework per Orders-in-Council 378/2019 and 379/2019.

c) In the trend analysis the staff has prepared, since CDM is factored into the historical data, it is also implicitly factored into the forecasts for the 2018-2020 period. However the assumption is that the influence of CDM on a going-forward basis is similar, relatively speaking to what it has been historically.

i. Please provide EnWin Utilities' views on whether this approach provides a more realistic system-level forecast where, in light of Orders-in-Council 378/2019 and 379/2019, natural and promoted CDM continues but in line with the changed CDM framework focus of the Government of Ontario.

ii. The straight linear trend and the linear trend of the logarithmic approaches produce similar results. The trend of ln(consumption) is more related to geometric growth, similar to compounded interest growth. Please provide EnWin Utilities' views on whether the approach in Column P, of the logarithmic trend in Columns Q-R, would be preferable.

iii. While staff has done this at the system-level, the results would have to be separated into the class-specific consumption and then associated kW demand for demand-billed customer classes. This potentially could be done based on historical or projected class proportions. An alternative approach would be apply a similar TREND analysis for the class-specific weather-normalized actuals. Please provide EnWin Utilities' views on whether applying a trend at the system-level or at class-specific levels is preferred.

d) Based on EnWin Utilities' responses to c), please provide a load forecast estimate of consumption (kWh) and, as applicable, demand (kW) on a system basis and at a class level.

Response:

a) The basis for reduced forecast consumption in 2019 and 2020 was due to the high level of planned CDM at the time the forecast was produced. The level of planned CDM was significantly higher than historic annual CDM so the reduction was more accelerated than historic trends. The CDM forecast has subsequently changed in the updated forecast and the rate of decline of weather normalized consumption is now in line with the historic rate.

b) Within the CDM forecast ENWIN had included savings related to energy efficiency projects placed under contract as part of the former Conservation First Framework, and savings which were based on past participation. These savings were intended to account for activities undertaken within ENWIN's service territory under the IESO's Interim Framework. Following the release of the OEB's addendum to the filing requirements for electricity distribution rate applications[1], ENWIN has since updated its CDM forecast to only include savings subject to a Conservation First Framework contract, thus reducing the impacts of CDM over the period of 2018-2020.

c) i. This method is more realistic than the original forecast given the changes to the CDM framework because forecast CDM is now more in line with historic CDM. However, since ENWIN's level of CDM has been revised to be consistent with the CDM changes it is more reasonable to use this updated forecast than use trends in historic CDM. Class-specific forecast CDM is substantially different from historic CDM.

ii) Both methods implicitly assume CDM will be consistent with historic CDM, which is not the case, so neither are preferable to the forecast provided. Between the two options column R is preferable because changes in consumption at the system level are likely more relative than absolute (i.e. a percentage change rather than consistent kWh change) though the difference is minimal in the short term. Additionally, this method would circumvent the explicit CDM adjustment required for the load forecast.

iii) The results at the class level would be less reflective than the system level. The primary difference between methods is related to forecast CDM. Updated forecast CDM in 2019 and 2020 is somewhat consistent with historic CDM trends at the system level but there are significant differences at the class level. The residential class has historically had approximately 20% of total CDM activity but has no planned activity in 2019 or 2020. All of 2020 planned CDM is for a single program for the Large Use class that has forecast savings greater than total CDM savings in any other year.

[1] Ontario Energy Board, *Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications*, Issued July 15, 2019, section 2.3.1.3 CDM Adjustment for the Load Forecast for Distributors.

d) The calculations in the following tables use the trend of the natural logarithm of weather-normalized consumption in each year. Note that there is no adjustment for the lost customer in these calculations.

| kWh | Total System | Residential | GS<50 kW | GS>50 kW | Intermediate |
|---|---|---|---|---|---|
| 2009 | 2,459,288,678 | 630,707,545 | 229,541,720 | 929,123,776 | 51,306,802 |
| 2010 | 2,500,017,178 | 632,311,052 | 222,953,245 | 935,985,192 | 49,071,888 |
| 2011 | 2,467,780,174 | 628,669,706 | 217,664,155 | 943,202,745 | 48,794,571 |
| 2012 | 2,483,367,967 | 627,043,886 | 216,136,535 | 945,538,430 | 45,768,540 |
| 2013 | 2,458,279,404 | 621,169,656 | 212,662,557 | 942,101,798 | 45,666,584 |
| 2014 | 2,451,958,873 | 617,032,792 | 209,571,368 | 942,346,822 | 47,519,842 |
| 2015 | 2,418,793,450 | 614,929,733 | 206,452,380 | 942,501,868 | 44,363,941 |
| 2016 | 2,436,535,328 | 611,201,705 | 204,884,735 | 944,970,326 | 44,045,564 |
| 2017 | 2,407,017,883 | 597,615,778 | 203,634,326 | 946,698,268 | 44,136,954 |
| 2018 | 2,399,142,447 | 592,076,679 | 204,018,650 | 937,869,078 | 41,120,567 |
| *2019* | *2,396,866,106* | *593,531,016* | *197,889,090* | *946,177,057* | *41,291,133* |
| *2020* | *2,387,680,731* | *589,337,258* | *195,327,254* | *947,117,695* | *40,473,647* |

| kWh | Large Use | Large Use - 3TS | Large Use - FA | Street Light | Sentinel | USL |
|---|---|---|---|---|---|---|
| 2009 | 292,439,562 | 253,823,156 | 50,208,449 | 16,930,328 | 992,473 | 4,214,867 |
| 2010 | 295,810,981 | 287,197,656 | 54,756,020 | 16,997,069 | 953,517 | 3,980,560 |
| 2011 | 300,342,236 | 265,542,338 | 41,936,988 | 17,061,701 | 908,473 | 3,657,260 |
| 2012 | 300,912,994 | 280,858,035 | 45,336,839 | 17,377,866 | 908,923 | 3,485,918 |
| 2013 | 301,585,002 | 265,541,554 | 48,126,675 | 17,283,102 | 887,748 | 3,254,726 |
| 2014 | 301,237,700 | 266,219,490 | 47,308,909 | 17,360,921 | 924,204 | 2,436,825 |
| 2015 | 301,843,895 | 241,052,439 | 47,202,926 | 17,162,408 | 873,074 | 2,410,786 |
| 2016 | 305,112,690 | 264,027,087 | 44,370,767 | 14,655,212 | 851,685 | 2,415,557 |
| 2017 | 309,339,474 | 252,589,950 | 42,875,821 | 6,962,744 | 795,951 | 2,368,616 |
| 2018 | 314,516,690 | 254,635,667 | 45,402,739 | 6,467,781 | 768,232 | 2,266,364 |
| *2019* | *313,073,863* | *251,229,025* | *43,280,137* | *8,297,410* | *774,385* | *1,944,394* |
| *2020* | *315,081,955* | *249,174,913* | *42,698,715* | *7,544,257* | *755,964* | *1,800,486* |

| kW | Total System | GS>50 kW | Intermediate | Large Use | Large Use - 3TS | Large Use - FA | Street Light | Sentinel |
|---|---|---|---|---|---|---|---|---|
| 2009 | 4,078,822 | 2,471,269 | 130,057 | 591,714 | 739,223 | 95,070 | 48,739 | 2,749 |
| 2010 | 3,954,082 | 2,394,134 | 130,266 | 580,655 | 698,063 | 99,529 | 48,810 | 2,624 |
| 2011 | 3,863,955 | 2,443,347 | 130,752 | 585,995 | 574,892 | 77,155 | 49,250 | 2,566 |
| 2012 | 3,806,906 | 2,415,708 | 127,751 | 570,676 | 559,021 | 81,689 | 49,566 | 2,496 |
| 2013 | 3,809,538 | 2,442,786 | 129,021 | 564,445 | 535,816 | 85,551 | 49,480 | 2,439 |
| 2014 | 3,760,718 | 2,405,968 | 131,072 | 560,436 | 524,555 | 86,734 | 49,412 | 2,542 |
| 2015 | 3,721,448 | 2,409,392 | 128,586 | 561,308 | 487,725 | 82,845 | 49,145 | 2,448 |
| 2016 | 3,704,162 | 2,377,928 | 130,216 | 559,642 | 515,987 | 74,822 | 43,203 | 2,365 |
| 2017 | 3,709,818 | 2,421,107 | 133,092 | 567,043 | 495,653 | 70,874 | 19,819 | 2,230 |
| 2018 | 3,668,548 | 2,381,358 | 128,456 | 569,483 | 494,553 | 73,849 | 18,707 | 2,142 |
| *2019* | *3,597,113* | *2,383,036* | *130,150* | *556,059* | *441,309* | *70,303* | *23,926* | *2,161* |
| *2020* | *3,560,400* | *2,377,066* | *130,193* | *553,378* | *423,015* | *68,309* | *21,766* | *2,111* |

## 3 - OEB Staff - 82

Reference:

Exhibit 3, Page 20; Appendix 2-H Other Operating Revenues; Revenue Requirement Work Form

Preamble:

The total other revenues in Table 3-20 of Exhibit 3 and Appendix 2-H for 2020 test year is $4,825,347. Staff notes that the other revenues on the Revenue Requirement Work Form (RRWF) is $4,007,915.

Question:

a) Please update Appendix 2-H using the actual other revenues in 2018.

b) Please explain the discrepancy and provide the updated schedule(s) as necessary.

---

Response:

a) ENWIN has provided an updated Appendix 2-H as requested with 2018 actual other revenues.

b) The RRWF required the addition of USoA 4086 SSS administration revenue, while this charge is not considered other revenue within Appendix 2-H but is collected from customers. Also, the RRWF excluded the one-time gain on sale of the Ouellette Avenue location in 2020.

## 3 - OEB Staff - 83

Reference:

Appendix 2-H Other Operating Revenues

Preamble:

EnWin Utilities did not provide the variance analysis between the 2009 actual and 2009 approved other revenues. Staff calculates the variances between the 2009 approved other revenues and 2009 actual other revenues and noted that the variance is mainly due to the lack of forecast of revenues and expenses of Non-Utility Operations in 2009 CoS application as below:

| Other Revenues Category | 2009 Approved | 2009 Actual | Variance |
|---|---|---|---|
| Distribution Service Revenue (SSS admin charges) | 269,649 | $ - | $ (269,649) |
| Rent from Electric Property | 453,616 | $ 450,701 | $ (2,915) |
| Other Utility Operating Income | - | $ 2,410 | $ 2,410 |
| Late Payment Charges | 979,749 | $ 1,409,969 | $ 430,220 |
| Miscellaneous Service Revenue | 421,473 | 695,962 | $ 274,489 |
| Gain on Disposition on Property | - | 67,300 | $ 67,300 |
| Miscellaneous Non-Operating Revenue | 235,316 | 295,911 | $ 60,595 |
| Foreign Exchange Gain/Loss | - | 1,534 | $ 1,534 |
| Interest and Dividend Income | 84,000 | (183,361) | $ (267,361) |
| Revenues from Non-Utility Operations | 0 | $ 12,506,800 | $ 12,506,800 |
| Expenses of Non-Utility Operations | 0 | $(11,006,320) | $(11,006,320) |
| **Total Other Revenues** | **2,443,803** | **4,240,904** | **1,797,101** |
| **Variance %** | | | **74%** |

Question:

a) Please explain why the revenues and expenses of Non-Utility Operations were not forecasted as part of other revenues in 2009 CoS application?

Response:

a) The 2009 Cost of Service application excluded both the Non-Utility Revenue and Expenses. The exact rationale is unknown but it appears that those operations were viewed as not part of the electricity operations and therefore were not included in the rate application at that time.

   The current application has included those operations and the net revenue from that activity is now being included when calculating the base revenue requirement.

## 3 - OEB Staff - 84

Reference:

Appendix 2-H Other Revenues and Appendix 2-EA Account 1575

Preamble:

OEB staff understands that the transitional adjustments from the CGAAP to MIFRS are accumulated in Account 1575 and the annual adjustment is recorded in Account 4310 Regulatory Credit. OEB staff prepares a reconciliation of the changes in Account 1575 and Account 4310 and notes some discrepancies as below:

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|
| 1575 | (3,382,035) | (4,389,506) | (2,597,508) | (2,265,827) | (1,934,269) | (2,371,364) | (2,280,328) | (2,697,952) | (2,222,271) |
| 4310 | (3,382,035) | (4,389,506) | (2,597,508) | (2,265,827) | (1,934,269) | (2,371,364) | (2,280,328) | (2,216,822) | (2,216,822) |
| difference | - | 0 | 0 | 0 | 0 | 0 | 0 | 481,130 | 5,449 |

Question:

a) Please explain the above two discrepancies in 2018 and 2019.

Response:

ENWIN has provided the updated Chapter 2 Appendices with 2018 actuals, including 2-H and 2-EA. Appendix 2-H for 2019 has also been updated. Those updates have eliminated any discrepancies.

## 3 - OEB Staff - 85

Reference:

Appendix 2-H Other Operating Revenues

Preamble:

OEB staff notes that Account 4210 Rent from Electric Properties of $1,485,454 in 2020 has increased more than double as compared to the rent forecasted in 2019 of $759,211.

Question:

a) Please confirm whether or not this rent represents the pole attachment rental revenues.

i) If so, please provide a breakdown of the forecasted 2020 rent and the forecast 2019 rent into the number of poles and the unit cost.

---

Response:

ENWIN confirms that Account 4210 represents the pole attachment rental revenues. ENWIN assumes in the current application the discontinuation of 1508 sub-account Pole Attachment revenue effective January 1, 2020. Therefore, the per pole rate reflected in Account 4210 for 2020 is $43.63 plus an estimated OEB inflation factor of 1.89%, while 2019 reflects the Board approved $22.35 per pole.

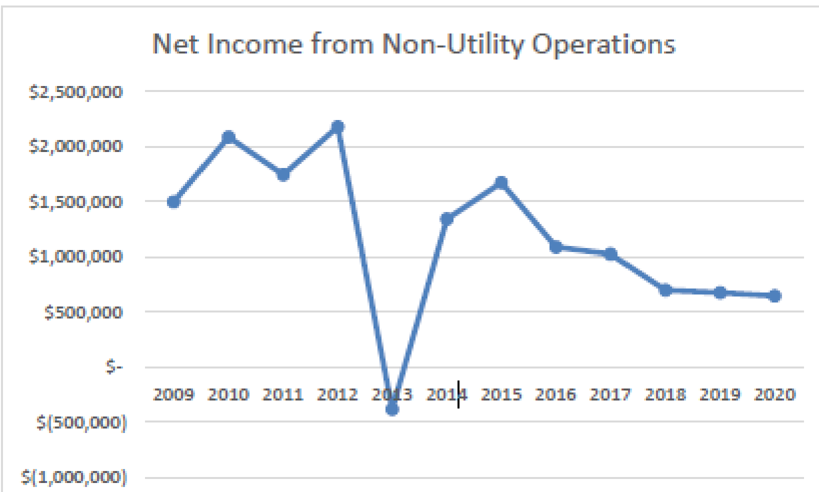
## 3 - OEB Staff - 86

Reference:

Appendix 2-H Other Operating Revenues; Exhibit 3, Page 22

Preamble:

Using the historical and forecast balances in two accounts (Account 4375 Revenues from Non-Utility Operation and Account 4380 Expenses of Non-Utility Operation), staff prepared the following trend graph showing the net income from Non-Utility Operation:




EnWin Utilities states that an additional expense of $1,703,886 was recorded to Account 4380 Expenses of Non- Utility Operations in 2013 because of the undercharging of an affiliate for their appropriate share of employee future benefit expenses.

Question:

1) Please explain why EnWin Utilities undercharged the $1,703,886 to the affiliates for their share of employee future benefit expenses and which prior period(s) is this amount pertaining to.

2) Please explain why the forecast net income from Non-utility operations in 2019 and 2020 significantly decrease from the historical years, as can be seen from the graph.

Response:

1) ENWIN undercharged an affiliate in 2013 specifically for employee future benefit costs. The reason for the undercharge was because 2013 was the first full year when the Water System Operating Agreement became effective. The costs associated with the new shared service ENWIN Utilities Ltd. employees were not properly isolated so those costs were not identified as being shared and as a result were not charged to the affiliate. This became a shareholder expense.

2) The forecasted non-utility operations in 2019 and 2020 are trending lower than historical levels because of a few key factors.

   The first and most significant is the decline in net book value of shared service assets. Several material shared service assets, specifically the ERP (SAP) and billing system (NorthStar) are substantially depreciated by the end of 2020. That is causing a decline in the return on assets charge that is applied to the affiliates. In 2010 ENWIN charged affiliates approximately $1.2 million for a return on assets but in 2020 using the projected net book value of the shared service assets, the return is approximately $630 thousand. The main driver of the change is the decline in net book value of those assets.

   Another factor is that classification of accounts includes revenue recognized from conservation related activities. In 2015 and 2017, the amounts recognized were approximately $487 thousand and $307 thousand. Those activities are not planned to continue into the Test Year and beyond.

   A review was also conducted in 2017 investigating the working capital charge that ENWIN was charging to its affiliates. It was noted that ENWIN was actually utilizing and benefiting from the working capital provided from the affiliates. ENWIN would collect and retain the funds from joint billing and would not remit immediately to the affiliates. The cost allocation model assumed that the affiliates were using ENWIN working capital and therefore charging for that use, but in reality, ENWIN was using the affiliate's funds. Instead of ENWIN paying for the use of the funds, the working capital charge was set to zero within the model. That resulted in a decline in 2017 compared to 2016 of $263 thousand in revenue.

## 3 - OEB Staff - 87

Reference:

Exhibit 3, Attachment 3-D, letter (August 8, 2018)

ENWIN_Exh 3_AttachmentD_CDM Plan Resub Summary of Key Updates_20190426 (excel attachment)

Appendix 2-I of Chapter 2 Appendices

Preamble:

In the letter dated October 1, 2018 in Attachment 3-D, EnWin Utilities requested that the IESO deliver CDM programs for the remainder of the term as its conservation budget of $38.4 million was exhausted. Attachment 3-D notes that 191,141 MWh of savings were expected to be delivered for the remainder of the term.

Question:

a) Please discuss whether there have been any further updates/revisions to EnWin Utilities' CDM Plan that shows continuing programs and savings to the end of the 2015-2020 Conservation First Framework.

b) As EnWin Utilities filed a 6-year target of 151,300 MWh in Appendix 2-I, please discuss whether this reflects all continuing level of energy savings expected for the remainder of the Conservation First Framework. If not, how does this figure reconcile with the remaining CDM projects that EnWin Utilities is contractually obligated to complete under the CFF?

c) Please provide a summary that describes and clearly shows the total number of projects EnWin Utilities is contractually obligated to complete under the CFF, the total amount of projected savings (kWh and kW) and the expected completion date of the final project.

Response:

a) ENWIN confirms that there have not been any further updates to its CDM Plan since it was last approved by the IESO on October 29, 2018. The approved Plan only includes savings related to energy efficiency projects placed under contract by ENWIN as part of the former Conservation First Framework.

b) As detailed in its CDM Plan, ENWIN expects to deliver 191,141 MWh of energy savings as part of the Conservation First Framework. As mentioned above, ENWIN's CDM Plan only contains savings related to projects that are contractually obligated to be completed under the former Conservation First Framework.

Following the release of the OEB's addendum to the filing requirements for electricity distribution rate applications[1], ENWIN has since updated its CDM forecast within Appendix 2-I to only include savings subject to a Conservation First Framework contract.

c) A listing of the remaining projects contractually obligated to be completed under the former Conservation First Framework is attached. Please see OEB Staff 87 – Attachment 1.

[1] Ontario Energy Board, *Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications*, Issued July 15, 2019, section 2.3.1.3 CDM Adjustment for the Load Forecast for Distributors.

## 4 - OEB Staff - 88

Reference:

Exhibit 4, Page 11; Appendix 2-JB OM&A Cost Drivers

Preamble:

One of the OM&A cost drivers in Appendix 2-JB is the information system. EnWin Utilities states that "Information Technology services and purchases increased by $787 thousand over the 11 year period. Since the time of the last rebasing, ENWIN has installed a new customer facing IT system, customer internet portal, meter data management data base (MeterSense), GIS system, and outage management system".

Question:

a) Please explain how the installation of the new IT systems increases the OM&A costs.

---

Response:

a) The installation of new IT systems increase the OM&A costs in 3 main areas: the cost to operate; the cost to support and maintain and the cost to enhance and extend.

Cost to Operate: This is represented by the costs of the infrastructure and operations necessary to allow the application to provide the required level of performance, usability and availability. When infrastructure is purchased for new systems, maintenance is often included in the purchase price so the impact to OM&A is minimal. Operational efficiencies such as buying products compatible with existing technology, using virtual machines with shared resources helps keep OM&A costs for new systems at par to prior years. The exception to this is the SAP implementation in 2010. OM&A costs increased until internal staff were able to learn and absorb the operational tasks.

Cost to Support and Maintain: These are the costs associated with paying software vendors for maintenance and for providing first, second and third-line support for the application. These costs are the main drivers of the increase in OM&A. SAP went live in May 2010 with 3rd party support for 1 year; CIS Billing, Customer Portal and Metersense in 2013 with 3rd party support for CIS; GIS in 2014; and Outage Management including a customer outage map in 2016/2017. All these systems, with the exception of the outage map which is built on the GIS platform, increased licensing fees.

Cost to Enhance and Extend: These are the costs for adding new capabilities for the application, encompassing both major and minor enhancements. The project costs will appear as an investment capex but after implementation, there have been small impacts to OM&A costs. SAP Mobility for field staff, which went live in 2013 and was enhanced in future years to include GIS integration, are examples of these costs.

## 4 - OEB Staff - 89

Reference:

Exhibit 4, Page 11; Appendix 2-JB OM&A Cost Drivers

Preamble:

One of the OM&A cost drivers in Appendix 2-JB is billing and metering outside services. EnWin Utilities provides the explanation as below:

Billing and Metering Services and expenses have increased by approximately $320 thousand as a result of conversion to electronic meter reading and the MDM/R and time of use systems. Previously ENWIN split the costs of manual meter reading with the Windsor Utilities Commission as it was obtaining water usage readings at the same time. Now under the new platform, ENWIN must cover the communication and MDM/R data base costs on its own, resulting in a higher level of cost.

Staff notes from the Appendix 2-JB that $151k out of $320k increase in the billing and metering expenses incurred in 2019 bridge year.

Question:

a) Please reconcile the explanation of the higher costs due to electronic metering and the time of use system with the year of the significant increase in 2019.

Response:

a) The significant increase in 2019 is due to a classification difference. Previously, the MDM/R costs were recorded in professional expenses however those costs were subsequently reallocated to meter reading costs to better reflect the true cost of meter reading. The increase to the organization did occur once time of use pricing was introduced because previously meter reading costs were shared by water and electricity ratepayers.

## 4 - OEB Staff - 90

Reference:

Appendix 2-JB OM&A Cost Drivers

Preamble:

Per the Appendix 2-JB, another cost driver for the OM&A increase is the increase in the property tax. The property tax has increased by $400k in 2020 test year as compared to 2009 approved property tax. EnWin Utilities forecasts $147k increase in 2020 out of the total $400k increase.

Question:

a) Please provide the basis of the forecasted increase of the property tax in 2020.

---

Response:

a) The grouping within Appendix 2-JB is for Property Expenses, which includes a variety of items including building and tool maintenance and utility costs for buildings, but excludes property taxes.

   The Test Year figures were based on historical trending using the most recent information along with any known adjustments. At the time of preparation, the 2017 actual costs for this category totaled $1,585,413 and the 2020 Test Year balance is projected to be $1,716,144 in 2020. That increase of $130,731 represents a CAGR of 2.68%. The increase in utility costs is the main driver within this category.

## 4 - OEB Staff - 91

Reference:

Exhibit 4, Page 13 Appendix 2-IB

Preamble:

EnWin Utilities indicates "[s]tagnant customer growth" as one of the challenges that the utility faced over the 2009-2017 period. However, an analysis by OEB staff of the data provided in Appendix 2-IB provides the following average annual growth rates (measured as the geometric mean growth rate from 2009 to 2017).

**Geometric Mean Annual Growth Rates 2009-2017, from Appendix 2-IB**

| | Customers | kWh (Weather Actual) | kW (Weather Actual) |
|---|---|---|---|
| Residential | 0.5% | -0.5% | |
| GS < 50 kW | 0.3% | -1.5% | |
| GS > 50 kW and Intermediate | 0.9% | 0.3% | -0.1% |
| Large Use - Regular | 0.0% (6 customers throughout period) | 1.4% | -0.1% |
| Large Use – 3TS and Ford Annex | -4.0% (from 4 to 3 customers in 2013) | -0.4% | -5.4% |
| Unmetered Scattered Load | 0.1% | -7.9% | |
| Sentinel Lighting | -2.6% | -3.1% | -3.1% |
| Street Lighting | 0.4% | -11.9% | -12.1% |

Most of the decline is in terms of demand (kWh and kW). A few customer classes do show negative growth, but these classes have relatively few customers and represent only a small fraction of EnWin Utilities' customer base. Residential and GS customer classes show small but positive growth in customers over that period.

Question:

a) Please explain how EnWin Utilities is defining "stagnant customer growth" in Exhibit 4.

Response:

a) At Exhibit 4, page 13, ENWIN cited "stagnant population growth" as one of the issues facing the Windsor business environment over the 2009 – 2017 period. While ENWIN does not have a formal definition of "stagnant customer growth", ENWIN's general use of the term was intended to convey that Windsor's population, which is related to ENWIN's customer base, had not grown in a significant manner over this time period.

## 4 - OEB Staff - 92

Reference:

Exhibit 4, Page 23

Preamble:

EnWin Utilities identifies “[a] one-time write off related to traffic lighting occurred in 2016 in the amount of $137 thousand for the period from 2011-2013” as being a factor in the variance in bad debt expense from 2017 compared to 2016. Customers with traffic lights would typically be municipal or provincial governments or road authorities, who would normally be considered low risk.

Question:

a) Please provide further explanation of the $137,000 write-off related to traffic lighting.

---

Response:

In September 2013 a discrepancy was discovered between the loads reported in ENWIN’s previous billing system, PeopleSoft, and the loads tracked for the approximately 280 traffic signal locations throughout the City of Windsor. As a result, a full, detailed audit was performed. The audit uncovered that 77 of the 280 traffic signal points had incorrect values entered in PeopleSoft due to multiple upgrades/additions to individual traffic signals that were either not updated in ENWIN’s CIS system or not reported to ENWIN by the City of Windsor. Upon completion of the review and in preparation for the NorthStar CIS implementation, all identified discrepancies were corrected in the PeopleSoft system effective January 2014, while a full financial review of the impact of the billing error was underway. This review took place over the next 3 years. The review was complicated due to the City of Windsor being under agreement with a retailer, and ENWIN not having visibility to the contracted retailer charges and further by ENWIN’s position that the re-bill period should be limited to 2 years from the discovery of the error in accordance with the Distribution System Code, and that ENWIN would only compensate for discrepancies that had been communicated to ENWIN by the City of Windsor.

Late in 2016, The City of Windsor and ENWIN finally came to an agreement that between October 2011 and December 2013, ENWIN had overbilled the City of Windsor’s Traffic Light account by 887,660 kWh, which resulted in the $137,000 write-off.

In order to prevent these types of errors from occurring in the future, ENWIN incorporated several risk mitigating factors, including billing the overall monthly consumption and number of connections rather than tracking multiple locations, adding a report to validate and highlight any variances, and creating a dedicated email address to eliminate delays and/or recipient omissions and ensure updates are properly communicated and receive appropriate attention.

## 4 - OEB Staff - 93

Reference:

Exhibit 4, Page 30

Preamble:

EnWin Utilities states the following with respect to Customer Service and Billings:

Customer Service & Billings

| 2017 Actuals | 2020 Test Year | Variance |
|---|---|---|
| $ 1,993,014 | $ 2,358,932 | $ 365,918 |

In 2017, approximately $141,000 for system related costs for meter reading were recorded in administration and general expenses but in 2018 and going forward, those costs are being recorded in the customer service & billing category to better reflect the cost of meter reading. There is also an increase of approximately $158,000 of expenses that were not incurred in 2017 due to vacancies within the call centre that are not expected to occur in the future therefore, the full cost of the call centre approved complement is being budgeted in the 2020 Test Year. Unplanned vacancies that create short term variances are out of the control of ENWIN.

Question:

a) Please provide the following for the customer service & billing expense:

i. 2018 actuals

ii. 2019 Year-to-date actuals

iii. 2019 updated year-end projection

b) Please provide a table showing the variances of the 2020 test year budget compared to the 2018 actuals and the 2019 year-end projection.

c) Was the call centre fully staffed at the end of 2018? Is the call centre fully staffed now? Please provide information on the following:

i. the percentage of call centre staff complement that is vacant, and for how long this situation has persisted

ii. the factors affecting the degree and persistence of understaffing

iii. What efforts EnWin Utilities is undertaking to address the situation?

iv. Why EnWin Utilities believes that it will have a full complement of call centre staff for the 2020 test year?

Response:

a) The Customer service & billing expense breakdown is as follows:

i. 2018 actuals: $2,193,174

ii. 2019 Year-to-date actuals: $1,126,944 as of June 30, 2019

iii. 2019 updated year-end projection: unchanged from budget of $2,300,623

b) Customer Service & Billings

| 2018 Actuals | 2020 Test Year | Variance |
|---|---|---|
| **$ 2,193,174** | **$ 2,358,932** | **$ 165,758** |
| **2019 Projection** | **2020 Test Year** | **Variance** |
| **$ 2,300,623** | **$ 2,358,932** | **$ 58,309** |

c) The call centre was not fully staffed at the end of 2018 and is not fully staffed today. This is due to the unpredictable nature of absences that may be a result of a leave of absence, maternity leave, or those that announce their retirement.

- Currently, ENWIN has three vacancies in the call centre: one due to long term disability and two due to maternity leave. ENWIN is currently employing three temporary staff to cover these leaves.
- Understaffing is due to vacancies as a result of long term disability, maternity leave, and retirement. These unplanned vacancies create short term variances that are out of the control of ENWIN. Typically, ENWIN backfills positions as required due to those unplanned absences with temporary staff.
- In 2017, the department had three employees on maternity leave and two employees on long term disability for a total of five full time employees. In 2020, ENWIN is currently expecting to have both employees on maternity leave returning, with only one employee that could potentially still be on long term disability. In 2020, it is therefore

expected that ENWIN will have a full complement of permanent full time call centre staff.

## 4 - OEB Staff - 94

Reference:

Exhibit 4, Pages 14 and 35; Windsor Star Publication Jun 26, 2019

Preamble:

EnWin Utilities states:

For 2019 and 2020 ENWIN has projected inflationary increases of 2.25% for wages and salaries estimated as necessary given the strong economic climate in Windsor presently and local competitive forces for skilled trade positions.

EnWin Utilities further explains in employee compensation section that ENWIN has used an increase of 2.25% for the 2019 Bridge Year and 2.25% for the 2020 Test Year for wages and salaries and an increase of 2.0% for benefits, compared to 2.0% utilized for non-labour items.

OEB staff notes from the June 26, 2019 publication of the Windsor Star that **Enwin hydro** workers have ratified a new five-year collective agreement. **EnWin Utilities Ltd**. and the members of the International Brotherhood of **Electrical** Workers (IBEW) Local 636, representing the **hydro** division, said in a Tuesday news release that the workers had ratified the new deal. The agreement runs from April 1, 2019 to March 31, 2024. Unionized workers in **Enwin's** water division ratified a four-year agreement in February. The five-year deal announced Tuesday for about 60 unionized workers includes two per cent wage increases each year, plus some increases to boot and clothing allowances, benefits and shift premiums. [Emphasis Added by Staff]

Question:

a) Please update the applicable employee wage increase for 2019 and 2020 using the new rate of 2% in the new five-year collective agreement.

---

Response:

ENWIN confirms that the employee wage increase for 2019 and 2020 in the new five-year collective agreement is 2%, which is slightly below the employee wage increase of 2.25% for 2019 and 2020 used in the original forecast submission.

Below is a table showing the difference between the original forecast submission and the current collective agreement.

| | 2019 Bridge Year 2% vs 2.25% Hydro Union | 2020 Test Year 2% vs 2.25% Hydro Union |
|---|---|---|
| **Total Compensation (Wages & Benefits) variance** | (18,601) | (39,250) |

Since the amounts above are immaterial, ENWIN has not adjusted any OM&A or capital projections in the Bridge or Test Years.

## 4 - OEB Staff - 95

Reference:

Exhibit 4, Page 21

Preamble:

EnWin Utilities provides the explanation of the increase in OM&A expense of $657,301 due to the IT systems from 2009 actuals and 2010 actuals as follows:

The increase in costs were a result of the implementation of a new ERP system, specifically SAP. Costs declined in 2011 and 2012 back to the 2009 Board Approved levels once the system was fully implemented.

Question:

a) Please explain the types of costs expensed in the 2010 OM&A due to the implementation of the new ERP system SAP.

---

a) The types of costs expensed in the 2010 OM&A due to the implementation of SAP include the costs to operate and the costs to support and maintain the system.

   Cost to Operate: This is represented by the costs of the infrastructure and operations necessary to allow the application to provide the required level of performance, usability and availability. Outside consultants were used to perform the operational tasks in 2010 since ENWIN's internal staff had not yet been trained.

   Cost to Support and Maintain: These are the costs associated with paying SAP for software maintenance and paying ENWIN's implementation partner to provide application level support in the first year after go-live.

## 4 - OEB Staff - 96

Reference:

Exhibit 4, Page 22

Preamble:

EnWin Utilities explains the variance in 2019 OM&A as compared to 2018 due to the information systems of $373,144 as follows:

The variance is a result of lower than normal operating costs as a result of delays in implementing a customer portal in 2018. The Bridge Year also contains cyber security related costs.

Question:

a) Please provide the cyber security related costs that were included in the 2019 bridge year.

---

Response:

a) The cyber security related costs that were included in the 2019 bridge year are as follows:

| Cyber security related costs | 2019 |
|---|---|
| Anti Virus maintenance | $9,316 |
| Firewall maintenance | $18,632 |
| End point protection | $1,096 |
| Email Message scanning | $10,960 |
| Firewall Management | $1,644 |
| Smart Meter security audit | $35,000 |
| Security monitoring (SOC) | $137,976 |
| 2 Factor Authentication | $10,960 |
| Corporate penetration/security yearly assessment | $19,180 |
| | $244,764 |

## 4 - OEB Staff - 97

Reference:

Exhibit 4, Page 23

Preamble:

OEB staff notes that the bad debt expense fluctuates significantly over the period of 2009 to 2020.

Question:

a) Please explain EnWin Utilities' accounting policy to accrue the annual bad debt expenses. If there has been a change of the policy in the period of 2009 to 2020, please explain the change.

---

Response:

The bad debt expense is made up of two major components; i) a provision for bad debts and ii) actual bad debts that are written off.

The provision for bad debt expense is the component within the total expense that is more likely to fluctuate year over year or month over month depending on the balances that exist in accounts receivable at the end of a period.

The provision is established based on the aging of accounts receivable and the type of balance outstanding. To determine the amount of a provision, the outstanding accounts receivable at the end of a period are isolated into 'Active' and 'Final Billed'. Those balances are then aged and a factor is applied to each grouping. The provision factors were increased in 2014 based on experience and trends. The current provision factors are as follows:

| | Current – 60 days | 61 – 90 days | 91 – 365 days | >365 days |
|---|---|---|---|---|
| **Active** | 0% | 20% | 50% | 100% |
| **Inactive** | 80% | 100% | 100% | 100% |

Actual write offs of accounts receivable occur when attempts to collect are unsuccessful or if it is known that the balance will not be collected.

The bad debt expense approach has been consistent throughout the 2009 – 2020 period.

## 4 - OEB Staff - 98

Reference:

Exhibit 4, Page 24

Preamble:

EnWin Utilities, in explaining the cost driver of professional fee and consulting for the increase in 2018 forecast as compared to 2017 of $278,228, states that

The 9 year average in audit, legal and consulting is $863,258 for the periods 2009 – 2017. The 2017 year was unusually low with less legal and consulting work required compared to previous.

Question:

a) Please provide the 2018 actual professional and consulting fee and update the figure.

---

Response:

a) The 2018 actual professional and consulting fee expense was $579,138.

## 4 - OEB Staff - 99

Reference:

Exhibit 4, Page 30

Preamble:

EnWin Utilities states that

At the time of filing, the 2017 balances were the most recent OEB filed actual results. The 2018 balances were forecasted and were not used in this analysis. As a result, the variance analysis below highlights the last filed actual balances with the Test Year.

Question:

a) Please provide the program variance analysis of 2020 test year versus 2018 actual balances given the 2018 actual balances are available.

b) Please explain the material variances.

---

Response:

a) ENWIN has updated Appendix 2-JC with 2018 actual balances as requested.

b) Material variance explanations are as follows:

Bad Debt

| 2018 Actuals | 2020 Test Year | Variance |
|---|---|---|
| **$ 332,633** | **$ 659,334** | **$ 326,701** |

Although bad debt expense is not a program, it does represent a material portion of the total OM&A costs for ENWIN. The 2020 estimated bad debt is based on a 5 year average for the period 2013-2017. The 2018 Actual year was the second lowest in a 10 year period and the lower than normal results in 2018 were due to a recovery of balances previously written off. Therefore, the 2020 Test Year balance is reflective of the anticipated normal bad debt expense level. This variance is not directly within the control of ENWIN but rather a function of the general economic conditions in the region.

Overhead Operations & Maintenance

| 2018 Actuals | 2020 Test Year | Variance |
| --- | --- | --- |
| **$ 2,414,903** | **$ 2,765,018** | **$ 350,115** |

Pole inspections costs were favourable in 2018 compared to the 2020 Test Year due to the shortage of regular staff available to complete the work. In order to meet the required amount of inspections for the year, the work was conducted by Apprentices and summer students, which resulted in a lower cost. 2020 reflects the trend of actual spend from 2017, with an increase of $147k. The use of Apprentices and summer students is still anticipated in the 2020 Test Year but is anticipated to be applied against various O&M accounts not concentrated in this account as it was in 2018.

Load Dispatching (SCADA)

| 2018 Actuals | 2020 Test Year | Variance |
| --- | --- | --- |
| **$ 198,631** | **$ 482,793** | **$ 284,161** |

The SCADA Supervisor transferred to another position at the end of 2017 and due to challenges recruiting the appropriate skill set at the salary offered, ENWIN was not able to find an appropriate candidate during 2018. A cellular communication study was completed in 2018 to evaluate the various communication methods ENWIN uses for SCADA. It concluded that the main method of communication would be either WiMax or cellular and that the SCADA position was required.

Information Systems

| 2018 Actuals | 2020 Test Year | Variance |
| --- | --- | --- |
| **$ 1,385,034** | **$ 1,802,772** | **$ 417,738** |

ENWIN has budgeted $211,000 in security related costs for the 2020 Test Year, some of which is related to Cyber security, which is required by the OEB. User support systems costs increased due to the impact of MIST meters as well as potential for uptake of net metering. Costs to support and maintain software and licensing fees are also main drivers for this variance.

Administrative & Human Resource Expenses

| 2018 Actuals | 2020 Test Year | Variance |
|---|---|---|
| **$ 5,715,448** | **$ 6,545,999** | **$ 830,551** |

This program grouping represents the administrative expenses including wages and most of the benefits associated with the administrative functions within ENWIN. Vacancies and retirements resulted in lower administrative costs in 2018 compared to 2020. Those vacancies and retirements are not anticipated to persist into the future at the same rate. Also, the allowances for slow moving inventory is in this grouping and the 2018 actual balance was lower than 2020 by $202,084. That adjustment in 2018 was required because the ending 2017 balance was higher than normal. The 2020 ending balance is more reflective of the average balance.

Regulatory Affairs

| 2018 Actuals | 2020 Test Year | Variance |
|---|---|---|
| **$ 585,910** | **$ 304,374** | **$ 281,536** |

As described in the response to OEB Staff – 120 b) i) The OM&A in the 2020 Test Year is $206,218 understated. This has not yet been adjusted in the Chapter 2 Appendices or any of the other filings.

Audit, Legal and Consulting

| 2018 Actuals | 2020 Test Year | Variance |
|---|---|---|
| **$ 579,138** | **$ 896,526** | **$ 317,388** |

The 9 year average in audit, legal and consulting is $863,258 for the periods 2009 – 2017. The 2018 year was unusually low with less legal and consulting work required compared to previous periods due primarily to the focus of Cost of Service project.

## 4 - OEB Staff - 100

Reference:

Exhibit 4, Page 30; Exhibit 2, Page 27

Preamble:

EnWin Utilities explains the reasons of its 2020 general plant and vehicles expense is $322k less than 2017 general plant and vehicles as follows:

ENWIN is planning on allocating more vehicle costs to capital and O&M in 2020 compared to 2017 Actuals. ENWIN is also attempting to extend the lives of vehicles and delay maintenance on buildings whenever possible. ENWIN does have control over these costs.

EnWin Utilities states in Exhibit 2 that it decided to move from leasing the vehicles to buy the vehicles in 2018 based on a leave versus buy analysis.

Question:

a) Please provide the analysis.

b) Please explain the saving of the 2018 actual and 2019 and 2020 forecast vehicle expenses in OM&A expense from this decision.

Response:

a) Please refer to the response to OEB Staff question 14. Contained within that response are attachments which include the report to the Board of Directors which highlights the embedded financing fees paid to the leasing companies and also provides an analysis for two different types of vehicles with a Net Present Value calculation for each scenario.

b) ENWIN bought out the vehicle leases in late December 2018 therefore there are no savings realized during 2018 related to the lease buyout in that calendar year.

The chart below highlights the interest cost avoided offset by the interest income given up:

| | **2019** | **2020** |
|---|---|---|
| **Lease Interest Avoided*** | $ 89,882 | $ 66,385 |
| **Administration fees Avoided** | 4,820 | 3,450 |
| **Lease Costs Avoided** | $ 94,702 | $ 69,835 |
| | | |
| **Interest Revenue – opportunity costs given up**** | $ 44,828 | $45,815 |
| | | |
| **Net interest savings** | $ 44,874 | $ 24,020 |

*Assumes a 2.0% bankers' acceptance rate which existed at June 28, 2019 for the full 2 year period

** Assumes prime rate of 3.95% for the full 2 year period

## 4 - OEB Staff - 101

Reference:

Exhibit 4, Pages 38 and 39

Preamble:

EnWin Utilities explains it uses the administration service only for the health and dental program for its employees:

Health & Dental Benefits – ENWIN has an Administrative Services Only (ASO) plan with Green Shield Canada. The plan has specific stop loss levels to protect ENWIN against individual claims in excess of a specific limit.

EnWin Utilities provides the costs for its health and dental in figure 4-16 below:

Page 39 |

| | 2009 Board Approved | 2020 Proposed Test Year | Change 2009 Board Approved to 2020 Test Year | | |
|---|---|---|---|---|---|
| | $ | $ | $ | % | CAGR |
| OMERS | 943,897 | 1,892,628 | 948,731 | 100.5% | 6.5% |
| LTD Insurance | 138,784 | 220,458 | 81,674 | 58.8% | 4.3% |
| Life Insurance | 351,862 | 305,312 | (46,550) | -13.2% | -1.3% |
| Health and Dental Benefits | 671,304 | 672,602 | 1,298 | 0.2% | 0.0% |
| **Total Company Benefits** | **2,105,847** | **3,091,000** | **985,153** | **46.8%** | **3.6%** |

Figure 4-16: Company Benefits Costs

OEB staff notes that the health and dental costs has increased slightly from 2009 to 2020 but it is account for almost 22% ($672,602/$3,091,000) of the total company benefits in 2020.

Question:

a) Please provide the reasons that EnWin Utilities decides to use the Administrative Services Only plan instead of other options such as a fully insured plan.

b) Please provide the other options that EnWin Utilities has in terms of health and dental plan (i.e. fully insured plan).

c) Has EnWin Utilities considered the other options and performed the cost and benefit analysis?

i) If so, please provide the analysis.

ii) If not, why not.

Response:

a) The reason ENWIN utilizes an Administration Services Only ("ASO") plan instead of insured plans is because that structure is believed to be industry best practice given the size of ENWIN. ENWIN utilizes an independent third party health and benefit consultant and through consultation with that advisor and managements experience, the use of an ASO plan with stop loss limits excess claims while also helps to manage costs.

b) ENWIN has an ASO plan with stop loss.

   The other alternatives include pure ASO; fully insured and an insured/refund plans.

c) ENWIN has not conducted a formal study on the alternative funding arrangements. The use of an external industry consultant is used to leverage best practices and that advice along with active management and monitoring of the ASO plan helps to manage costs.

## 4 - OEB Staff - 102

Reference:

Exhibit 4, Pages 46 and 47

Preamble:

In explaining the year-over-year variances for wages and benefits, EnWin Utilities states that

The increase in 2010 Actual wages compared to 2009 Actual wages for Management and Non-Management of $263 thousand and $ 729 thousand was due to the general rate increase for the year together with restructuring costs for changes in staffing.

OEB staff notes that the FTE headcount for non-management decreased by 5 from 2009 to 2010.

Question:

a) Please explain why the non-management wages had increased by $729k while the FTE decreased by 5 in 2010.

b) Please provide the restructuring cost for the non-management in 2010.

---

Response:

a) In 2009 and 2010, the end of year headcount was used instead of using FTE. When examining the reason for the decrease in headcount compared to the increase in salaries year over year, the issue appears to be the way the headcount and FTE was calculated since the salaries were derived using payroll.

   ENWIN attempted to recreate the FTE calculation but was unable to for those years because ENWIN converted to a new payroll/ERP system and the legacy system data was not available.

b) As stated above, the detailed payroll information is not readily available for 2009 and 2010 due to the ERP/payroll system conversion. However, approximately $177,000 is related to restructuring costs.

## 4 - OEB Staff - 103

Reference:

Exhibit 4, Page 51

Preamble:

EnWin Utilities states that

Please refer to Attachment 4-I Study of Affiliate service Costs and Cost Allocation 2008 ("Study") performed by BDR North America Inc. ("BDR") in 2008 to review ENWIN's approaches to transfer pricing arrangements. An update to this Study was performed in 2012 and can be found in Appendix 4-J Allocation of Costs to Affiliates, Update to 2008 Study ("Study Update") to update changes since the 2008 Study. *ENWIN* continues to review and enhance where necessary its pricing methodology.

Question:

a) Please confirm whether or not EnWin Utilities has updated its cost allocation study for its affiliated service costs since 2012?

i) If not, why not.

ii) When does EnWin Utilities plan to perform another study or update?

Response:

a) ENWIN engaged BDR North America Inc. to conduct a cost allocation study related to transfer pricing to ensure compliance and adherence to the Affiliate Relationships Code for Electricity Distributors and Transmitters in 2008, and again in 2012 ("Study Update").

The ENWIN corporate cost allocation model used during those studies was consistent over the 2008 to 2012 time period. Since 2012, the same model and approach has been adopted when allocating shared service costs.

In anticipation of ENWIN's 2020 Cost of Service application, ENWIN utilized its consultant, who was engaged to assist with the application, to assess the corporate cost allocation model. ENWIN decided not to undertake a formal review of the cost allocation model in order to minimize the external consultant costs of preparing this application, which helps to reduce rates for our customers. Ultimately, it was determined that the 2012 cost allocation study still provided a reasonable basis for the allocation of costs amongst ENWIN and its affiliates.

ENWIN will continue to review the cost allocation model for appropriateness and any material changes in circumstances that may warrant updates or a new study going forward.

## 4 - OEB Staff - 104

Reference:

Exhibit 4, Attachment 4-J Allocation of Costs to Affiliates, Update to 2008 Study

Preamble:

The 2012 report provided in Attachment 4-J states that

Since that time, there have been changes in the services provided, and in the structure by which certain services are being provided. Specifically, an allocation of costs must now been made for CDM activities, the costs of which are recoverable from the Ontario Power Authority.

OEB staff notes how the allocation of costs for the CDM activities was not provide in the 2012 report.

Question:

a) Please provide the allocation methodology for the CDM activities.

---

Response:

a) The methodology used to allocate costs for CDM activities is consistent with other affiliate charges.

   Cost drivers are identified for key activities within the shared service areas and those cost drivers are used to allocate the costs within each cost centre to each of the affiliates. Those cost drivers are updated routinely to ensure the appropriate allocations are being applied.

   All shared service costs are allocated to all of the affiliates including CDM, but the most significant shared service costs that are allocated to CDM activities relate to IT, Human Resource and Finance. Specifically, IT costs are allocated using a combination of both hardware and software applications. The cost driver used for Human Resources is FTE and the cost driver used for Finance is derived based on actual effort spent on affiliate related activities. Each of these cost drivers has different allocations to each of the affiliates and those drivers are used to allocate and determine the total charges to CDM and other affiliates.

## 4 - OEB Staff - 105

Reference:

Exhibit 4, Page 54

Preamble:

EnWin Utilities provides a figure in explaining the variances as below:

| Item | 2009 Board Approved | 2017 Actual | 2020 Test Year | 2020 Test Year vs. 2009 Board Approved | 2020 Test Year vs. 2017 Actual |
|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ |
| Price for the Services Provided | 13,959,036 | 22,394,673 | 22,473,542 | 8,514,506 | 78,868 |
| Costs for the Services Provided | 12,152,294 | 21,684,366 | 21,861,824 | 9,709,530 | 177,457 |
| Net Miscellaneous Revenue | 1,806,742 | 710,307 | 611,718 | - 1,195,024 | - 98,589 |

Figure 4-26: Summary of Affiliate Services and Corporate Cost Allocations

EnWin Utilities explains the variances between 2020 test year and 2009 last rebasing year as below:

The two main factors for the increase in Price for services provided from the 2009 Board Approved amount and the 2020 Test Year are: the WSOA and inflation. The addition of direct water production, transmission, distribution, engineering and administrative services is neutral to the electrical utility but the non-utility revenue and costs filed in the USoA 4375 and 4380 accounts significantly increased as a result of the transition.

Question:

a) Please explain why the costs increased more than the prices so that the net revenues has been decreased from 2009 to 2020.

Response:

a) The net miscellaneous revenues declined in the 2020 Test Year compared to the 2009 Board Approved because of the following:

i) Return on Assets

The cost allocation model used by ENWIN allocates costs to affiliates but also charges a return on shared assets. When comparing the 2009 Board Approved return on assets compared against the 2020 Test Year return on assets the amount has declined by approximately $405,000.

The decline in net book value of the shared service assets has depreciated since 2009 and the two largest assets that have been depreciated are the Operating Center (Building) and the Customer Information System. Both of those assets have declined in net book value by approximately $7 million over the 12 year period.

ii) Working Capital

Along with a return on asset, the cost allocation model also applied a working capital charge. That working capital charge was used in cases where affiliates were benefiting from the use of ENWIN's working capital.

In 2009, the total amount charged to affiliates for working capital was approximately $148,000.

During 2017, an investigation was undertaken to see if this charge was appropriate. It was determined that ENWIN was actually using the working capital of the affiliates. ENWIN was billing and holding funds from those bills and not remitting to the affiliates immediately. Therefore, ENWIN is benefiting from those affiliate funds and, as a result, it was not appropriate to charge the affiliates for a working capital charge based on the current cash flow activities.

iii) 2009 Incremental charge

There was also a standing monthly charge to affiliates on top of the standard cost allocation model for the use of Customer Information System. In 2009, the cost allocation model charged affiliates approximately $612,000 for what was identified as a CIS charge. The source of the charge is undeterminable because the data was contained within an old ERP system and some records are no longer accessible.

The current cost allocation takes the actual costs of the CIS and other systems and allocates those charges to the affiliates. The model also charges a return on assets as well, so ENWIN is earning a return on the assets but is not earning as much as in 2009.

## 4 - OEB Staff - 106

Reference:

Exhibit 4, Pages 60 and 61; Appendix 2-BB Service Life Comparison

Preamble:

OEB staff notes that the transportation equipment has 20 years useful lives which is above the maximum (10 years) range in the Kinetrics Report.

Question:

a) Please explain the rationale of setting the transportation useful life as a much longer period of 20 years as compared to the range in Kinetrics Report.

b) Please explain whether or not EnWin Utilities has performed an analysis of the increased maintenance expenses on the old equipment vs. the purchase of new equipment. If not, why not.

---

Response:

a) This account is used for specialty equipment but more specifically includes chiller and boiler assets.

   The Kinetrics report does not have a specific category that meets the definition for this type of asset, so management's best estimate of the useful life was assumed. The use of a useful life that is greater than the Kinetrics report is more conservative and has less of a rate impact to ratepayers.

b) A certified technician is engaged annually as part of the asset condition assessment program. If the technician determines significant repairs are required a business case will be prepared to review the options including replacement, repair or any other possible alternative.

## 4 - OEB Staff - 107

Reference:

Exhibit 4, Section 4.14.1, p. 67

Tab 1-a (summary of changes) of LRAMVA workform (April 26, 2019)

Tab 5 of LRAMVA workform (April 26, 2019)

Preamble:

EnWin Utilities is applying to dispose of an LRAMVA debit balance of $2,771,982 associated with new CDM program savings between 2017 and 2018, including persisting savings from 2011 to 2016 in 2017, persisting savings from 2011 to 2017 in 2018, and carrying charges up to December 31, 2019. The LRAMVA debit balance of $2,771,982 includes both 2017 savings adjustments and unverified 2018 incremental savings results.

In Tab 1-a of the LRAMVA workform, EnWin Utilities states that it included unverified 2017 adjustments as the IESO announced on March 21, 2019 that they would not be providing LDCs with Final Verified Results Reporting for 2018-2020. For the justification of 2018 lost revenues, EnWin Utilities states in the application that it has relied on the monthly Participation and Cost reports for the 2018 implementation year.

Question:

a) Please file a copy of the 2017 Final Verified Annual CDM Program Results Report in excel format.

b) Please provide the source document for the 2017 savings adjustments included in the lost revenue calculation.

c) Please file all applicable monthly Participation and Cost reports to substantiate the 2018 unverified savings by program in Tab 5 of the LRAMVA workform. Please provide the reports in excel format.

---

Response:

a) A copy of the 2017 Final Verified Annual CDM Program Results Report (excel format) is attached. Please refer to OEB Staff 107 – Attachment 1.

b) Please refer to OEB Staff 107 – Attachment 2.

c) A copy of the March 2019 Participation and Cost Report (excel format) is attached. Please see OEB Staff 107 – Attachment 3.

The IESO has traditionally used a 15-month reporting window (January – March) to capture savings within their Final Verified Annual CDM Program Results Reporting for any given program implementation year. As such, the March 2019 Participation and Cost Report has been provided for review.

There are two differences between ENWIN's source document (See OEB Staff 107 – Attachment 2) and the IESO's March 2019 Participation & Cost Report. These differences are specific to the RETROFIT and Process & Systems Upgrade programs (2017 savings adjustments and 2018 unverified savings) and are detailed below.

RETROFIT Program

Under the RETROFIT program, there is a concept of Multi-Site Applications (MSA). MSAs are used when one customer owns/operates facilities that reside within multiple LDC service territories. Under a MSA, the LDC that is chosen as the "Head Office LDC" will manage and administer the application as if all projects were located within its service territory. All other LDCs with projects under the MSA application are termed "Satellite LDCs". Once the project(s) are complete, the Lead LDC is responsible for paying the participant incentive to the participant for all projects under the application. The costs incurred by the Lead LDC to administer the application are recovered through "MSA Fees", which are preset fees agreed upon by the IESO and LDCs, and are based on the type and size of the project(s). In these instances the IESO acts as a "clearing house", by drawing down on the Satellite LDCs CFF budget. To facilitate this draw down, each Lead LDC reports their MSA costs to the IESO on a monthly basis via their monthly settlement report (LDC Report). The IESO, then reports these costs back to each Satellite LDC via the monthly Participation & Cost Report and MSA Report. There is generally a one month delay between when these costs are reported by the Lead LDC and when they are reported back to the Satellite LDC by the IESO. Given this delay, there were 5 MSA applications that were not included within the LRAMVA work form which impacted both the 2017 savings adjustment and the 2018 unverified savings.

2017 Savings Adjustment – There were two RETROFIT MSA applications that were not included in the LRAMVA work form. These applications represent 45,064.07 kWh in net incremental energy savings, which equals the difference between ENWIN's support document and the IESO's March 2019 Participation and Cost Report. These applications are attributable to both the General Service < 50 kW rate class and the General Service > 50 kW rate class and represent

$996.45 of lost revenues in 2017 & 2018. Therefore, these applications do not have a material impact on ENWIN's LRAMVA claim. For reference, see OEB Staff 107 – Attachment 5.

2018 Unverified Savings - There were three RETROFIT MSA applications that were not included in the LRAMVA work form. These applications represent 76,770.64 kWh in net incremental energy savings, which equals the difference between ENWIN's support document and the IESO's March 2019 Participation and Cost Report. These applications are attributable to both the General Service < 50 kW rate class and the General Service > 50 kW rate class and represent $1,004.55 in lost revenues in 2018. These applications also do not have a material impact ENWIN's LRAMVA claim (see OEB Staff 107 – Attachment 5).

Process & Systems Upgrade Program

Because of IESO's decision to not provide LDCs with 2018-2020 Final Verified Annual CDM Program Results and the uncertainty around what information would be required to claim lost revenues as a direct result of CDM activities, ENWIN included two Combined Heat & Power projects within the LRAMVA work form which have yet to appear within the IESO's Participation & Cost Report. In both instances, commissioning of the CHP system is complete and the generator is running and delivering electricity savings, however these projects are still within the Measurement & Verification (M&V) phase of the project. The savings claim contained within the LRAMVA work form are supported by the IESO's Technical Reviewer M&V reports (see OEB Staff 107 – Attachment 6 and OEB Staff 107 – Attachment 7). For clarity, the savings reported back to ENWIN within the M&V reports are gross incremental savings. ENWIN then applied the net-to-gross ratios contained within the IESO's Participation & Cost Report to remain consistent. Both of these projects reside within the General Service > 50 kW rate class and contribute $101,233.67 to ENWIN's LRAMVA claim (see OEB Staff 107 – Attachment 4).

# M&V Report

## 1st Annual M&V Report

## December 28, 2017 – December 27, 2018

## [redacted] Cogeneration Project

Project ID: Enwin-SCP-600923

February 21, 2019

**Prepared for:**

EnWin Utilities Ltd. (the LDC)

[redacted] (the Participant)

**Prepared by:**

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***IPMVP defined terms:***

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

[redacted]

## Revision History

| Date | Name/Description | Revision | Author |
|---|---|---|---|
| February 21, 2019 | M&V Report issuance | 0 | [redacted], P.Eng., CMVP, CEM |

## Approvals

| Name | Title | Signature | Date |
|---|---|---|---|
| [redacted], P.Eng., CMVP, CEM | Energy Engineer | [redacted] | Feb. 25, 2019 |

[redacted]

# 1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of December 28, 2017, to December 27, 2018, are:

- 1,919 MWh, which represent 70% of the Anticipated Electricity Savings. These savings are directly related to the electricity generation of the CHP system and includes all downtimes with no adjustments.

- 2,056 MWh, which represent 75% of the Anticipated Electricity Savings, when the shutdown periods associated with equipment failures are removed from the analysis. In other words, the electricity generation is extrapolated by an amount equal to the duration of the shutdown periods.

In both scenarios, the Electricity Savings do not meet the 80% performance threshold of the Program Rules.

The Total System Efficiency is calculated as 61.4% which is below the required value of 65%.

# 2. Project Overview

## 2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Rev. 0, dated June 17, 2015, and are presented in Table 1.

This is an electricity generation Project, and therefore the Baseline Energy is 0 MWh/year.

**Table 1. Baseline Energy and Anticipated Electricity Savings**

| Description | Value | Unit |
|---|---|---|
| Baseline Energy | 0 | MWh/year |
| Anticipated Electricity Savings | 2,751 | MWh/year |

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan.

The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether or not the Project has achieved the required 80% of the Anticipated Electricity Savings.

## 2.2. In-Service Date and Previous Reporting Periods

The In-Service Date of December 28, 2017 was established on October 4, 2018.

The 1st Quarterly Reporting Period was from December 28, 2017, to March 28, 2018.

[redacted]

### 2.3. Current Reporting Period

The 1st Annual Reporting Period is from December 28, 2017, to December 27, 2018. This Reporting Period represents 365 days.

# 3. Reporting Period Energy

### 3.1. Results

[redacted] (the Participant) provided the raw data to the CMVP for analysis. The IPMVP Option B methodology is used for calculating the Electricity Savings.

The following data was provided on an hourly or 15-minute basis for the duration of the M&V Reporting Period:

- Generated electricity (power and energy during the interval);
- Natural gas consumption;
- Recovered heat of the CHP system.

Recovered thermal energy, as specified in the M&V Plan, was available but was obtained by a third party. As a reference, the Q1 thermal energy data was not available.

Table 2 presents an overview of the data analysis related to the duration of the Reporting Period, equipment hours of operation, and Reporting Period Energy.

**Table 2. Reporting Period Hours, Durations and Energy**

| Description | Value | Unit | Comments |
|---|---|---|---|
| Reporting Period Start | Dec. 28, 2017 | | Start date and time of the Reporting Period. |
| Reporting Period End | Dec. 27, 2018 | | End date and time of the Reporting Period. |
| Reporting Period Duration | 8,760 | hours | Reporting Period End minus Reporting Period Start. |
| Available Data | 8,744 | hours | 100% of the Reporting Period Duration. |
| Missing Data | 16 | hours | 0% of the Reporting Period Duration. |
| Hours of Operation | 6,418 | hours | 73% of the Reporting Period Duration. |
| **Reporting Period Energy** – no adjustment due to equipment failures | 1,919 | MWh | This is the net energy generated by the CHP System. |
| **Reporting Period Energy** – adjusted due to equipment failures | 2,056 | MWh | This is the net energy generated by the CHP System, with adjustment due to the equipment failures. |

# 4. Total System Efficiency

## 4.1. Results

The Total System Efficiency (TSE) is calculated as follows:

*TSE (%) = [CHP System Gross Energy (MWh) + Usable Thermal Output (MWh)] / [CHP Natural Gas Consumption ($m^3$) × HHV ($MWh/m^3$)]*

The TSE calculation is presented in Table 3.

**Table 3. Calculation of Overall System Efficiency**

| Description | Value | Unit | Comment |
|---|---|---|---|
| CHP System Gross Electrical Energy | 1,978 | MWh | This is the total gross electrical energy generated by the CHP System. |
| Usable Thermal Output | 1,554 | MWh | This is the total thermal energy recovered from the CHP System. |
| CHP Natural Gas Consumption | 1,401 | MWh | This is the energy content of the total fuel consumption of the CHP System, converted to units of MWh. The natural gas HHV used is 0.0388 $GJ/m^3$ as published by Union Gas for Ontario, January-June 2018. The natural gas consumption of the CHP system is 533,721 $m^3$. |
| Total System Efficiency | 61.4% | | This value is below the required value of 65%. |

## 4.2. Conclusion

The Total System Efficiency for the 1st Annual Reporting Period is 61.4%, which is below the minimum threshold of 65%.

# 5. Electricity Savings

## 5.1. Results

The Reporting Period Energy and the Electricity Savings are presented in Table 4. The Electricity Savings are calculated according to the following equation:

*Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustment*

[redacted]

**Table 4. Calculation of Electricity Savings**

| Description | Value | Unit | Comment |
|---|---|---|---|
| Baseline Energy | 0 | MWh | Obtained from Table 1. |
| Reporting Period Energy – no adjustment due to equipment failures | 1,919 | MWh | Obtained from Table 2. |
| Reporting Period Energy – adjusted due to equipment failures | 2,056 | MWh | Obtained from Table 2. |
| Non-Routine Adjustment | 0 | MWh | None. |
| **Electricity Savings** –<br>no adjustment:<br>adjusted: | **1,919**<br>**2,056** | **MWh** | This is the Reporting Period Energy minus the Baseline Energy. |
| Uncertainty of the Electricity Savings | ± 2.0% | | The Uncertainty is primarily due to the accuracy of the power meter readings and auxiliary load estimates. |
| Anticipated Electricity Savings | 2,751 | MWh | From the M&V Plan. |
| **Electricity Savings as a Percentage of Anticipated Electricity Savings** –<br>no adjustment:<br>adjusted: | **70%**<br>**75%** | | Both values do not meet the 80% performance threshold. |
| Average Demand Savings –<br>no adjustment:<br>adjusted: | 219<br>235 | kW | The Electricity Savings divided by duration of the Reporting Period. |
| Summer Peak Demand Savings | 340 | kW | Summer peak demand period is defined from June 1 to August 31, weekdays, 1pm to 7pm. |

## 5.2. Conclusion

The Electricity Savings for the 1st Annual Reporting Period are:

- 1,919 MWh, which represent 70% of the Anticipated Electricity Savings for the Reporting Period. These savings are directly related to the electricity generation of the CHP system and includes all downtimes with no adjustments.

- 2,056 MWh, which represent 75% of the Anticipated Electricity Savings, when the shutdown periods associated with equipment failures are removed from the analysis. In other words, the electricity generation is extrapolated by an amount equal to the duration of the shutdown periods. The equipment failures, which the CHP system shut down for 584 hours (24 days), are related to:

    - A faulty pressure relief valve that triggers low pressure in the cooling system which forced the CHP system to shut down.

    - A damaged propeller of the turbochargers. The fault was discovered after observing issues with the operation of the CHP system. Repairs had to be made before the CHP system could be operated normally.

[redacted]

All repairs of the above failures were made and no further issues related to these equipment were detected.

The Electricity Savings do not meet the 80% performance threshold of the Program Rules.

There were technical issues encountered during the Reporting Period that led to lower output power and fewer hours of operation than anticipated. The average output power during operation was 308 kW, which is significantly less than the 400 kW nominal rating. In addition, the CHP system operated for 73% (no adjustment) and 80% (with adjustments to exclude the shutdown due to equipment failure) of the Reporting Period, below the anticipated uptime of 95%.

## 5.3. Projected Results beyond the 1st Annual Reporting Period

It appears that most of the issues related to the operation o the CHP system were resolved by the end of October 2018. If the operation of November to December 2018 is used to assess the performance of the CHP system, the electricity savings would be at 74% of the Anticipated Electricity Savings. The CHP electrical output is usually higher in the summer, so it is likely that the electricity savings would be higher than 74%.

## 5.4. Next Reporting Period

This is the last M&V report for this Project, unless the IESO or the LDC requests additional M&V data for the reminder of the contract.

## 5.5. Electricity Savings to Date

The Electricity Savings to date are presented in Table 6.

**Table 6. Electricity Savings to Date**

| Reporting Period | Start and End Dates | Electricity Savings | | |
|---|---|---|---|---|
| | | MWh | % of Contract Savings[1] | Cost Savings[2] |
| 1st Quarterly | Dec. 28, 2017 to Mar. 28, 2018 | 419 | 72% | $64,800 |
| 1st Annual | Dec. 28, 2017 to Dec. 27, 2018 | 1,919 (no adjustment)<br>2,056 (with adjustment) | 70%<br>75% | $253,000<br>$271,000 |

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $132/MWh obtained from the Project Review.

[redacted]

# M&V Report

## 1st Quarterly M&V Report

## September 1 – November 30, 2018

## [redacted] CHP System

Project ID: Enwin-SCP-601135

December 19, 2018

**Prepared for:**

EnWin Utilities Ltd. (the LDC)

[redacted] (the Participant)

**Prepared by:**

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***IPMVP defined terms:***

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

[redacted]

## Revision History

| Date | Name/Description | Revision | Author |
|---|---|---|---|
| December 19, 2018 | First M&V Report issuance | 0 | [redacted], P.Eng., CMVP, CEM |

## Approvals

| Name | Title | Signature | Date |
|---|---|---|---|
| [redacted], P.Eng., CMVP, CEM | Engineering Manager | [redacted] | Dec 18, 2018 |

[redacted]

# 1. Executive Summary

The Electricity Savings calculated for the 1st Quarterly Reporting Period of September 1 to November 30, 2018, are 3,646 MWh, which represent 90% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold of the Program Rules.

# 2. Project Overview

## 2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Rev. 1, dated October 25, 2016, and are presented in Table 1.

This is an electricity generation Project, and therefore the Baseline Energy is 0 MWh/year.

**Table 1. Baseline Energy and Anticipated Electricity Savings**

| Description | Value | Unit |
|---|---|---|
| Baseline Energy | 0 | MWh/year |
| Anticipated Electricity Savings | 16,275 | MWh/year |

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan.

The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether or not the Project has achieved the required 80% of the Anticipated Electricity Savings.

## 2.2. In-Service Date

The In-Service Date of September 1, 2018, was established on November 21, 2018.

## 2.3. Current Reporting Period

The 1st Quarterly Reporting Period is from September 1 to November 30, 2018. This Reporting Period represents 91 days (2,184 hours).

# 3. Reporting Period Energy

## 3.1. Results

[redacted], on behalf of the Participant, provided the raw data to the CMVP for analysis. Gross electrical energy generation, auxiliary load energy, natural gas consumption for the generator and duct burners, and recovered thermal energy data was provided on an hourly basis for the duration of the M&V Period.

The IPMVP Option B methodology is used for calculating the Electricity Savings.

Table 2 presents an overview of the data analysis related to the duration of the Reporting Period, equipment hours of operation, and Reporting Period Energy.

**Table 2. Reporting Period Hours, Durations and Energy**

| Description | Value | Unit | Comments |
|---|---|---|---|
| Reporting Period Start | September 1, 2018 0:00 | | Start date and time of the Reporting Period. |
| Reporting Period End | November 30, 2018 23:59 | | End date and time of the Reporting Period. |
| Reporting Period Duration | 2,184 | hours | Reporting Period End minus Reporting Period Start. |
| Available Data | 2,183 | hours | 99.95% of the Reporting Period Duration (for gross generated power). |
| Missing Data | 1 | hours | 0.05% of the Reporting Period Duration (for gross generated power). |
| Hours of Operation | 2,004 | hours | 92% of the Reporting Period Duration. |
| Reporting Period Energy | 3,646 | MWh | Net energy generated by the CHP System. |

# 4. Electricity Savings

## 4.1. Results

The Reporting Period Energy and the Electricity Savings are presented in Table 3. The Electricity Savings are calculated according to the following equation:

*Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustments*

**Table 3. Calculation of Electricity Savings**

| Description | Value | Unit | Comment |
|---|---|---|---|
| Baseline Energy | 0 | MWh | Obtained from Table 1. |
| Reporting Period Energy | 3,646 | MWh | Obtained from Table 2. |
| Non-Routine Adjustment | 0 | MWh | None. |
| **Electricity Savings** | **3,646** | **MWh** | Reporting Period Energy minus the Baseline Energy. |
| Uncertainty of the Electricity Savings | ± 2.0% | | The Uncertainty is primarily due to the accuracy of the power meter readings. |
| Anticipated Electricity Savings | 4,058 | MWh | From the M&V Plan and prorated to the Reporting Period. |
| **Electricity Savings as a Percentage of Anticipated Electricity Savings** | **90%** | | Meets the 80% performance threshold. |
| **Total System Efficiency (TSE)** | **86%** | | For informational purposes. TSE is reported on an annual basis, and must be at least 65%. |
| Average Demand Savings | 1,819 | kW | This is Electricity Savings divided by duration of the Reporting Period. |
| Peak Demand Savings | N/A | kW | Reporting Period is outside the summer Peak Demand Period from June 1 to August 31. |

## 4.2. Conclusion

The Electricity Savings for the 1st Quarterly Reporting Period are 3,646 MWh, which represent 90% of the Anticipated Electricity Savings for the Reporting Period. The Electricity Savings meet the 80% performance threshold of the Program Rules.

The CHP system ran consistently during the Reporting Period, and actual downtime was as anticipated. The reason for the slight underperformance was lower average net generated power. This resulted from a lower than anticipated gross generated power combined with a higher than anticipated auxiliary electrical load.

The Total System Efficiency (TSE) over the Reporting Period is 86%, above the minimum threshold of 65%. Note that this is for informational purposes only, as TSE is reported on an annual basis.

## 4.3. Projected Results

The following savings projections are intended for program reporting purposes and should not be relied upon by the Participant.

The annual Electricity Savings and Peak Demand Savings projections shown in Table 4 are based on the application of Reporting Period actual data to the Project Incentive Application Review estimations. Projections are adjusted for expected operating changes for the balance of the year, such as facility shutdown schedules or seasonal effects.

Observed uptime (92%) is similar to the anticipated uptime for the quarter and the year (93% and 92%, respectively), so extrapolation of observed performance should be reasonably accurate. The projected summer peak demand savings are based on available data, since the plant operates continuously throughout the year.

**Table 4. Calculation of Projected Electricity Savings**

| Description | Value | Unit |
|---|---|---|
| Projected Reporting Period Energy | 14,623 | MWh/year |
| Projected Adjusted Baseline Energy | 0 | MWh/year |
| Projected Non-Routine Adjustment | 0 | MWh/year |
| Projected Annualized Electricity Savings | 16,275 | MWh/year |
| Projected Summer Peak Demand Savings | 1,662 | kW |
| Projected Electricity Savings as a Percentage of Anticipated Electricity Savings | 90% | |

## 4.4. Next Reporting Period

The next M&V Report (1st Annual Reporting Period) will analyze the Electricity Savings from September 1, 2018, to August 31, 2019.

## 4.5. Next Steps

The Participant will need to provide M&V data, as per the M&V Plan, for the Reporting Period of September 1, 2018, to August 31, 2019.

## 4.6. Electricity Savings to Date

The Electricity Savings to date are presented in Table 5.

**Table 5. Electricity Savings to Date**

| Reporting Period | Start and End Dates | Electricity Savings | | |
|---|---|---|---|---|
| | | MWh | % of Contract Savings[1] | Cost Savings[2] |
| 1st Quarterly | Sept. 1, 2018 – Nov. 30, 2018 | 3,646 | 90% | $481,000 |
| 1st Annual | Sept. 1, 2018 – Aug. 31, 2019 | N/A | N/A | N/A |

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $132/MWh obtained from the Project Review.

[redacted]

## 4 - OEB Staff - 108

Reference:

Tab 1-a & Tab 5 of LRAMVA workform (April 26, 2019)

Tab 5 of LRAMVA workform (2018 IRM Application, EB-2017-0037)

Preamble:

In Tab 1-a of the LRAMVA workform, EnWin Utilities notes that it overrode formulas in cells Y565 - AF571 of Tab 5 in order to ensure consistency between work form and calculations used in annual LRAMVA filings to the OEB. This suggests that EnWin program level savings (both incremental and persistent) and allocation splits have not changed from its previous LRAM filing in 2018 IRM application.

Question:

a) Please confirm that the persistence of 2015 and 2016 program savings in 2017 reflects IESO verified adjustments from the 2017 Final Verified Annual CDM Program Results Report.

b) Please show the inputs and calculations of the persistence of 2015 and 2016 program savings in 2017 in the LRAMVA workform, as they are not included in the pre-filed evidence.

---

Response:

a) ENWIN confirms that the persistence of 2015 and 2016 program savings in 2017 align with the IESO verified results adjustments from the 2017 Final Verified Annual CDM Program Results Report.

b) Please see the screen shots below detailing the persistence of the 2015 and 2016 program savings in 2017. The calculations can be found in OEB Staff 107 – Attachment 2 2011-2018 Persistence Report_ENWIN Utilities Ltd._V13_2.xlsx.

2017 Final Verified Annual CDM Program Results Report

**Savings Persistence Report**
For: EnWin Utilities Ltd.

| # | Program / Initiative Name | Net Verified Annual Energy Savings (kWh) 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| | **2015 Verified 2015 Results** | | | | |
| 67 | Appliance Retirement Initiative | 27,073 | 27,073 | 27,073 | 27,073 |
| 68 | Coupon Initiative | 779,806 | 772,732 | 772,732 | 772,732 |
| 69 | Bi-Annual Retailer Event Initiative | 1,434,212 | 1,408,722 | 1,408,722 | 1,408,722 |
| 70 | HVAC Incentives Initiative | 804,478 | 804,478 | 804,478 | 804,478 |
| 71 | Residential New Construction and Major Renovation Initiative | 7,789 | 7,789 | 7,789 | 7,789 |
| 72 | Energy Audit Initiative | 71,357 | 71,357 | 71,357 | 71,357 |
| 73 | Efficiency: Equipment Replacement Incentive Initiative | 9,956,393 | 9,956,393 | 9,892,940 | 9,892,940 |
| 74 | Direct Install Lighting and Water Heating Initiative | 1,765 | 1,765 | 447 | 447 |
| 77 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | 1,654,892 | 1,654,892 | 1,654,892 | 1,654,892 |
| 78 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | 699,957 | 580,257 | 162,019 | 162,019 |
| 80 | Low Income Initiative | 133,108 | 112,008 | 108,372 | 105,841 |
| | **Subtotal: 2015 Verified 2015 Results** | **15,570,830** | **15,397,466** | **14,910,821** | **14,908,290** |
| | **2016 Verified 2015 Results Adjustments** | | | | |
| 89 | Save on Energy Retrofit Program | 166,288 | 166,288 | 166,288 | 166,288 |
| 150 | Coupon Initiative | 131,213 | 129,341 | 129,341 | 129,341 |
| 151 | Bi-Annual Retailer Event Initiative | 14,835 | 14,661 | 14,661 | 14,661 |
| 152 | HVAC Incentives Initiative | 30,489 | 30,489 | 30,489 | 30,489 |
| 153 | Residential New Construction and Major Renovation Initiative | 3,038 | 3,038 | 3,038 | 3,038 |
| 154 | Energy Audit Initiative | 80,960 | 80,960 | 80,960 | 80,960 |
| 155 | Efficiency: Equipment Replacement Incentive Initiative | 2,064,736 | 2,064,736 | 2,064,736 | 2,064,736 |
| 162 | Low Income Initiative | 144,246 | 121,984 | 118,349 | 114,715 |
| | **Subtotal: 2016 Verified 2015 Results Adjustments** | **2,635,805** | **2,611,497** | **2,607,862** | **2,604,228** |
| | **2017 Verified 2015 Results Adjustments** | | | | |
| 171 | Save on Energy Retrofit Program | - | - | - | - |
| 237 | Efficiency: Equipment Replacement Incentive Initiative | 1,500,157 | 1,500,157 | 1,563,610 | 1,566,220 |
| 238 | Direct Install Lighting and Water Heating Initiative | -839 | -839 | 479 | 479 |
| | **Subtotal: 2017 Verified 2015 Results Adjustments** | **1,499,318** | **1,499,318** | **1,564,089** | **1,566,699** |
| | **2016 Verified 2016 Results** | | | | |
| 247 | Save on Energy Coupon Program | - | 6,293,912 | 6,293,912 | 6,293,912 |
| 252 | Save on Energy Audit Funding Program | - | 262,853 | 262,853 | 262,853 |
| 253 | Save on Energy Retrofit Program | - | 20,058,869 | 19,885,834 | 19,885,834 |
| 259 | Save on Energy Energy Manager Program | - | 1,122,503 | 1,122,503 | 1,122,503 |
| 291 | Retrocomissioning LDC Innovation Fund Pilot Program | - | 1,878,207 | 1,840,083 | 1,840,083 |
| 307 | Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program | - | 827 | 827 | 827 |
| | **Subtotal: 2016 Verified 2016 Results** | **-** | **29,617,171** | **29,406,012** | **29,406,012** |
| | **2017 Verified 2016 Results Adjustments** | | | | |
| 329 | Save on Energy Coupon Program | - | 702,824 | 702,824 | 702,824 |
| 334 | Save on Energy Audit Funding Program | - | 13,143 | 13,143 | 13,143 |
| 335 | Save on Energy Retrofit Program | - | 4,428,984 | 4,602,020 | 4,734,671 |
| 341 | Save on Energy Energy Manager Program | - | 1,671 | 1,671 | 1,671 |
| 372 | Residential Ductless Heat Pump LDC Innovation Fund Pilot Program | - | 157,963 | 157,963 | 157,963 |
| | **Subtotal: 2017 Verified 2016 Results Adjustments** | **-** | **5,304,585** | **5,477,621** | **5,610,272** |

2011-2018 Persistence Report_ENWIN Utilities Ltd._V13_2

2015 Tab (2015 Verified Savings):

## 2015 Verified Savings

For: EnWin Utilities Ltd.

| | 2015 | Program | Implementation Year | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| | | **Legacy Framework** | | | | |
| 1_2015 | 1 | Coupon Initiative | 2015 | 779,806 | 772,732 | 772,732 |
| 2_2015 | 2 | Bi-Annual Retailer Event Initiative | 2015 | 1,434,212 | 1,408,722 | 1,408,722 |
| 3_2015 | 3 | Appliance Retirement Initiative | 2015 | 27,073 | 27,073 | 27,073 |
| 4_2015 | 4 | HVAC Incentives Initiative | 2015 | 804,478 | 804,478 | 804,478 |
| 5_2015 | 5 | Residential New Construction and Major Renovation Initiative | 2015 | 7,789 | 7,789 | 7,789 |
| 6_2015 | 6 | Energy Audit Initiative | 2015 | 71,357 | 71,357 | 71,357 |
| 7_2015 | 7 | Efficiency: Equipment Replacement Incentive Initiative | 2015 | 9,956,393 | 9,956,393 | 9,892,940 |
| 8_2015 | 8 | Direct Install Lighting and Water Heating Initiative | 2015 | 1,765 | 1,765 | 447 |
| 9_2015 | 9 | New Construction and Major Renovation Initiative | | 0 | 0 | 0 |
| 10_2015 | 10 | Existing Building Commissioning Incentive Initiative | | 0 | 0 | 0 |
| 11_2015 | 11 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | 2015 | 1,654,892 | 1,654,892 | 1,654,892 |
| 13_2015 | 12 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | 2015 | 699,957 | 580,257 | 162,019 |
| 12_2015 | 13 | Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative | | 0 | 0 | 0 |
| 14_2015 | 14 | Low Income Initiative | 2015 | 133,108 | 112,008 | 108,372 |
| | 15 | Loblaws Pilot | | 0 | 0 | 0 |
| | 16 | Social Benchmarking Pilot | | 0 | 0 | 0 |
| | 17 | Conservation Fund Pilot - SEG | | 0 | 0 | 0 |
| | 18 | Conservation Fund Pilot - EnerNOC | | 0 | 0 | 0 |
| | 19 | Aboriginal Conservation Program | | 0 | 0 | 0 |
| | 20 | Program Enabled Savings | | 0 | 0 | 0 |
| | | **Conservation First Framework** | | | | |
| | 21 | Save on Energy Coupon Program | | 0 | 0 | 0 |
| | 22 | Save on Energy Heating and Cooling Program | | 0 | 0 | 0 |
| | 23 | Save on Energy Home Assistance Program | | 0 | 0 | 0 |
| | 24 | Save on Energy Audit Funding Program | | 0 | 0 | 0 |
| | 25 | Save on Energy Retrofit Program | | 0 | 0 | 0 |
| | **Total** | | | **15,570,830** | **15,397,466** | **14,910,821** |

2016 Tab (2015 Adjustments):

## 2016 Verified Savings

For: EnWin Utilities Ltd.

| | 2016 | Program | Implementation Year | 2015 | 2016 | 2017 | 2018 | 2019 | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Legacy Framework** | | | | | | | |
| a_2015 | 1 | Coupon Initiative | 2015 | 131,213 | 129,341 | 129,341 | 129,341 | 129,341 | |
| b_2015 | 2 | Bi-Annual Retailer Event Initiative | 2015 | 14,835 | 14,661 | 14,661 | 14,661 | 14,661 | |
| | 3 | Appliance Retirement Initiative | | 0 | 0 | 0 | 0 | 0 | |
| c_2015 | 4 | HVAC Incentives Initiative | 2015 | 30,489 | 30,489 | 30,489 | 30,489 | 30,489 | |
| d_2015 | 5 | Residential New Construction and Major Renovation Initiative | 2015 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | |
| e_2015 | 6 | Energy Audit Initiative | 2015 | 80,960 | 80,960 | 80,960 | 80,960 | 152,318 | |
| f_2015 | 7 | Efficiency: Equipment Replacement Incentive Initiative | 2015 | 2,064,736 | 2,064,736 | 2,064,736 | 2,064,736 | 2,064,736 | 2 |
| | 8 | Direct Install Lighting and Water Heating Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 9 | New Construction and Major Renovation Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 10 | Existing Building Commissioning Incentive Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 11 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 12 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 13 | Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative | | 0 | 0 | 0 | 0 | 0 | |
| g_2015 | 14 | Low Income Initiative | 2015 | 144,246 | 121,984 | 118,349 | 114,715 | 114,508 | |
| | 15 | Loblaws Pilot | | 0 | 0 | 0 | 0 | 0 | |
| | 16 | Social Benchmarking Pliot | | 0 | 0 | 0 | 0 | 0 | |
| | 17 | Conservation Fund Pilot - SEG | | 0 | 0 | 0 | 0 | 0 | |
| | 18 | Conservation Fund Pilot - EnerNOC | | 0 | 0 | 0 | 0 | 0 | |
| | 19 | Aboriginal Conservation Program | | 0 | 0 | 0 | 0 | 0 | |
| | 20 | Program Enabled Savings | | 0 | 0 | 0 | 0 | 0 | |
| | | **Conservation First Framework** | | | | | | | |
| 38_2016 | 21 | Building Optimization Pilot Program | 2016 | 0 | 1,878,207 | 1,840,083 | 1,840,083 | 1,799,960 | 1 |
| 51_2016 | 22 | Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program | 2016 | 0 | 827 | 827 | 827 | 827 | |
| | 23 | EnWin Heat Pump Pilot Program | | 0 | 0 | 0 | 0 | 0 | |
| | 24 | Intelligent Air Technology Pilot Program | | 0 | 0 | 0 | 0 | 0 | |
| 24_2016 | 25 | Save on Energy Home Assistance Program | | 0 | 0 | 0 | 0 | 0 | |
| 30_2016 | 26 | Save on Energy Process & Systems Upgrade Program | | 0 | 0 | 0 | 0 | 0 | |
| 25_2016 | 27 | Save on Energy Audit Funding Program | 2016 | 0 | 262,853 | 262,853 | 262,853 | 262,853 | |
| 21_2016 | 28 | Save on Energy Coupon Program | 2016 | 0 | 6,293,912 | 6,293,912 | 6,293,912 | 6,293,912 | 6 |
| 32_2016 | 29 | Save on Energy Energy Manager Program | 2016 | 0 | 1,122,503 | 1,122,503 | 1,122,503 | 1,122,503 | 1 |
| 26_2016 | 30 | Save on Energy Retrofit Program | 2016 | 0 | 20,012,797 | 19,839,762 | 19,839,762 | 19,839,762 | 19 |
| h_2015 | 31 | Save on Energy Retrofit Program | 2015 | 166,288 | 166,288 | 166,288 | 166,288 | 166,288 | |
| 33_2016 | 32 | Save on Energy Retrofit Program Enabled Savings | 2016 | 0 | 46,072 | 46,072 | 46,072 | 46,072 | |
| | **Total** | | | **2,635,806** | **32,228,669** | **32,013,875** | **32,010,240** | **32,041,267** | **32,** |

**PLUS ADJUSTMENTS FOR:**

2012 2013 2014 2015 **2016** 2017 2018 Persistence Distribution Rates Interest Summary LRAM Summary Notes Table

Average: 325,983 Count: 8 Sum: 2,607,864

2017 Tab (2015 Adjustments):

## 2017 Verified Savings

For: EnWin Utilities Ltd.

| | 2017 | Program | Implementation Year | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | **Legacy Framework** | | | | | |
| | 1 | Coupon Initiative | | | | | |
| | 2 | Bi-Annual Retailer Event Initiative | | | | | |
| | 3 | Appliance Retirement Initiative | | | | | |
| | 4 | HVAC Incentives Initiative | | | | | |
| | 5 | Residential New Construction and Major Renovation Initiative | | | | | |
| | 6 | Energy Audit Initiative | | | | | |
| a_2015 | 7 | Efficiency: Equipment Replacement Incentive Initiative | 2015 | 1,576,356 | 1,576,356 | 1,576,356 | 1,576,408 |
| b_2015 | 8 | Direct Install Lighting and Water Heating Initiative - Blended Baseline Impacts | 2015 | -839 | -839 | 479 | 479 |
| c_2015 | 9 | Efficiency: Equipment Replacement Incentive Initiative - Blended Baseline Impacts | 2015 | 27,573 | 27,573 | 91,026 | 93,290 |
| d_2015 | 10 | Efficiency: Equipment Replacement Incentive Initiative - Blended Baseline Impacts - TRUE-UP | 2015 | -103,772 | -103,772 | -103,772 | -103,478 |
| | 11 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | | | | | |
| | 12 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | | | | | |
| | 13 | Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative | | | | | |
| | 14 | Low Income Initiative | | | | | |
| | 15 | Loblaws Pilot | | | | | |
| | 16 | Social Benchmarking Pilot | | | | | |
| | 17 | Conservation Fund Pilot - SEG | | | | | |
| | 18 | Conservation Fund Pilot - EnerNOC | | | | | |
| | 19 | Aboriginal Conservation Program | | | | | |
| | 20 | Program Enabled Savings | | | | | |
| | | **Conservation First Framework** | | | | | |
| 36_2017 | 21 | Whole Home Pilot Program | 2017 | 0 | 0 | 259,670 | 259,670 |
| 23_2017 | 22 | Save on Energy Instant Discount Program | 2017 | 0 | 0 | 6,601,721 | 4,780,890 |
| a_2016 | 23 | EnWin Heat Pump Pilot Program | 2016 | 0 | 157,963 | 157,963 | 157,963 |
| | 24 | Intelligent Air Technology Pilot Program | | | | | |
| 24_2017 | 25 | Save on Energy Home Assistance Program | 2017 | 0 | 0 | 47,065 | 47,065 |
| 30_2017 | 26 | Save on Energy Process & Systems Upgrade Program | 2017 | 0 | 0 | 5,008,156 | 5,008,156 |
| b_2016 | 27 | Save on Energy Audit Funding Program | 2016 | 0 | 13,143 | 13,143 | 13,143 |
| 21_2017 | 28 | Save on Energy Coupon Program | 2017 | 0 | 0 | 7,005,969 | 5,638,884 |
| 32_2017 | 29 | Save on Energy Energy Manager Program | 2017 | 0 | 0 | 356,751 | 356,751 |
| 26_2017 | 30 | Save on Energy Retrofit Program | 2017 | 0 | 0 | 9,289,919 | 9,760,154 |
| 27_2017 | 31 | Save on Energy Small Business Lighting Program | 2017 | 0 | 0 | 310,320 | 310,320 |
| c_2016 | 32 | Save on Energy Coupon Program | 2016 | 0 | 702,824 | 702,824 | 702,824 |
| d_2016 | 33 | Save on Energy Energy Manager Program | 2016 | 0 | 1,671 | 1,671 | 1,671 |
| e_2016 | 34 | Save on Energy Retrofit Program | 2016 | 0 | 4,697,965 | 4,697,965 | 4,700,809 |
| f_2016 | 35 | Save on Energy Retrofit Program - Blended Baseline Impacts | 2016 | 0 | -268,981 | -95,945 | 33,862 |
| e_2015 | 36 | Save on Energy Retrofit Program - Blended Baseline Impacts - TRUE-UP | 2015 | 0 | 0 | 0 | 0 |

2012 2013 2014 2015 2016 2017 2018 Persistence Distribution Rates Interest Summary LRAM Summary Notes Table

Average: 312,818 Count: 5 Sum: 1,564,089

2016 Tab (2016 Verified Savings):

## 2016 Verified Savings

For: EnWin Utilities Ltd.

| | 2016 | Program | Implementation Year | 2015 | 2016 | 2017 | 2018 | 2019 | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Legacy Framework** | | | | | | | |
| a_2015 | 1 | Coupon Initiative | 2015 | 131,213 | 129,341 | 129,341 | 129,341 | 129,341 | |
| b_2015 | 2 | Bi-Annual Retailer Event Initiative | 2015 | 14,835 | 14,661 | 14,661 | 14,661 | 14,661 | |
| | 3 | Appliance Retirement Initiative | | 0 | 0 | 0 | 0 | 0 | |
| c_2015 | 4 | HVAC Incentives Initiative | 2015 | 30,489 | 30,489 | 30,489 | 30,489 | 30,489 | |
| d_2015 | 5 | Residential New Construction and Major Renovation Initiative | 2015 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | |
| e_2015 | 6 | Energy Audit Initiative | 2015 | 80,960 | 80,960 | 80,960 | 80,960 | 152,318 | |
| f_2015 | 7 | Efficiency: Equipment Replacement Incentive Initiative | 2015 | 2,064,736 | 2,064,736 | 2,064,736 | 2,064,736 | 2,064,736 | 2 |
| | 8 | Direct Install Lighting and Water Heating Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 9 | New Construction and Major Renovation Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 10 | Existing Building Commissioning Incentive Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 11 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 12 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | | 0 | 0 | 0 | 0 | 0 | |
| | 13 | Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative | | 0 | 0 | 0 | 0 | 0 | |
| g_2015 | 14 | Low Income Initiative | 2015 | 144,246 | 121,984 | 118,349 | 114,715 | 114,508 | |
| | 15 | Loblaws Pilot | | 0 | 0 | 0 | 0 | 0 | |
| | 16 | Social Benchmarking Pilot | | 0 | 0 | 0 | 0 | 0 | |
| | 17 | Conservation Fund Pilot - SEG | | 0 | 0 | 0 | 0 | 0 | |
| | 18 | Conservation Fund Pilot - EnerNOC | | 0 | 0 | 0 | 0 | 0 | |
| | 19 | Aboriginal Conservation Program | | 0 | 0 | 0 | 0 | 0 | |
| | 20 | Program Enabled Savings | | 0 | 0 | 0 | 0 | 0 | |
| | | **Conservation First Framework** | | | | | | | |
| 38_2016 | 21 | Building Optimization Pilot Program | 2016 | 0 | 1,878,207 | 1,840,083 | 1,840,083 | 1,799,960 | 1 |
| 51_2016 | 22 | Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program | 2016 | 0 | 827 | 827 | 827 | 827 | |
| | 23 | EnWin Heat Pump Pilot Program | | 0 | 0 | 0 | 0 | 0 | |
| | 24 | Intelligent Air Technology Pilot Program | | 0 | 0 | 0 | 0 | 0 | |
| 24_2016 | 25 | Save on Energy Home Assistance Program | | 0 | 0 | 0 | 0 | 0 | |
| 30_2016 | 26 | Save on Energy Process & Systems Upgrade Program | | 0 | 0 | 0 | 0 | 0 | |
| 25_2016 | 27 | Save on Energy Audit Funding Program | 2016 | 0 | 262,853 | 262,853 | 262,853 | 262,853 | |
| 21_2016 | 28 | Save on Energy Coupon Program | 2016 | 0 | 6,293,912 | 6,293,912 | 6,293,912 | 6,293,912 | 6 |
| 32_2016 | 29 | Save on Energy Energy Manager Program | 2016 | 0 | 1,122,503 | 1,122,503 | 1,122,503 | 1,122,503 | 1 |
| 26_2016 | 30 | Save on Energy Retrofit Program | 2016 | 0 | 20,012,797 | 19,839,762 | 19,839,762 | 19,839,762 | 19 |
| h_2015 | 31 | Save on Energy Retrofit Program | 2015 | 166,288 | 166,288 | 166,288 | 166,288 | 166,288 | |
| 33_2016 | 32 | Save on Energy Retrofit Program Enabled Savings | 2016 | 0 | 46,072 | 46,072 | 46,072 | 46,072 | |
| | **Total** | | | **2,635,806** | **32,228,669** | **32,013,875** | **32,010,240** | **32,041,267** | **32,** |

**PLUS ADJUSTMENTS FOR:**

2012 | 2013 | 2014 | 2015 | **2016** | 2017 | 2018 | Persistence | Distribution Rates | Interest Summary | LRAM Summary | Notes | Table

dy    Average: 4,200,859    Count: 7    Sum: 29,406,011

2017 Tab (2016 Adjustments):

## 2017 Verified Savings

For: EnWin Utilities Ltd.

| | 2017 | Program | Implementation Year | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | **Legacy Framework** | | | | | |
| | 1 | Coupon Initiative | | | | | |
| | 2 | Bi-Annual Retailer Event Initiative | | | | | |
| | 3 | Appliance Retirement Initiative | | | | | |
| | 4 | HVAC Incentives Initiative | | | | | |
| | 5 | Residential New Construction and Major Renovation Initiative | | | | | |
| | 6 | Energy Audit Initiative | | | | | |
| a_2015 | 7 | Efficiency: Equipment Replacement Incentive Initiative | 2015 | 1,576,356 | 1,576,356 | 1,576,356 | 1,576,408 |
| b_2015 | 8 | Direct Install Lighting and Water Heating Initiative - Blended Baseline Impacts | 2015 | -839 | -839 | 479 | 479 |
| c_2015 | 9 | Efficiency: Equipment Replacement Incentive Initiative - Blended Baseline Impacts | 2015 | 27,573 | 27,573 | 91,026 | 93,290 |
| d_2015 | 10 | Efficiency: Equipment Replacement Incentive Initiative - Blended Baseline Impacts - TRUE-UP | 2015 | -103,772 | -103,772 | -103,772 | -103,478 |
| | 11 | Process and Systems Upgrades Initiatives - Project Incentive Initiative | | | | | |
| | 12 | Process and Systems Upgrades Initiatives - Energy Manager Initiative | | | | | |
| | 13 | Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative | | | | | |
| | 14 | Low Income Initiative | | | | | |
| | 15 | Loblaws Pilot | | | | | |
| | 16 | Social Benchmarking Pilot | | | | | |
| | 17 | Conservation Fund Pilot - SEG | | | | | |
| | 18 | Conservation Fund Pilot - EnerNOC | | | | | |
| | 19 | Aboriginal Conservation Program | | | | | |
| | 20 | Program Enabled Savings | | | | | |
| | | **Conservation First Framework** | | | | | |
| 36_2017 | 21 | Whole Home Pilot Program | 2017 | 0 | 0 | 259,670 | 259,670 |
| 23_2017 | 22 | Save on Energy Instant Discount Program | 2017 | 0 | 0 | 6,601,721 | 4,780,890 |
| a_2016 | 23 | EnWin Heat Pump Pilot Program | 2016 | 0 | 157,963 | 157,963 | 157,963 |
| | 24 | Intelligent Air Technology Pilot Program | | | | | |
| 24_2017 | 25 | Save on Energy Home Assistance Program | 2017 | 0 | 0 | 47,065 | 47,065 |
| 30_2017 | 26 | Save on Energy Process & Systems Upgrade Program | 2017 | 0 | 0 | 5,008,156 | 5,008,156 |
| b_2016 | 27 | Save on Energy Audit Funding Program | 2016 | 0 | 13,143 | 13,143 | 13,143 |
| 21_2017 | 28 | Save on Energy Coupon Program | 2017 | 0 | 0 | 7,005,969 | 5,638,884 |
| 32_2017 | 29 | Save on Energy Energy Manager Program | 2017 | 0 | 0 | 356,751 | 356,751 |
| 26_2017 | 30 | Save on Energy Retrofit Program | 2017 | 0 | 0 | 9,289,919 | 9,760,154 |
| 27_2017 | 31 | Save on Energy Small Business Lighting Program | 2017 | 0 | 0 | 310,320 | 310,320 |
| c_2016 | 32 | Save on Energy Coupon Program | 2016 | 0 | 702,824 | 702,824 | 702,824 |
| d_2016 | 33 | Save on Energy Energy Manager Program | 2016 | 0 | 1,671 | 1,671 | 1,671 |
| e_2016 | 34 | Save on Energy Retrofit Program | 2016 | 0 | 4,697,965 | 4,697,965 | 4,700,809 |
| f_2016 | 35 | Save on Energy Retrofit Program - Blended Baseline Impacts | 2016 | 0 | -268,981 | -95,945 | 33,862 |
| e_2015 | 36 | Save on Energy Retrofit Program - Blended Baseline Impacts - TRUE-UP | 2015 | 0 | 0 | 0 | 0 |

2012 2013 2014 2015 2016 2017 2018 Persistence Distribution Rates Interest Summary LRAM Summary Notes Tabl

Average: 912,937 Count: 6 Sum: 5,477,620

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Reference:

Tab 1-a & Tab 6 of LRAMVA workform (April 26, 2019)

Preamble:

In Tab 1-a of the LRAMVA workform, EnWin Utilities notes the formulas in Table 6-a (2017 and Q1 2018 carrying charges) were overridden to allow *ENWIN* Utilities to pull LRAMVA amounts previously claimed to calculate carrying charges prior to disposition (May 1, 2018 - EB-2017-0037).

Question:

a) Please explain in greater detail the rationale for not calculating carrying charges for 2017 and Q1 2018 based on the LRAMVA balance.

Response:

a) ENWIN calculated carrying charges for 2017 based on the LRAMVA balance that resulted from 2017 CDM programs and savings persisting in 2017 from the 2011-2016 program years. Similarly, ENWIN calculated the carrying charges for Q1 2018 on the LRAMVA balance that resulted from 2018 CDM programs and savings persisting in 2018 from the 2011-2017 program years.

ENWIN calculated the carrying charges in this manner as it received approval to dispose of the LRAMVA balance (2011-2016 program years) as of May 1, 2018. The carrying charges for Q2 2018 and all proceeding periods were calculated based on the LRAMVA balance that resulted from 2018 CDM programs and the savings persisting in 2018 from the 2017 program year.

## 4 - OEB Staff - 110

Reference:

Tab 1 of the LRAMVA workform

Exhibit 9, Section 9.6.3, p. 26 of 37

2020 DVA Model, Tab 7 (Rate Rider Calculations)

Preamble:

In Exhibit 9, EnWin Utilities shows the breakdown of the LRAMVA balances by rate class. EnWin Utilities states that the residential LRAM amounts are proposed to be recovered through a monthly fixed charge. It appears that disposition of the residential LRAM is recovered through a volumetric charge, as shown in the DVA Model.

Question:

a) Please confirm whether EnWin Utilities seeks to dispose of the residential LRAM through a fixed customer charge. If yes, please make the necessary revisions to Tab 7 of the DVA Model.

---

Response:

a) ENWIN calculated the residential rate rider for account 1568 using kWh pursuant to Section 2.8.2, Rate Design Policy of the Chapter 2 filing requirements, which states:

> "In proposing a transition to a fully fixed monthly service charge, the distributor must follow the approach set out in Tab 12 of the RRWF. Generally speaking, distributors must propose a fully fixed rate design for charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity.
>
> Pass-through costs (e.g. transmission rates, low-voltage service rates, and Group 1 DVAs) and LRAMVA amounts **are to continue to be recovered as variable charges because they predominantly relate to energy charges**." [emphasis added]

ENWIN agrees that the first sentence of Section 9.6.3 Proposed Rate Riders, sub-section 1568 – LRAM Rate Rider of the Application should read "Consistent with the Filing Requirements, ENWIN has calculated the Residential rate rider as a volumetric charge".

## 4 - OEB Staff - 111

Reference:

Tab 1 & Tab 1-a of LRAMVA workform (April 26, 2019)

Question:

a) Please update the formula in row 85 of Table 1-b (Tab 1) to include the 2018 LRAMVA balance in Table 1-b of the LRAMVA workform.

b) Please file an updated LRAMVA work form as a result of its responses to the above LRAMVA interrogatories.

c) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

Response:

a) Table 1-b in the LRAMVA work form has been updated to include the 2018 LRAMVA balance.

b) A revised copy of the LRAMVA work form is attached. Please refer to OEB Staff 111 – Attachment 1.

c) All changes as a result of the LRAMVA interrogatories have been included in Table A-2.

## 4 - OEB Staff - 112

Reference:

Exhibit 4 – Section 4.13, PILs

Question:

a) Please provide a copy of the 2018 Income Tax Return

b) Please provide an updated PILs model (using the updated 2020 OEB PILs model – attached as Appendix 2) for the historical, bridge and test years to align with EnWin Utilities' closing 2018 tax continuity schedules as appropriate (Schedule 4, Schedule 8, Schedule 13) and update any other areas of the application that include the 200 PILs forecast.

---

Response:

a) ENWIN's 2018 Tax Return is attached. Please note that personal information has been redacted as per filing requirements.

b) The 2020 PILS model has been updated which includes the 2018 actuals along with all corresponding schedules.

KPMG LLP
618 Greenwood Centre
3200 Deziel Drive
Windsor ON N8W 5K8
Tel 519-251-3500
Fax 519-251-3530
www.kpmg.ca

**Private and Confidential**

Helga Reidel
CEO
Enwin Utilities Ltd.
787 Ouellette Avenue
PO Box 1625, Station A
Windsor, ON N9A 5T7

June 18, 20199

Dear Mrs. Reidel:

**CORPORATE INCOME TAX RETURNS**

We have prepared and enclose the Payments in Lieu of Federal and Provincial Corporate Tax (Hydro PILs) (the "Returns") of Enwin Utilities Ltd. (the “Company”) for the period ended December 31, 2018 and the related Corporate Income Tax Filing Instructions (the "Filing Instructions").

We have prepared these Returns based on our understanding of and reliance upon the facts, data, materials, assumptions and other information (collectively, the “Information”) provided to us by the Company and/or its representatives, and we have not independently investigated or verified the accuracy or completeness of such Information. We accept no responsibility or liability for any errors attributable to our reliance upon inaccurate or incomplete Information. We recommend that you carefully review the Returns in their entirety to ensure that all of the relevant Information is correctly and completely disclosed.

Please review the enclosed Filing Instructions. When you are satisfied that the Returns are in order they must be filed (electronically or in paper format) with the respective taxing authorities by the due date (as set out in the Filing Instructions) if late filing penalties are to be avoided or minimized, or if losses are carried back to a prior taxation year.

**KEY TAX ATTRIBUTES SUMMARY**

We are pleased to provide you with select key tax information on the *Corporate Tax Return - Key Tax Attributes Summary*. This document lists key amounts and carryforward balances from the Returns and may assist in identifying future potential tax planning opportunities.

**SUMMARY OF SCIENTIFIC RESEARCH & EXPERIMENTAL DEVELOPMENT ("SR&ED") CLAIM**

We have prepared the SR&ED claim based on our understanding of the information provided to us by the Company and we recommend that you review the claim to ensure that all of the relevant facts are properly disclosed.

The nature of our service is to assist the Company in filing claims for SR&ED investment tax credits. We cannot guarantee CRA will accept the Company's research and development activities as qualifying SR&ED activities or that CRA will approve all the Company's research and development expenditures as qualifying SR&ED expenditures. However, the SR&ED claim was prepared based on our professional judgment that the identified activities constitute qualifying SR&ED and all of the appropriate expenditures relating to those activities have been identified. Much of the success of the submission will depend on the integrity and validity of the data collected.

To mitigate the risk of penalties, Part 9 (Claim preparer information) of Form T661 *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* must be fully completed (except where the Company has chosen to separately file under CRA's administrative measure). If any of the prescribed claim preparer information is missing, incomplete, or inaccurate, a penalty of $1,000 may be assessed and the processing of your SR&ED claim may be delayed.

**CRS AND FATCA REPORTING REQUIREMENTS**

Certain Canadian entities are required to report to the Canada Revenue Agency annually on any account holders determined to be Specified US persons under *Part XVIII - Enhanced International Information Reporting* of the Canadian *Income Tax Act* (the Canadian implementation of the US *Foreign Account Tax Compliance Act*, commonly referred to as "FATCA").

Certain Canadian entities are also required to report to the Canada Revenue Agency annually on any account holders determined to be tax residents of countries other than Canada or the United States under *Part XIX - Common Reporting Standard* of the Canadian *Income Tax Act* (commonly referred to as the "CRS").

Please contact us if you have any questions about responding to a request from a financial institution to certify your FATCA or CRS status, or determining whether you are subject to the due diligence and reporting requirements under the CRS or FATCA.

**PROPOSED TAX CHANGES**

The Company's tax return(s) have been prepared taking into account certain proposals to amend the federal and provincial tax statutes which have been publicly announced to date in budgets and other government releases as being applicable to the Company's current taxation year, even though the proposals may not yet be enacted. If the proposed amendments are not enacted as announced, these tax returns could be reassessed and may result in an underpayment of tax, and possible interest and penalties. If you receive an assessment or reassessment for these tax returns that does not agree with the returns filed, it is important that you notify us so that we can determine if any action needs to be taken.

**INSTALMENTS**

We have prepared and enclose an estimate of tax instalments as applicable for the Company for the taxation year ending on December 31, 2019. These include instalments for federal income tax and for provincial income and capital taxes. The amounts were computed with reference to the Company's taxable income, taxable capital and income taxes payable for prior years. If during the year it is evident that the taxable income or taxable capital for the current year will be substantially less than for the previous taxation year, the Company may wish to reduce its cash tax payments by recalculating its instalment payments. Overpaid instalments may, in certain circumstances, be transferred to other accounts or applied to other liabilities such as payroll withholdings. If either of these cases apply, please call your KPMG advisor in order that we may assist you in determining what course of action should be taken.

In order to avoid interest charges, the tax authorities must receive the instalment payments no later than the date indicated on the attached schedule.

**NOTICES OF ASSESSMENT**

If your Company receives a Notice of Assessment which does not agree with a return as prepared by us, please contact us so that we can determine whether any action should be taken. The Company has only a limited number of days (90 days in the case of federal, Ontario) from the date of mailing of the Assessment in which to object. Failure to respond within the prescribed time limit will cause the Company to lose its right to object to the Assessment.

If you have any questions concerning these Returns, or if we may be of any further assistance, please feel free to contact the undersigned.

Yours Truly,

Michael Maedel

Michael Maedel, CPA, CA
*Senior Manager – KPMG Enterprise*
*(519) 251-3516*
*mmaedel@kpmg.ca*

MM:mm
Enclosures

# Enwin Utilities Ltd.

## Corporate Tax Return - Key Tax Attributes Summary

### 2018 Taxation Year

The following is a summary of a few select Key Tax Attributes for the income tax returns of Enwin Utilities Ltd. for the period ended December 31, 2018.

| Description | Current year 2018 | Prior year 2017 |
|---|---|---|
| Net income for accounting purposes (Sch 140, line 9999) | $13,508,482 | $3,340,035 |
| Net income for tax purposes (T2, line 300) | $15,375,402 | $14,468,638 |
| Taxable income (T2, line Z) | $15,363,245 | $14,417,162 |
| Total SR&ED Expenditures (T661, line 511) | $577,170 | |
| Total Qualified SR&ED Expenditures for Federal ITC purposes (T661, line 570) | $506,564 | |
| **Federal and Provincial Taxes** | | |
| Part I (T2, line 700) | $2,363,093 | $2,155,258 |
| Investment tax credit against Part I (T2, line 652) | $91,985 | $80,305 |
| Part IV (T2, line 712) | $2,015 | $5,428 |
| Dividend refund (T2, line 784) | $197,241 | $102,450 |
| Ontario taxes (T2, line 760) | $1,748,400 | $1,641,458 |
| **Carryforward Closing Balances** | | |
| Refundable Dividend Tax On Hand (T2, line 485) | $197,241 | $102,450 |
| Undepreciated Capital Cost (Sch 8, line 220) | $198,366,176 | $198,349,703 |
| General Rate Income Pool (Sch 53, line 590) | $67,619,696 | $57,011,315 |
| Capital Dividend Account (Sch 89, line K) | $305,819 | $279,159 |

**Scientific Research & Experimental Development (SR&ED)**

| Description | Current year 2018 |
|---|---|
| **Investment Tax Credit Attributes** | |
| Federal Investment Tax Credit (Sch 31, line 540) | $75,985 |
| Ontario Research & Development Tax Credit (Sch 31, line 540) | $18,373 |
| Ontario Business Research Institute Tax Credit (Sch 5, line 470) | $8,000 |

Pursuing any potential opportunities that may be identified through a review of the Key Tax Attributes Summary is outside the scope of any existing engagement letter with KPMG. Should you wish to pursue any potential opportunities we would be pleased to meet with you to discuss your needs and then provide you with a new tax advisory engagement letter detailing the scope of services and fees agreed upon in further pursuing such potential opportunities. KPMG will take no further action with respect to any potential opportunities, except as specifically engaged to do so by you pursuant to a tax advisory engagement letter.

*All of the amounts included on this schedule are based on what the Company has reported in its current income tax return. Before any planning is undertaken certain amounts will need to be confirmed with the relevant tax authorities.*

# Enwin Utilities Ltd.

# Corporate Income Tax Filing Instructions

## 2018 Taxation Year

We enclose the following income tax returns of Enwin Utilities Ltd. (the “Company”) for the period ended December 31, 2018:

- ☑ T2 – *Corporation Income Tax Return*
- ☑ One copy of the federal, any applicable provincial return(s) and Form *T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim (Federal)* for your files. For filing purposes, Form T661 information will be electronically transmitted to the Canada Revenue Agency along with the other corporate tax information.
- ☑ Instalment Schedules

We have prepared these returns based on our understanding of and reliance upon the facts, data, materials, assumptions and other information (collectively, the “Information”) provided to us by the Company and/or its representatives, and we have not independently investigated or verified the accuracy or completeness of such Information. We accept no responsibility or liability for any errors attributable to our reliance upon inaccurate or incomplete Information. We recommend that you carefully review the returns in their entirety to ensure that all of the relevant Information is correctly and completely disclosed.

When you are satisfied that the returns are in order, one copy of each return should be retained for your records (the “Client Copy”) and the remaining copies should be completed by an authorized signing officer of the Company and filed as described below.

We suggest that any paper filed returns be sent by you by registered mail and that the receipt be kept on file in order to have evidence of the date of filing.

### *T2 - CORPORATION INCOME TAX RETURN (FEDERAL)*

#### *Signature*

Form T2 – Corporate Income Tax Return, the certification section at the bottom of page 8 should be completed and signed.

#### *Mailing*

One copy of the T2 Corporate Income Tax Return must be received by The Ministry of Finance, HYDRO PIL DIVISION, P.O. Box 620, 33 King Street West, Oshawa, Ontario, L1H 8E9 no later than June 30, 2018. The Company’s account number should be recorded on each of the paper documents submitted.

#### *Refund*

A refund of $**344,323** is claimed and therefore no amount is payable for the **2018** taxation year.

Canada Revenue Agency / Agence du revenu du Canada

Code 1501

# Scientific Research and Experimental Development (SR&ED) Expenditures Claim

**Use this form:**
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

**To claim an ITC, use either:**
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

## Part 1 – General information

**010** Name of claimant: Enwin Utilities Ltd.

Enter one of the following:
86712 0586 RC0002 — Business number (BN)
Social insurance number (SIN): 

Tax year
From: 2018-01-01 (Year Month Day)
To: 2018-12-31 (Year Month Day)

**050** Total number of projects you are claiming this tax year: 1

| | | |
|---|---|---|
| **100** Contact person for the financial information: Heather Malcolm-Kiss | **105** Telephone number/extension: (519) 255-2888 | **110** Fax number: (519) 255-7423 |
| **115** Contact person for the technical information: Marc Ethier | **120** Telephone number/extension: (519) 255-2888 | **125** Fax number: (519) 255-7423 |

**151** If this claim is filed for a partnership, was Form T5013 filed? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

| **153** Names of the partners | **156** % | **157** BN or SIN |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |

## Part 2 - Project information

CRA internal form identifier 060
Code 1501

**Complete a separate Part 2 for each project claimed this year.**

### Section A - Project identification

**200** Project title (and identification code if applicable)
See schedule

## Part 3 – Calculation of SR&ED expenditures

**What did you spend on your SR&ED projects?**

### Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

**160** 1 [X] I elect to use the proxy method
(Enter "0" on line 360 and complete Part 5.)

**162** 1 [ ] I choose to use the traditional method
(Enter "0" on lines 355 and 502. Complete line 360.)

### Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

| | | | |
|---|---|---|---|
| • SR&ED portion of salary or wages of employees directly engaged in the SR&ED: | | | |
| a) Employees other than specified employees for work performed in Canada | 300 | + | 231,796 |
| b) Specified employees for work performed in Canada | 305 | + | |
| **Subtotal** (add lines 300 and 305) | 306 | = | 231,796 |
| c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide) | 307 | + | |
| d) Specified employees for work performed outside Canada (subject to limitations – see guide) | 309 | + | |
| • Salary or wages identified on line 315 in prior years that were paid in this tax year | 310 | + | |
| • Salary or wages incurred in the year but not paid within 180 days of the tax year end | 315 | | |
| • Cost of materials consumed in performing SR&ED | 320 | + | |
| • Cost of materials transformed in performing SR&ED | 325 | + | |
| • Contract expenditures for SR&ED performed on your behalf: | | | |
| a) Arm's length contracts (see note 1) | 340 | + | 171,166 |
| b) Non-arm's length contracts (see note 1) | 345 | + | |
| • Lease costs of equipment used **before 2014**: | | | |
| a) All or substantially all (90% of the time or more) for SR&ED | 350 | + | |
| b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method) | 355 | + | |
| • Overhead and other expenditures (enter "0" if you use the proxy method) | 360 | + | |
| • Third-party payments (see note 2) (complete Form T1263*) | 370 | + | 50,000 |
| **Total current SR&ED expenditures** (add lines 306 to 370; do not add line 315) (Corporations may need to adjust line 118 of schedule T2SCH1) | 380 | = | 452,962 |
| • Capital expenditures for depreciable property available for use **before 2014** (Do not include these capital expenditures on schedule T2SCH8) | 390 | + | |
| **Total allowable SR&ED expenditures** (add lines 380 and 390) | 400 | = | 452,962 |

### Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

| | | | |
|---|---|---|---|
| Amount from line 400 | 420 | | 452,962 |
| **Deduct** | | | |
| • provincial government assistance for expenditures included on line 400 | 429 | – | 22,026 |
| • other government assistance for expenditures included on line 400 | 431 | – | |
| • non-government assistance for expenditures included on line 400 | 432 | – | |
| • SR&ED ITCs applied and/or refunded in the prior year (see guide) | 435 | – | 68,305 |
| • sale of SR&ED capital assets and other deductions | 440 | – | |
| **Subtotal** (line 420 minus lines 429 to 440) | 442 | = | 362,631 |
| **Add** | | | |
| • repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool | 445 | + | |
| • prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661) | 450 | + | |
| • SR&ED expenditure pool transfer from amalgamation or wind-up | 452 | + | |
| • amount of SR&ED ITC recaptured in the prior year | 453 | + | |
| **Amount available for deduction** (add lines 442 to 453) (enter positive amount only, include negative amount in income) | 455 | = | 362,631 |
| • Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1) | 460 | – | 362,631 |
| **Pool balance of deductible SR&ED expenditures to be carried forward to future years** (line 455 minus 460) | 470 | = | |

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Note 1 – For contract expenditures made after 2013, no amounts for purchasing or leasing capital property can be included.

Note 2 – For third-party payments made after 2013, no amounts for purchasing or leasing capital property can be included.

## Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

**The resulting amount is used to calculate your refundable and/or non refundable ITC.**

**Enter the breakdown between current and capital expenditures (to the nearest dollar)**

| | Line | Current Expenditures | Line | Capital Expenditures |
|---|---|---|---|---|
| **Total expenditures for SR&ED** (from lines 380 and 390) | 492 | 452,962 | 496 | |
| **Add** | | | | |
| • payment of prior years' unpaid amounts (other than salary or wages) (see note 5) | 500 + | | | |
| • prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method) | 502 + | 124,208 | | |
| • expenditures on shared-use equipment for property acquired **before 2014** | | | 504 + | |
| • qualified expenditures transferred to you (see note 3) (complete Form T1146**) | 508 + | | 510 + | |
| **Subtotal** (add lines 492 to 508, and add lines 496 to 510) | 511 = | 577,170 | 512 = | |
| **Deduct (see note 4)** | | | | |
| • provincial government assistance | 513 – | 26,373 | 514 – | |
| • other government assistance | 515 – | | 516 – | |
| • non-government assistance and contract payments | 517 – | | 518 – | |
| • current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see note 5) | 520 – | | | |
| • amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier | 528 – | | | |
| • 20% of expenditures included on lines 340 and 370 | 529 – | 44,233 | | |
| • prescribed expenditures not allowed by regulations (see guide) | 530 – | | 532 – | |
| • other deductions (see guide) | 533 – | | 535 – | |
| • non-arm's length transactions | | | | |
| – assistance allocated to you (complete Form T1145*) | 538 – | | 540 – | |
| – expenditures for non-arm's length SR&ED contracts (from line 345) | 541 – | | | |
| – adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide) | 542 – | | 543 – | |
| – qualified expenditures you transferred (complete Form T1146**) | 544 – | | 546 – | |
| **Subtotal** (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546) | 557 = | 506,564 | 558 = | |
| **Qualified SR&ED expenditures** (add lines 557 and 558) | | | 559 = | 506,564 |
| **Add** | | | | |
| • repayments of assistance and contract payments made in the year | | | 560 + | |
| **Total qualified SR&ED expenditures for ITC purposes** (add lines 559 and 560) | | | 570 = | 506,564 |

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Note 3 – On line 510 (capital) – Only include expenditures made before 2014 by the transferor (performer). Complete the latest version of Form T1146.

Note 4 – On lines 514, 516, 518, 532, 535, 540, 543 and 546 – Only include amounts related to expenditures of a capital nature made before 2014.

Note 5 – For arm's length contracts, only include 80% of the contract amount.

## Part 5 – Calculation of prescribed proxy amount (PPA)

**A notional amount representing your overhead and other expenditures.**

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

### Section A – Salary base

| | | | |
|---|---|---|---|
| Salary or wages of employees other than specified employees (from lines 300 and 307) | 810 | + | 231,796 |
| **Deduct** | | | |
| Bonuses, remuneration based on profits, and taxable benefits that were included on line 810 | 812 | – | 5,964 |
| **Subtotal** (line 810 minus 812) | 814 | = | 225,832 |

**Salary or wages of specified employees**

| 850 | 852 | 854 | 856 | 858 | 860 |
|---|---|---|---|---|---|
| **Column 1** | **Column 2** | **Column 3** | **Column 4** | **Column 5** | **Column 6** |
| Name of specified employee | Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar) | % of time spent on SR&ED (maximum 75%) | Amount in column 2 multiplied by percentage in column 3 | 2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year | Amount in column 4 or 5, whichever amount is less |
| | | | | | |

(Enter total of column 6 on line 816) **816** +

| | | | |
|---|---|---|---|
| **Salary base** (total of lines 814 and 816) | 818 | = | 225,832 |

### Section B – Prescribed proxy amount (PPA)

| | | | |
|---|---|---|---|
| Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year, and less 10% of the salary base for number of days after 2013 in the tax year (use the formula in the guide-line 820) | 820 | = | 124,208 |

**Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.**

**(See the guide for explanation and example of the overall cap on PPA)**

## Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

| 750 | 752 | 754 | 756 |
|---|---|---|---|
| Project title or identification code | Salary or wages in the tax year (Total of lines 306 to 309) | Cost of materials in the tax year (Total of lines 320 and 325) | Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345) |
| 1. 2018-01 Smart Grid Integration Techniques | 231,796 | | 171,166 |
| **Total** | 231,796 | | 171,166 |

## Part 7 – Additional information

**Expendítures for SR&ED performed by you in Canada** (line 400 minus lines 307, 309, 340, 345, and 370) . . . . . . . . . . . **605** 231,796

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

| | | Canadian (%) | | Foreign (%) |
|---|---|---|---|---|
| Internal | 600 | 100.000 | | |
| Parent companies, subsidiaries, and affiliated companies | 602 | | 604 | |
| Federal grants (do not include funds or tax credits from SR&ED tax incentives) | 606 | | | |
| Federal contracts | 608 | | | |
| Provincial funding | 610 | | | |
| SR&ED contract work performed for other companies on their behalf | 612 | | 614 | |
| Other funding (e.g., universities, foreign governments) | 616 | | 618 | |

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

**620** 1 [ ] Basic or Applied research **622** 1 [X] Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

| | | |
|---|---|---|
| Scientists and engineers | 632 | 1 |
| Technologists and technicians | 634 | 2 |
| Managers and administrators | 636 | 1 |
| Other technical supporting staff | 638 | 1 |

## Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . X
3. completed Part 2 for each project . . . X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* . . . X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . X
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed . . . X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . X

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third·Party Payments for Scientific Research and Experimental Development (SR&ED)*

## Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

**A $1000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.**

**935 Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?**

1 [X] Yes (complete the claim preparer information table and lines 970 and 975 below)

2 [ ] No (complete lines 970 and 975)

**Claim preparer information table**

| 940 | 945 | 950 | 955 | 960 | 965 |
|---|---|---|---|---|---|
| Name of claim preparer (company or individual) | Business number | Billing arrangement code (see codes*) | Billing rate (percentage, hourly/daily rate or flat fee) | Other billing arrangement(s) (Maximum 10 words) | Total fee paid, payable, or expected to pay |
| 1. | | | | | |
| 2. | | | | | |
| | | | | **Total** | |

*** Billing arrangement codes**

| Code | Type of billing arrangement |
|---|---|
| 1 | Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned |
| 2 | Hourly rate |
| 3 | Daily rate |
| 4 | Flat fee arrangement (lump sum) |
| 5 | Other arrangements – describe the arrangement in box 960 in 10 words or less |

**970** I, Helga Reidel, certify that the information provided in this part is complete and accurate.
Name of authorized signing officer of the corporation, or individual (print)

Signature

**975** 2019-06-14
Year Month Day

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

## Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

**165** Helga Reidel
Name of authorized signing officer of the corporation, or individual

Signature

**170** 2019-06-14
Date

**175** KPMG LLP
Name of person/firm who completed this form

**Privacy Notice**

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 "Scientific Research and Experimental Development" in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act*, and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our *Info Source* chapter can be found at www.cra.gc.ca/atip.

Canada Revenue Agency    Agence du revenu du Canada

# THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

Complete this form for each third-party payment and attach it to Form T661.

For more information on third-party payments:

- See line 370 of Guide to Form T661, S*cientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

## Required Information

## 1. Identification

**701** Name of the third party
University of Windsor

**702** Address (Street number and name)
401 Sunset Avenue

| City | Province / Territory | Postal Code |
|---|---|---|
| Windsor | ON | N9B 3P4 |

**704** Total amount paid in the year
$ 50,000

Identify the research project(s) performed by the third-party entity for the payment

**706** Project title (and identification code if applicable)
1 2018-01 Smart Grid Integration Techniques

Check the appropriate box to indicate the type of entity:

| | | | |
|---|---|---|---|
| 711 | Approved association | 1 Yes [ ] | |
| 712 | Non-profit SR&ED corporation resident in Canada | 1 Yes [ ] | |
| 714 | An approved university, college, research institute, or other similar institution | 1 Yes [X] | |
| 716 | Granting council | 1 Yes [ ] | |
| 718 | Other corporation resident in Canada | 1 Yes [ ] | |
| 721 | Are you dealing at arm's length with the recipient? | 1 Yes [X] | 2 No [ ] |

## 2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

| | | |
|---|---|---|
| 731 | Experimental development | 1 Yes [X] |
| 732 | Applied research | 1 Yes [ ] |
| 734 | Basic research | 1 Yes [ ] |

**736** Briefly explain what the payment is for:
Research in a novel quantitative non-destructive quality evaluation of advanced joining & consolidation manufacturing processes such as low pressure cold spray technology

**738** Briefly explain how the SR&ED is related to a business that you carry on:

Traditional practice for non-reliability related issues
is run-to-failure equipment. Low pressure cold spray
technology is an alternative to allow remediation.

**740** Briefly explain how you are entitled to exploit the results of the SR&ED:

Access to all experimental results; prototype testing on
distribution assets such as transformers

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 “Scientific Research and Experimental Development”, in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act* and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our Info Source chapter can be found at **http://www.cra.gc.ca/atip/**.

T1263 E (15)

Canada

## Part 2 – Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1501

**Complete a separate Part 2 for each project claimed this year.**

### Section A – Project identification

**200** Project title (and identification code if applicable)

2018-01 Smart Grid Integration Techniques

| **202** Project start date | **204** Completion or expected completion date | **206** Field of science or technology code (See guide for list of codes) |
|---|---|---|
| 2016-04 (Year Month) | 2019-06 (Year Month) | 2.02.01 Electrical and electronic engineering |

Project claim history

**208** 1 [X] Continuation of a previously claimed project  **210** 1 [ ] First claim for the project

**218** Was any of the work done jointly or in collaboration with other businesses? . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

| **220** Names of the businesses | **221** BN |
|---|---|
| 1 | |
| 2 | |
| 3 | |

### Section B – Project descriptions

**242** What scientific or technological uncertainties did you attempt to overcome?
(*Maximum 50 lines*)

EnWin Utilities Ltd. (EnWin or the Company) is an electricity distribution company which delivers power to residential and industrial customers in Windsor, Ontario. EnWin sought to improve the Company's distribution system through the integration of smart grid technologies and third-party/proprietary systems not inherently designed to work together. Following technological obstacles were encountered:

OMS & Systems Integration:
EnWin sought to develop an efficient smart grid monitoring architecture that would provide integration between disparate-systems (OMS, SCADA, Smart Meters, GIS etc.) while achieving near real-time outage event detection during potentially catastrophic events. The underlying challenge was how to reliably synchronize disparate systems and efficiently process multiple-stochastic-elements pertaining to outages. This issue reflected in the performance of the outage alarms, as the meters are often over or under reporting the failures. Traditional methods to improve the alarms rate like network optimization, SCADA frequency interference removal, tuning communication/transmit mode failed to improve the predictions. On the other hand, while attempting to integrate OMS-responder system with GIS to overlay outages on GIS maps, the system encountered crashes while inputs were fed-in from SCADA, AMI and storm simulations. Attempts were made to integrate the GIS system with ODS (Operational Data store- where data from smart grid systems stored) but this was challenging as the ODS embodies a multitude of data coming from various systems. Consequently, EnWin was uncertain if a smart grid architecture could be achieved given the randomness of events and sub-system constraints that compromised integration efforts.

Backflow Inspection:
EnWin sought to develop a geo-spatial platform that would provide the ability to monitor backflows due to pressure differentials in piping networks. Extending the legacy GIS system for this purpose was non-routine as the system would need to accommodate various uncategorized endpoints. The geo-spatial

**242** What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

system in place had not been designed to support hydraulics where intrinsic properties of pipe flow would need to be incorporated, and therefore compelled investigations to understand unknown parametric relationships.

**244** What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

OMS and Transformer Loading/Systems Integration:

EnWin continued to investigate techniques to improve the forecasting capability of their OMS. The outage management/prediction system is being designed to ingest data and signals from thousands of smart meters, IVR, GIS and the SCADA network for either pinpointing or predicting faults. Intricate cross-validations across the systems are required to generate tangible alarms that are representative of true faults. Some analytical and system achievements had been conceptualized around integrations, analytics and algorithms to characterize faults. But in March 2018, during a live significantly large outage event, the alarms from meters were coming in 10 to 40 seconds earlier than signals from the SCADA system for a colossal population of smart meters, which led to the inability to properly validate outages. Early reporting meters created their own incidents in OMS and overwhelmed the system such that the real SCADA device outages are buried. The amount of alarms propagating through interfaces contributed to over/under prediction due to this variation. Investigations revealed that the endpoints in the mixed transmit configuration was prone to mischaracterizing false alarms. It was hypothesized that filtering algorithms could detect the last gasp transmissions accurately to detect the hold off time of the meters. As part of the proof of concept, to overlay the results spatially, GIS system was integrated with the metering system to show the meter alarms in the map accurately. Testing the hypothesis revealed that about a large population of the smart meters would ignore the power failure after 120 seconds hold off as opposed to 64 seconds which ultimately made the OMS system to receive some events late, which caused the OMS to record events prior to SCADA event. It was identified that the alarm type could be identified in the transmission interface but not in the multi-speak protocol or in the alarm report. It was reasoned that it was possible to determine the threshold values from the meter by reading the ping frequency.  To achieve this, 32 second outage hold off was activated to offset the alarms that would come in earlier to help with the rollup in OMS.  However, while testing the status messages coming through the towers, the message count increased but the responses were missed. Analysis of heat maps showed that meters outside of 2 km radius from the transmission point experienced low SNR values. Enwin analysed sectoring the network to boost the alarm performance and utilizing the GIS network model along with the signal strength information to determine the performance of meters on every endpoint transformer Testing will be continued in next fiscal year to convert the omni-directional antennas into several directional antennas with possible down-tilt to help reducing contention and improve performance.

Backflow Inspection website:

Initial investigations focused on developing a backflow inspection data model which could streamline the data into the GIS system to overlay the data received from the endpoints in real-time on the respective spatial co-ordinates. The work focused on extending the GIS to have a mechanism to capture new field data (e.g., geo-spatial parameters) related to the piping network. A queuing mechanism was developed to ingest ingress data from inspection points to the backend-system for rendering geo-spatial maps. Inspection was done in real-time using pressure differential formulas and the

**244** What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

results were mapped spatially to the GIS to automatically trigger report to be transmitted to the endpoints. In the process, performance challenges arose in how to handle the density of geo-spatial rendering of varying granularity of piping related computations. Additionally it was challenging to identify the type of the end-points zoned under different categories. Experimentation will therefore be continued in the next FY.

**246** What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

The work performed for this project represents a technological advancement in the field of Electrical Engineering.

If successful, the work performed would result in the following advancements:

OMS and SI:
EnWin's work advanced the company's understanding of techniques to reliably predict outages through the appropriate orchestration of alarm transmissions from smart meters. EnWin gained understanding in how to correlate certain data footprints from disparate systems (GIS, ODS, SCADA) to increase the timely restoration of outages.

Backflow:
If successful, EnWin's work will improve the Company's understanding of how to integrate the baseline geo-spatial system with the backflow inspection real-time data to monitor backflows that are created due to pressure differentials in piping networks. This knowledge allowed EnWin to resolve the interoperability issues with disparate systems and GIS notifications in real-time.

## Section C – Additional project information

Who prepared the responses for Section B?

| | | | |
|---|---|---|---|
| **253** 1 ☐ Employee directly involved in the project | **254** Name | | |
| **255** 1 ☐ Other employee of the company | **256** Name | | |
| **257** 1 ☒ External consultant | **258** Name: KPMG LLP | **259** Firm: KPMG LLP | |

List the key individuals directly involved in the project and indicate their qualifications/experience.

| | **260** Names | **261** Qualifications/experience and position title |
|---|---|---|
| 1 | Ethier, Marc | Project Manager, B.C.S., M.B.A Sr. Technical Analyst, Systems Development 18+ Years IT experience. |
| 2 | Hales, Christine | Senior Technical Analyst, B.C.S. Hons, 22+ Years IT experience |
| 3 | Reaume, Nicole | GIS Analyst, B.A.Sc with 9+ years of IT experience |

**265** Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . . . . . . . . . . . . . . . . . . . . . 1 ☐ Yes 2 ☒ No

**266** Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . . . . . . . . . . . . . . . . . . . . . 1 ☐ Yes 2 ☒ No

**267** Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . . . . . . . . . . . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

| 268 Names of individuals or companies | 269 BN |
|---|---|
| 1 Esri Canada | 89521 0979 RT0001 |
| 2 | |

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

| | | | |
|---|---|---|---|
| 270 1 | X Project planning documents | 276 1 | X Progress reports, minutes of project meetings |
| 271 1 | Records of resources allocated to the project, time sheets | 277 1 | X Test protocols, test data, analysis of test results, conclusions |
| 272 1 | Design of experiments | 278 1 | Photographs and videos |
| 273 1 | Project records, laboratory notebooks | 279 1 | Samples, prototypes, scrap or other artefacts |
| 274 1 | X Design, system architecture and source code | 280 1 | X Contracts |
| 275 1 | Records of trial runs | 281 1 | Others, specify 282 |

# Federal Tax Instalments

## Federal tax instalments

**For the taxation year ended** 2019-12-31

**Business number** 86712 0586 RC0002

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

Instalment payments can be made using one of the following methods:

- electronically, using your online or telephone banking services;
- online, using the CRA's *My Payment* service, at **canada.ca/cra-my-payment**;
- by setting up a pre-authorized debit agreement, in *My Business Account*, at **canada.ca/my-cra-business-account**;
- in person, at a Canadian financial institution, **by presenting the appropriate remittance voucher** with your payment.

You can also mail a cheque or a money order payable to the Receiver General of Canada, **accompanied by the appropriate remittance voucher**, to Canada Revenue Agency, P.O. Box 3800, Station A, Sudbury ON P3A 0C3.

## Monthly instalment workchart

| Date | Monthly tax instalments | Refund transferred to instalments | Instalments paid | Cumulative difference | Instalments payable |
|---|---|---|---|---|---|
| 2019-01-31 | 308,324 | | 316,393 | -8,069 | |
| 2019-02-28 | 308,324 | | 338,303 | -38,048 | |
| 2019-03-31 | 339,802 | | 316,393 | -14,639 | |
| 2019-04-30 | 339,802 | | | | 325,163 |
| 2019-05-31 | 339,802 | | | | 339,802 |
| 2019-06-30 | 339,802 | | | | 339,802 |
| 2019-07-31 | 339,802 | | | | 339,802 |
| 2019-08-31 | 339,802 | | | | 339,802 |
| 2019-09-30 | 339,802 | | | | 339,802 |
| 2019-10-31 | 339,802 | | | | 339,802 |
| 2019-11-30 | 339,802 | | | | 339,802 |
| 2019-12-31 | 339,801 | | | | 339,801 |
| 2020-01-31 | | | | | 342,625 |
| 2020-02-29 | | | | | 342,625 |
| | | | | | |
| **Totals** | 4,014,667 | | 971,089 | | 3,728,828 |

Canada Revenue Agency / Agence du revenu du Canada

# Information Return for Corporations Filing Electronically

- You have to complete this return for every initial and amended T2 Corporation Income Tax Return electronically filed to the Canada Revenue Agency (CRA) on your behalf.
- By completing Part 2 and signing Part 3, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part 4 must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy in your own records for six years.
- **Do not submit** this form to the CRA unless we ask for it.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

## Part 1 – Identification

| Corporation's name | Business number |
|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 |

| Tax year | From (Y M D) | To (Y M D) | Is this an amended return? |
|---|---|---|---|
| | 2018-01-01 | 2018-12-31 | Yes ☐ No ☒ |

## Part 2 – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

| | |
|---|---|
| Net income (or loss) for income tax purposes from Schedule 1, financial statements, or GIFI (line 300) | 15,375,402 |
| Part I tax payable (line 700) | 2,363,093 |
| Part II surtax payable (line 708) | |
| Part III.1 tax payable (line 710) | |
| Part IV tax payable (line 712) | 2,015 |
| Part IV.1 tax payable (line 716) | |
| Part VI tax payable (line 720) | |
| Part VI.1 tax payable (line 724) | |
| Part XIV tax payable (line 728) | |
| Net provincial and territorial tax payable (line 760) | 1,651,574 |

## Part 3 – Certification and authorization

@CRA **Sign up for online mail!** Get your CRA mail electronically delivered in My Business Account at **cra.gc.ca/mybusinessaccount**

I understand that by providing an email address, I am **registering** the corporation for the 'Manage online mail' service. I understand and agree that all notices and other correspondence eligible for electronic delivery will no longer be printed and mailed. The CRA will notify the corporation at this email address when they are available in My Business Account and requiring immediate attention. They will be presumed to have been received on the date that the email is sent.

**Email address** for online mail (optional): ____________________

I, Reidel (Last name), Helga (First name), CEO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part 4 to electronically file the corporation income tax return identified in Part 1. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

| Date (yyyy/mm/dd) | Signature of an authorized signing officer of the corporation | Telephone number |
|---|---|---|
| 2019-06-14 | | (519) 255-2869 |

## Part 4 – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part 1.

| Name of person or firm | Electronic filer number |
|---|---|
| KPMG LLP | |

## Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial 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 the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Canada Revenue Agency / Agence du revenu du Canada

# T2 Corporation Income Tax Return

**200**

**055** Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

## Identification

**Business number (BN)** . . . . . . . . . . **001** 86712 0586 RC0002

**Corporation's name**
**002** Enwin Utilities Ltd.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . **010** Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
**011** 787 Ouellette Avenue
**012** PO Box 1625, Station A
City **015** Windsor
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal or ZIP code **018** N9A 5T7

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . **020** Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
**021** c/o
**022**
**023**
City **025**
Province, territory, or state **026**
Country (other than Canada) **027**
Postal or ZIP code **028**

**Location of books and records** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . **030** Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
**031** 787 Ouellette Avenue
**032** PO Box 1625 Station A
City **035** Windsor
Province, territory, or state **036** ON
Country (other than Canada) **037**
Postal or ZIP code **038** N9A 5T7

**040** **Type of corporation at the end of the tax year** (tick one)
[X] 1 Canadian-controlled private corporation (CCPC)
[ ] 2 Other private corporation
[ ] 3 Public corporation
[ ] 4 Corporation controlled by a public corporation
[ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . **043** Year Month Day

**To which tax year does this return apply?**
Tax year start **060** Year Month Day 2018-01-01
Tax year-end **061** Year Month Day 2018-12-31

**Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060?** . . . . . . . . . . . . . . **063** Yes [ ] No [X]

If **yes**, provide the date control was acquired . . . . . . . . . . . . . **065** Year Month Day

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . . **066** Yes [ ] No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . . **067** Yes [ ] No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . **070** Yes [ ] No [X]
Amalgamation? . . . . . . . . . . . . . . . **071** Yes [ ] No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . **072** Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . . **076** Yes [ ] No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . **078** Yes [ ] No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . **079**

**Is the corporation a resident of Canada?** **080** Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
**081**

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . **082** Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
**085**
[ ] 1 Exempt under paragraph 149(1)(e) or (l)
[ ] 2 Exempt under paragraph 149(1)(j)
[ ] 3 Exempt under paragraph 149(1)(t) (for tax years starting before 2019)
[ ] 4 Exempt under other paragraphs of section 149

**Do not use this area**
**095** **096** **898**

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| | | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations? | 170 | | 29 |
| Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Does the corporation earn income from one or more Internet web pages or websites? | 180 | | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine? | 202 | X | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | X | 3 |
| Is the corporation claiming any type of losses? | 204 | | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | X | 6 |
| i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)? | 207 | X | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves? | 213 | X | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits? | 221 | X | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | X | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | ——— |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II – Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments (continued)

| | | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | X | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | | Yes | | No | |
|---|---|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | Yes | X | No | |
| Is the corporation inactive? | 280 | Yes | | No | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| | | | |
|---|---|---|---|
| 284 | Power distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | | Yes | | No | |
|---|---|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | Yes | | No | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | Yes | | No | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | Yes | | No | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 Yes No

## Taxable income

| | | | | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI | 300 | | 15,375,402 | A |
| **Deduct:** | | | | |
| Charitable donations from Schedule 2 | 311 | 6,900 | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine made before March 22, 2017, from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | 5,257 | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | 12,157 ▶ | 12,157 | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | 15,363,245 | C |
| Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | 15,363,245 | |
| Income exempt under paragraph 149(1)(t) (for tax years starting before 2019) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | 15,363,245 | Z |
| **Taxable income** for the year from a personal services business | | | | Z.1 |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income eligible for the small business deduction from Schedule 7 . . . . . 400 14,733,473 A

Taxable income from line 360 on page 3, **minus** 100/28 ( 3.57143 ) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . 405 15,362,931 B

Business limit (see notes 1 and 2 below) . . . . . 410 500,000 C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction**

**Taxable capital business limit reduction**

Amount C 500,000 x 415 *** 695,030 D / 11,250 = . . . . . 30,890,222 E

**Passive income business limit reduction**

Adjusted aggregate investment income from Schedule 7**** . 417 ______ – 50,000 = . . ______ F

Amount C 500,000 / 100,000 x Amount F ______ = . . . . . ______ G

Subtotal (the greater of amount E and amount G) 422 30,890,222 H

Reduced business limit for tax years starting before 2019 (amount C **minus** amount E) (if negative, enter "0") . . . . . 425 ______ I

Reduced business limit for tax years starting after 2018 (amount C **minus** amount H) (if negative, enter "0") . . . . . 426 ______ J

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 on page 5) . . . . . ______ K

**Reduced business limit after assignment for tax years starting before 2019** (amount I **minus** amount K) . . . . . 427 ______ L

**Reduced business limit after assignment for tax years starting after 2018** (amount J **minus** amount K) . . . . . 428 ______ M

**Small business deduction**

**Tax years starting before 2019**

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year before January 1, 2018 ______ / Number of days in the tax year 365 x 17.5 % = ______ 1

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year after December 31, 2017, and before January 1, 2019 365 / Number of days in the tax year 365 x 18 % = ______ 2

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year after December 31, 2018 ______ / Number of days in the tax year 365 x 19 % = ______ 3

**Tax years starting after 2018**

Amount A, B, C, or M, whichever is the least . . . . ______ . . . . . x 19 % = ______ 4

**Small business deduction** (total of amounts 1 to 4) . . . . . 430 ______ N

Enter amount N at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations. For the first tax year starting after 2018, use the total of lines 744 of Schedule 7. Otherwise, use the total of lines 745 of the preceding tax year.

## Small business deduction (continued)

**Specified corporate income and assignment under subsection 125(3.2)**

| | O1<br>Name of corporation receiving the income and assigned amount | O<br>Business number of the corporation receiving the assigned amount<br>490 | P<br>Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column O [3]<br>500 | Q<br>Business limit assigned to corporation identified in column O [4]<br>505 |
|---|---|---|---|---|
| 1. | | | | |
| | | | Total 510 | Total 515 |

**Notes:**

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
 (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
 (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column P in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425 (426 for tax years starting after 2018).

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | 15,363,245 | A |
| Lesser of amounts 9B and 9H from Part 9 of Schedule 27 | | B | | |
| Amount 13K from Part 13 of Schedule 27 | | C | | |
| Personal services business income 432 | | D | | |
| Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least | | E | | |
| Aggregate investment income from line 440 on page 6* | 636,672 | F | | |
| Subtotal (**add** amounts B to F) | 636,672 | ► | 636,672 | G |
| Amount A **minus** amount G (if negative, enter "0") | | | 14,726,573 | H |
| **General tax reduction for Canadian-controlled private corporations** – Amount H **multiplied** by 13 % | | | 1,914,454 | I |

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | J |
| Lesser of amounts 9B and 9H from Part 9 of Schedule 27 | | K | | |
| Amount 13K from Part 13 of Schedule 27 | | L | | |
| Personal services business income 434 | | M | | |
| Subtotal (**add** amounts K to M) | | ► | | N |
| Amount J **minus** amount N (if negative, enter "0") | | | | O |
| **General tax reduction** – Amount O **multiplied** by 13 % | | | | P |

Enter amount P on line 639 on page 8.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Aggregate investment income from Schedule 7 | 440 | 636,672 x 30 2/3 % = | 195,246 | A |
| Foreign non-business income tax credit from line 632 on page 8 | | 88 | | B |
| Foreign investment income from Schedule 7 | 445 | 849 x 8 % = 68 | | C |
| Subtotal (amount B **minus** amount C) (if negative, enter "0") | | 20 ▶ | 20 | D |
| Amount A **minus** amount D (if negative, enter "0") | | | 195,226 | E |
| Taxable income from line 360 on page 3 | | 15,363,245 | | F |
| Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least | | | | G |
| Foreign non-business income tax credit from line 632 on page 8 | | 88 x 75 / 29 = 228 | | H |
| Foreign business income tax credit from line 636 on page 8 | | x 4 = | | I |
| Subtotal (**add** amounts G to I) | | 228 ▶ 228 | | J |
| Subtotal (amount F **minus** amount J) (if negative, enter "0") | | 15,363,017 K x 30 2/3 % = | 4,711,325 | L |
| Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) | | | 2,363,093 | M |
| **Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least | 450 | | 195,226 | N |

## Refundable dividend tax on hand (for tax years starting before 2019)

| | | | | |
|---|---|---|---|---|
| Refundable dividend tax on hand at the end of the previous tax year | 460 | 102,450 | | |
| Dividend refund for the previous tax year | 465 | 102,450 | | |
| Subtotal (line 460 **minus** line 465) | | ▶ | | O |
| Refundable portion of Part I tax from line 450 above | | 195,226 | | P |
| Total Part IV tax payable from Schedule 3 | | 2,015 | | Q |
| Net refundable dividend tax on hand transferred on an amalgamation or the wind-up of a subsidiary | 480 | | | |
| Subtotal (amount P **plus** amount Q**plus** line 480) | | 197,241 ▶ | 197,241 | R |
| **Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R | 485 | | 197,241 | |

## Dividend refund (for tax years starting before 2019)

**Private and subject corporations at the time taxable dividends were paid in the tax year**

| | | | |
|---|---|---|---|
| Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 | 3,000,000 x 38 1/3 % = | 1,150,000 | S |
| Refundable dividend tax on hand at the end of the tax year from line 485 above | | 197,241 | T |
| **Dividend refund** – Amount S or T, whichever is less | | 197,241 | U |

Enter amount U on line 784 on page 9.

## Refundable dividend tax on hand (for tax years starting after 2018)

| | | | | | |
|---|---|---|---|---|---|
| **Refundable dividend tax on hand** (RDTOH) at the end of the previous tax year | 460 | | | | |
| Dividend refund for the previous tax year | 465 | | | | |
| Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary | 480 | | | | |
| Subtotal (line 460 **minus** line 465 **plus** line 480) | | | | | A |
| General rate income pool (GRIP) at the end of the previous tax year (from line 100 of schedule 53) | | | | | B |
| Total eligible dividends paid in the previous tax year (from line 300 of schedule 53) | | | C | | |
| Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53) | | | D | | |
| Subtotal (amount C **minus** amount D) (if negative, enter "0") | | | ▶ | | E |
| Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0") | | | F | | |
| GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of schedule 53) | | | G | | |
| Subtotal (amount F **plus** amount G) | | | ▶ | | H |
| Amount H **multiplied** by 38 1 / 3 % | | | | | I |
| Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 ______ of the preceding tax year) | | | 520 | | J |
| Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 ______ of the preceding tax year) (if negative, enter "0") | | | 535 | | K |
| Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3) | | | L | | |
| Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3) | | | M | | |
| Subtotal (amount L **plus** amount M) | | | ▶ | | N |
| Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary | | | 525 | | O |
| ERDTOH dividend refund for the previous tax year | | | 570 | | P |
| Refundable portion of Part I tax (from line 450 on page 6) | | | | 195,226 | Q |
| Part IV tax before deductions (amount 2A from Schedule 3) | | | R | | |
| Part IV tax allocated to ERDTOH (amount N) | | | S | | |
| Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43) | | | T | | |
| Subtotal (amount R **minus** total of amounts S and T) | | | ▶ | | U |
| Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary | | | 540 | | V |
| NERDTOH dividend refund for the previous tax year | | | 575 | | W |
| 38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3) | | | | | X |
| Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter "0") | | | | | Y |
| **NERDTOH at the end of the tax year*** (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0") | | | 545 | | |
| Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** amount X **plus** amount U, if amount X is greater than amount U, otherwise, amount N.) (if negative, enter "0") | | | | | Z |
| **ERDTOH at the end of the tax year*** (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0") | | | 530 | | |

* For more information, consult the Help (F1).

## Dividend refund (for tax years starting after 2018)

| | | |
|---|---|---|
| 38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3) | | AA |
| ERDTOH balance at the end of the tax year (line 530) | | BB |
| **Eligible dividend refund** (amount AA or BB, whichever is less) | | CC |
| 38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3) | | DD |
| NERDTOH balance at the end of the tax year (line 545) | | EE |
| **Non-eligible dividend refund** (amount DD or EE, whichever is less) | | FF |
| Amount DD **minus** amount EE (if negative, enter "0") | | GG |
| Amount BB **minus** amount CC (if negative, enter "0") | | HH |
| **Additional non-eligible dividend refund** (amount GG or HH, whichever is less) | | II |
| **Dividend refund*** – Amount CC **plus** amount FF **plus** amount II | | JJ |

Enter amount JJ on line 784 on page 9.

* For more information, consult the Help (F1).

## Part I tax

| | | | | |
|---|---|---|---|---|
| Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % | | | 550 | 5,838,033 A |
| **Additional tax on personal services business income** (section 123.5) | | | | |
| Taxable income from a personal services business | 555 | x 5 % = | 560 | B |
| Recapture of investment tax credit from Schedule 31 | | | 602 | C |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | |
|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | 636,672 | D |
| Taxable income from line 360 on page 3 | 15,363,245 E | | |
| **Deduct:** | | | |
| Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least | F | | |
| Net amount (amount E **minus** amount F) | 15,363,245 ▶ | 15,363,245 | G |

| | | | |
|---|---|---|---|
| Refundable tax on CCPC's investment income – 10 2/3 % of whichever is less: amount D or amount G | 604 | 67,912 | H |
| Subtotal (**add** amounts A, B, C, and H) | | 5,905,945 | I |

**Deduct:**

| | | | |
|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | J |
| Federal tax abatement | 608 | 1,536,325 | |
| Manufacturing and processing profits deduction from Schedule 27 | 616 | | |
| Investment corporation deduction | 620 | | |
| Taxed capital gains 624 | | | |
| Federal foreign non-business income tax credit from Schedule 21 | 632 | 88 | |
| Federal foreign business income tax credit from Schedule 21 | 636 | | |
| General tax reduction for CCPCs from amount I on page 5 | 638 | 1,914,454 | |
| General tax reduction from amount P on page 5 | 639 | | |
| Federal logging tax credit from Schedule 21 | 640 | | |
| Eligible Canadian bank deduction under section 125.21 | 641 | | |
| Federal qualifying environmental trust tax credit | 648 | | |
| Investment tax credit from Schedule 31 | 652 | 91,985 | |
| Subtotal | | 3,542,852 ▶ | 3,542,852 K |

| | | |
|---|---|---|
| **Part I tax payable** – Amount I **minus** amount K | 2,363,093 | L |

Enter amount L on line 700 on page 9.

## Privacy statement

Personal information is collected under the Income Tax Act to administer tax, benefits, and related programs. It may also be used for any purpose related to the enforcement of the Act such as audit, compliance and collections activities. It may be shared or verified with 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 the right to access, or request 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 047 at **canada.ca/cra-info-source**.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from amount L on page 8 | 700 | 2,363,093 |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | 2,015 |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | 2,365,108 |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | 1,651,574 |
| Total tax payable | 770 | 4,016,682 A |

**Deduct other credits:**

| | | | | |
|---|---|---|---|---|
| Investment tax credit refund from Schedule 31 | | 780 | | |
| Dividend refund from amount U on page 6 or JJ on page 7 | | 784 | 197,241 | |
| Federal capital gains refund from Schedule 18 | | 788 | | |
| Federal qualifying environmental trust tax credit refund | | 792 | | |
| Canadian film or video production tax credit (Form T1131) | | 796 | | |
| Film or video production services tax credit (Form T1177) | | 797 | | |
| Tax withheld at source | | 800 | | |
| Total payments on which tax has been withheld | 801 | | | |
| Provincial and territorial capital gains refund from Schedule 18 | | 808 | | |
| Provincial and territorial refundable tax credits from Schedule 5 | | 812 | | |
| Tax instalments paid | | 840 | 4,163,764 | |
| Labour tax credit for qualifying journalism organizations | | | | |
| Total credits | | 890 | 4,361,005 | 4,361,005 B |

Balance (amount A **minus** amount B) -344,323

Refund code 894 1 Refund 344,323

If the result is negative, you have a **refund**.
If the result is positive, you have a **balance owing**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance owing . . . . . . .

For information on how to make your payment, go to **canada.ca/payments**.

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . . 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . . 920

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## Certification

I, 950 Reidel (Last name) 951 Helga (First name) 954 CEO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2019-06-14 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 255-2869 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 Yes ☒ No ☐

958 ______ Name of other authorized person 959 ______ Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

# Schedule of Instalment Remittances

Name of corporation contact: Helga Reidel
Telephone number: (519) 255-2869

| Effective interest date | Description (instalment remittance, split payment, assessed credit) | Amount of credit |
|---|---|---|
| | 2018 Installments | 3,663,764 |
| | Final payments | 500,000 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

**Total amount of instalments claimed (carry the result to line 840 of the T2 Return)** 4,163,764 **A**

**Total instalments credited to the taxation year per T9** 4,163,764 **B**

## Transfer

| | Account number | Taxation year end | Amount | Effective interest date | Description |
|---|---|---|---|---|---|
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 90,395,527 | 83,509,469 |
| | Total tangible capital assets | 2008 | + | 297,221,613 | 278,953,686 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 67,649,629 | 58,019,710 |
| | Total intangible capital assets | 2178 | + | 29,977,339 | 29,488,970 |
| | Total accumulated amortization of intangible capital assets | 2179 | – | 25,055,065 | 20,790,622 |
| | Total long-term assets | 2589 | + | 8,852,631 | 19,735,173 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 333,742,416 | 332,876,966 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 41,958,670 | 45,902,930 |
| | Total long-term liabilities | 3450 | + | 164,265,435 | 138,964,207 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 206,224,105 | 184,867,137 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | 127,518,311 | 148,009,829 |
| | **Total liabilities and shareholder equity** | 3640 | = | 333,742,416 | 332,876,966 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | 98,676,433 | 93,520,809 |

* Generic item

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Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| 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 | + | 301,297,635 | 304,018,382 |
| | Cost of sales | 8518 | – | 252,700,408 | 255,421,711 |
| | **Gross profit/loss** | 8519 | = | 48,597,227 | 48,596,671 |
| | Cost of sales | 8518 | + | 252,700,408 | 255,421,711 |
| | Total operating expenses | 9367 | + | 63,401,337 | 63,156,434 |
| | **Total expenses** (mandatory field) | 9368 | = | 316,101,745 | 318,578,145 |
| | Total revenue (mandatory field) | 8299 | + | 327,113,733 | 329,551,003 |
| | Total expenses (mandatory field) | 9368 | – | 316,101,745 | 318,578,145 |
| | **Net non-farming income** | 9369 | = | 11,011,988 | 10,972,858 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 11,011,988 | 10,972,858 |
| | **Total other comprehensive income** | 9998 | = | 5,352,858 | -4,231,983 |
| | **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 | – | 1,288,306 | 3,740,382 |
| | Future (deferred) income tax provision | 9995 | – | 1,568,058 | -339,542 |
| | Total – Other comprehensive income | 9998 | + | 5,352,858 | -4,231,983 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 13,508,482 | 3,340,035 |

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 141**

# Notes Checklist

| Corporation's name | Business number | Tax Year End Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012*, T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

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

Does the accountant have a professional designation? . . . . . **095** Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . . . **097** Yes [ ] No [X]

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

## Part 2 – Type of involvement with the financial statements

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

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** Yes [ ] No [X]

## 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 tax return (financial statements prepared by client) . . . . . 1 [ ]

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

Were notes to the financial statements prepared? . . . . . **101** Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** Yes [ ] No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** Yes [X] No [ ]

Is contingent liability information mentioned in the notes? . . . . . **106** Yes [X] No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** Yes [X] No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** Yes [ ] No [X]

## 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 (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . 200 Yes [ ] No [X]

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

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . 250 Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . 255 Yes [ ] No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . 260 Yes [ ] No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . 265 Yes [ ] No [X]

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

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

Reporting entity:

ENWIN Utilities Ltd. (the Corporation ) is a local distribution company that owns and operates the electricity distribution grid in the City of Windsor. In accordance with the Electricity Act, 1998, the Corporation was incorporated in December of 1999 under the Business Corporations Act (Ontario). The address of the Corporation s registered office is 787 Ouellette Avenue, Windsor, Ontario, Canada. The Corporation is 100% owned by Windsor Canada Utilities Ltd. ( WCUL ), which is in turn 100% owned by the Corporation of the City of Windsor (the City ).

On November 6, 2012, the Corporation and the Windsor Utilities Commission (the Commission ) entered into a Water System Operating Agreement ( WSOA ), whereby the Corporation agreed to provide services to the Commission with respect to operating the water treatment and distribution system as well as District Energy. The services include:

management, administrative services, construction operations, and maintenance services. The Corporation is responsible for providing all personnel required to operate the water system and District Energy. Pursuant to the terms of the WSOA and the associated Employee Arrangement Agreement, also dated November 6, 2012, the Commission transferred all nonunionized employees and all unionized employees of the Commission to the Corporation. The Commission is a local board of the City.

The Corporation provides billing, credit, financial, and customer service on behalf of the City in relation to waste water.

The Corporation also provides billing, credit, financial, customer service and other support services on behalf of ENWIN Energy Ltd. ( Energy ) in relation to sentinel lighting and street light maintenance.

The Corporation s arrangements with these affiliates are subject to the Ontario Energy Board s (OEB s) Affiliate Relationships Code, which is a code

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

prescribed by and issued pursuant to the Ontario Energy Board Act, 1998.

2. Basis of preparation:

(a) Statement of compliance:

The Corporation s financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 17, 2019.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments at fair value through profit or loss, are measured at fair value.

(ii) The accrued benefit related to the Corporation s unfunded defined benefit plan is actuarially determined and is measured at the present value of the defined benefit obligation.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand dollars.

(e) Use of estimates and judgements:

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

In particular, significant areas where upon estimation was required that have the most significant effect on the amounts recognized in these financial statements, include:

(i) Note 3(j) Deferred revenue: determination of the performance obligation for contributions from customers and the related amortization period;

(ii) Note 5 Trade accounts receivables: allowance for impairment. Unbilled revenue:

measurement of revenues not yet billed;

(iii) Note 7 Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment;

(iv) Note 14 Employee future benefits: measurement of the defined benefit obligation;

(v) Note 23 Financial instruments and risk management: valuation of financial instruments.

Information about critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements, include:

(i) the Corporation s determination that they are acting as a principal for electricity distribution and therefore have presented the electricity revenues on a gross basis.

(f) Rate regulation:

Effect of rate-setting regulations on the Corporation s activities and on these financial statements:

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

The Corporation is regulated by the Ontario Energy Board ( OEB ). In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The OEB s regulatory accounting treatments require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS and, as a result, these regulatory assets and liabilities have not been recorded in these IFRS financial statements.

The Ontario Energy Board Act, 1998 conferred on the OEB powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the distribution of electricity and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ( LDCs ), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct business, and filing and process requirements for rate setting purposes.

(i) Rate setting:

The electricity distribution rates and other regulated charges of the Corporation are determined by the OEB. This regulated rate-setting provides LDCs with the opportunity to recover the revenue requirement associated with owning and operating the LDC. The revenue requirement represents the forecasted prudent costs, including the cost of capital, that will be reasonably necessary for the LDC to invest in the electricity grid, operate the electricity grid, and serve customers in its licenced service area.

(ii) Rate Applications:

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**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

As set out in the OEB s Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, dated October 18, 2012, the
OEB performs its rate-setting function using a combination of incentive rate-setting
and cost of service rate-setting. Both rate-setting techniques are based on applications made by LDCs to the OEB. Provided an LDC meets OEB-specified performance parameters, the LDC can select from one of three rate-setting streams:
4th Generation Incentive Rate-setting, Custom Incentive Rate-setting, or Annual
Incentive Rate-setting Index. Each of these streams entails different rate-setting
schedules and substantive filing requirements. For all streams, the revenue requirement is established through a cost of service rate-setting application. The
selection of stream determines the number of years that cost of service rate-setting
application pertains to, and the number of years thereafter that the LDC is expected
to file incentive rate-setting applications.
Cost of service rate-setting applications recalculate the revenue requirement through
a comprehensive review of an LDC s forecasted costs for a prospective test year.
The OEB reviews the costs through a rigorous process and ultimately decides on the
recovery of allowed forecasted costs through rates. Incentive rate-setting

**T2 BAR CODE RETURN**

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**
**Tax Year Start: 2018-01-01**
**Tax Year End: 2018-12-31**

applications mechanistically adjust the revenue requirement using an
OEBprescribed
formula. That formula was established on November 21, 2013, in the
OEB s Report of the Board on Rate Setting Parameters and Benchmarking under
the
Renewed Regulatory Framework for Ontario s Electricity Distributors.
The OEB last used the cost of service technique to set the Corporation s
electricity
distribution rates for rates effective May 1, 2009. Since that time, the
Corporation s
rates have been mechanistically adjusted by the OEB through incentive rate-
setting.
The Corporation is on the Annual Incentive Rate-setting Index stream. The
Corporation may apply for rates using the cost of service technique at a time
of its
own choosing, provided that the Corporation continues to meet OEB-specified
performance parameters. If the Corporation does not continue to meet those
parameters, the OEB may mandate the Corporation to file a cost of service
ratesetting
application.
(iii) Conservation and Demand Management:
New LDC Licence Requirements Conservation and Demand Management ( CDM )
Targets:
On March 26, 2014, the Ontario Energy Board was directed to amend the licenses
of
electricity distributors to include requirements for achieving certain CDM
targets over
a six year period commencing January 1, 2015. These targets specify that

electricity

distributors will make CDM programs (Province-Wide Programs, Local Distributor

CDM Programs, or a combination of) available in their licensed service area to

all

customer segments; that CDM programs will be designated to achieve reductions

in electricity consumption; that each distributor shall meet its CDM

requirements by making Province-Wide CDM programs; and provide details and

results of Local

Distributor CDM Programs available to other Distributors upon request, while

having

regard to any confidentiality and privacy constraints.

On March 31, 2014, the Independent Electricity System Operator ( IESO ) was

directed to coordinate, support and fund the delivery of CDM programs through

electricity distributors to achieve a total of 7 TWh of reductions in

electricity

consumption over a six year period commencing January 1, 2015. The Corporation

s

contribution to the provincial target of 7 TWh is 151.3 GWh.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently to all

years presented in

these financial statements.

(a) Cash and cash equivalents:

Cash and cash equivalents consist of balances with banks and investments with

a maturity

of approximately three months or less at the date of purchase, unless they are

held for

investment rather than liquidity purposes, in which case they are classified

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

as an

investment.

(b) Financial instruments:

The Corporation adopted IFRS 9 Financial Instruments on January 1, 2018. There

were no

material adjustments required to the Corporation s financial results; however

the

Corporation has reclassified its financial instruments.

All financial assets and liabilities of the Corporation are classified into

one of the following

categories: amortized cost; fair value through other comprehensive income; or

fair value

through profit or loss.

The Corporation has classified its financial instruments as follows:

Cash and cash equivalents Amortized cost

Accounts receivable Amortized cost

Due from related parties Amortized cost

Accounts payable and accruals Amortized cost

Due to related parties Amortized cost

Long-term borrowings Amortized cost

Financial instruments are recognized initially at amortized cost plus any

directly attributable

transaction costs.

Subsequent to initial recognition, financial instruments classified as fair

value through profit

and loss are measured at fair value. The Corporation does not use derivative

instruments.

The Corporation derecognizes a financial asset when the contractual rights to

the cash
flows from the asset expire, or it transfers the rights to receive the
contractual cash flows in
a transaction in which substantially all of the risks and rewards of ownership
of the financial
asset are transferred.

The Corporation derecognizes a financial liability when its contractual
obligations are
discharged, cancelled or expire.

(c) Fair value:

Fair values are categorized into different levels in a fair value hierarchy
based on inputs
used in the valuation techniques as follows:

Level 1: unadjusted quoted prices in active markets for identical assets or
liabilities;

Level 2: inputs other than quoted prices included in Level 1 that are
observable for the
asset, either directly or indirectly; and

Level 3: inputs for assets and liabilities that are based on observable market
data.

(d) Inventory:

Inventory is measured at the lower of cost and net realizable value. The cost
of inventory
is determined on a weighted average basis. Net realizable value is determined
on a replacement cost basis.

(e) Property, plant and equipment:

(i) Recognition and measurement:

Items of property, plant and equipment are measured at cost less accumulated

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition

of the asset.

The cost of self-constructed assets includes the cost of materials and direct

labour, any

other costs directly attributable to bringing the asset to a working condition

for its

intended use, the costs of dismantling and removing the items and restoring

the site on

which they are located and capitalized borrowing costs. Borrowing costs on

qualifying

assets are capitalized as part of the cost of the asset and are based on the

Corporation s average cost of borrowing.

When parts of an item of property, plant and equipment have different useful

lives, they

are accounted for as separate items (major components) of property, plant and

equipment.

(ii) Subsequent costs:

The cost of replacing part of an item of property, plant and equipment is

recognized in

the carrying amount of the item if it is probable that the future economic

benefits

embodied within the part will flow to the Corporation and its cost can be

measured

reliably. The carrying amount of the replaced part is derecognized. The costs

of the

day-to-day servicing of property, plant and equipment are recognized in the

statement

**T2 BAR CODE RETURN**

**Name: Enwin Utilities Ltd.**

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**Tax Year Start: 2018-01-01**
**Tax Year End: 2018-12-31**

of income as incurred.

(iii) Depreciation:

Depreciation is recognized in the statement of income on a straight-line basis
over the
estimated useful life of each part or component of an item of property, plant
and
equipment. Land is not depreciated.

The estimated useful lives for the current and comparative years are as
follows:

Buildings 10 50 years

Distribution and metering equipment 8 80 years

Other assets 5 20 years

Gains and losses on disposal of an item of property, plant and equipment are
determined by comparing the proceeds from disposal with the carrying amount of
property, plant and equipment and are recognized within other income in the
statement
of income.

Depreciation methods, useful lives and residual values are reviewed at each
reporting
date.

(f) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including
software that is not integral to the functionality of equipment purchased,
which have
finite useful lives, are measured at cost less accumulated amortization and
accumulated impairment losses.

(ii) Amortization:

Amortization is recognized in the statement of income on a straight-line basis
over the
estimated useful lives of the intangible assets, from the date that they are
available for
use. The estimated useful lives for the current and comparative years are:
Computer software 5 - 10 years
Amortization methods and useful lives of all intangible assets are reviewed at
each reporting date.
(g) Work in progress:
Work in progress is recorded at cost, with cost being determined based on
material
purchased services, internal labour and overhead, as applicable.
(h) Impairment:
(i) Financial assets:
A financial asset is assessed at each reporting date to determine whether
there is any
objective evidence that it is impaired. A financial asset is considered to be
impaired if
objective evidence indicates that one or more events have had a negative
effect on the
estimated future cash flows of that asset.
A loss allowance for expected credit losses on financial assets measured at
amortized
cost is recognized at the reporting date. The loss allowance is measured at an
amount
equal to the lifetime expected credit losses for the asset.
All impairment losses are recognized in the statement of income. An impairment
loss

is reversed if the reversal can be related objectively to an event occurring
after the
impairment loss was recognized. For financial assets measured at amortized
cost, the
reversal is recognized in the statement of income.
(ii) Non-financial assets:
The carrying amounts of the Corporation's non-financial assets, other than
inventory,
work-in-progress and deferred tax assets, are reviewed at each reporting date
to
determine whether there is any indication of impairment. If any such
indication exists,
then the asset's recoverable amount is estimated.
Impairment losses recognized in prior periods are assessed at each reporting
date for
any indications that the loss has decreased or no longer exists. An impairment
loss is
reversed if there has been a change in the estimates used to determine the
recoverable amount. An impairment loss is reversed only to the extent that the
asset s
carrying amount does not exceed the carrying amount that would have been
determined, net of depreciation or amortization, if no impairment loss had
been
recognized.
For the purpose of impairment testing, assets are grouped together into the
smallest
group of assets that generates cash inflows from continuing use that are
largely

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independent of the cash inflows of other assets or groups of assets (the
"cashgenerating
unit"). The recoverable amount of an asset or cash-generating unit is the
greater of its value in use and its fair value less costs to sell. In
assessing value in use,
the estimated future cash flows are discounted to their present value using a
pre-tax
discount rate that reflects current market assessments of the time value of
money and
the risks specific to the asset.
An impairment loss is recognized if the carrying amount of an asset or its
cashgenerating
unit exceeds its estimated recoverable amount. Impairment losses are
recognized in the statement of income and are allocated to reduce the carrying
amount
of the assets in the cash-generating unit on a pro-rata basis.
(i) Employee future benefits:
(i) Pension plan:
The Corporation provides a pension plan for all its full-time employees
through Ontario
Municipal Employees Retirement System ( OMERS ). OMERS is a multi-employer,
contributory, defined benefit pension plan established in 1962 by the Province
of
Ontario for employees of municipalities, local boards and school boards in
Ontario.
Both participating employers and employees are required to make plan
contributions
based on participating employees' contributory earnings.

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OMERS is a defined benefit plan. However, as OMERS does not segregate its pension assets and liabilities information by individual employer, there is not sufficient information to enable the Corporation to account for the plan as a defined benefit plan.

The plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in income when they are due. At December 31, 2018, the OMERS plan is in a deficit position.

(ii) Post-employment benefits, other than pension:

The Corporation pays certain health, dental and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Corporation is the legal sponsor of the plan. There is a policy in place to allocate the net defined benefit cost to the entities participating in the group plan. The allocation is based on the obligation attributable to the plan participants. The Corporation has reflected its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these financial statements.

The Corporation accrues the cost of these employee future benefits over the periods in

which the employees earn the benefits. The accrued benefit obligations and the current
service costs are actuarially determined by applying the projected unit credit method
and reflect management s best estimate of certain underlying assumptions. The current service cost for a period is equal to the actuarial present value of benefits
attributed to that period in which employees rendered their services.
Remeasurements of the net defined benefit liability, which comprise actuarial gains and
losses, are recognized immediately in other comprehensive income. The Corporation
determines the net interest expense on the net defined benefit liability for the period by
applying the discount rate used to measure the defined benefit liability at the beginning
of the annual period, taking into account any changes in the net benefit liability during
the period as a result of benefit payments. Net interest expense and other expenses
related to defined benefit plans are recognized in the statement of income.
Gains and losses on account of curtailment or settlement of these employee future
benefits are recognized immediately in income.
In accordance with the WSOA and Employee Arrangement Agreement between the Commission and the Corporation, the Plan was amended such that all active Commission management and union employees were included as part of the Plan, and

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have their coverage sponsored by the Corporation. A date of December 31, 2012 was
assumed by the actuary to reflect this event in the Plan.

(j) Deferred revenue:

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 Revenue from Contracts with Customers.

The contributions are received to obtain a connection to the distribution system in order
to receive ongoing access to electricity. The Corporation has concluded that the
performance obligation is the supply of electricity over the life of the relationship with
the customer which is satisfied over time as the customer receives and consumes the
electricity. Revenue is recognized on a straight-line basis over the useful life of the
related asset.

(k) Customer deposits:

Customer deposits include cash collections from customers, which are applied against any
unpaid portion of individual customer accounts. Effective January 1, 2011, the OEB
required that a customer s deposit be applied to the customer s account prior to the
severance process commencing. OEB rules also specify that customer deposits in excess

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of unpaid account balances must be refunded to customers. Customer deposits
are also
refundable at the Corporation s discretion when a customer demonstrates an
acceptable
level of credit risk. The Corporation only retains commercial deposits.
Customer deposits
also include monies received from developers and distribution customers for
services that
are recorded as construction in progress and, once the assets are put into
service, will be
accounted for through a capital contribution.
(l) Revenue recognition:
IFRS 15 Revenue from contracts with customers became effective January 1,
2018. This
standard established a comprehensive framework for determining whether, how
much and
when revenue is recognized. Based on the new revenue recognition criteria,
there was no
material adjustment to the Corporation s revenue.
The performance obligations for the sale and distribution of electricity are
recognized over
time using an output method to measure the satisfaction of the performance
obligation. The
value of the electricity services transferred to the customer is determined on
the basis of
cyclical meter readings plus estimated customer usage since the last meter
reading date to
the end of the year and represents the amount that the Corporation has the

right to bill.
Revenue includes the cost of electricity supplied, distribution, and any other
regulatory
charges. The related cost of power is recorded on the basis of power used.
For customer billings related to electricity generated by third parties and
the related costs of
providing electricity service, such as transmission services and other
services provided by
third parties, the Corporation has determined that it is acting as a principal
for these
electricity charges and, therefore, has presented electricity revenue on a
gross basis.
Revenue for the Corporation is recognized when the Corporation satisfies the
performance
obligations within the contract(s) for conditions of service, which is when
the distribution and
delivery of electricity is achieved or specific services are performed.
Revenue includes an estimate of unbilled revenue. Unbilled revenue represents
an
estimate of electricity consumed by customers since the date of each customer
s last meter
reading. Actual electricity usage could differ from those estimates.
Revenue is measured at the fair value of the consideration received or
receivable, net of
any taxes which may be applicable.
Other income for work orders is recorded on a net basis as the Corporation is
acting as an
agent for this revenue stream. All other amounts in other income are recorded

on a gross

basis and are recognized when services are rendered.

(m) Finance costs:

Finance costs comprise interest expense on borrowings and unwinding of the

discount rate

on provisions.

(n) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense

is

recognized in the statement of income except to the extent that it relates to

items

recognized directly in equity, in which case, it is recognized in equity.

Under the Electricity Act 1998, the Corporation makes payments in lieu of

corporate taxes

to Ontario Electricity Financial Corporation ( OEFC ). These payments are

calculated in

accordance with the rules for computing taxable income and taxable capital and

other

relevant amounts contained in the Income Tax Act (Canada) and the Corporation

Tax Act

(Ontario) as modified by the Electricity Act, 1998 and related regulations.

Payments in lieu

of taxes ( PILS ) are referred to as income taxes.

Current tax is the expected PILs payable on the taxable income for the year,

using tax

rates enacted or substantively enacted at the reporting date and any

adjustment to tax

payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the statement of income in the year that includes the date of enactment or substantive enactment.

(o) Set-off and reporting on a net basis:

Assets and liabilities and income and expenses are not offset and reported on a net basis unless required or permitted by IFRS. For financial assets and financial liabilities, offsetting is permitted when, and only when, the Corporation has a legally enforceable right to set-off and intends either to settle on a net basis, or to realize the asset and settle the liability simultaneously.

(p) New standards and interpretations not yet adopted:

The following standards, which are not yet effective for the year ended December 31, 2018, have not been applied in preparing these financial statements.

IFRS 16 Leases

IFRS 16, issued on January 13, 2016, introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by lessors. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided.

IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019.

IFRS 16 will replace IAS 17. The Corporation has assessed the potential impacts on its financial statements and determined that IFRS 16 will not impact the Corporation in 2019.

IFRIC 23 Uncertainty over Income Tax Treatments

IFRIC 23 intends to clarify how to apply the recognition and measurement requirements in IAS 12 Income Taxes. The IFRIC is effective for annual periods beginning on or after

January 1, 2019.

4. Cash and cash equivalents:

| | 2018 | 2017 |
|---|---|---|
| Cash and cash equivalents | $ 34,928 | $ 26,205 |
| Cash and cash equivalents | $ 34,928 | $ 26,205 |

The Corporation and WCUL have an agreement with a Canadian chartered bank for an operating line of credit in the amount of $75,000 (2017 - $75,000) bearing interest at prime minus 0.25%. The line of credit restricts the availability of the Corporation to lien assets. As of December 31, 2018, the outstanding balance in the line of credit was $nil (2017 - $nil).

5. Accounts receivable:

| | 2018 | 2017 |
|---|---|---|
| Trade receivables | $ 23,722 | $ 21,169 |
| Unbilled revenue | 25,888 | 26,641 |
| Allowance for doubtful accounts | (985) | (1,038) |
| Accounts receivable | $ 48,625 | $ 46,772 |

6. Inventory:

Inventory consists of parts and supplies acquired for capital, internal construction, maintenance or recoverable work.

The amount of inventory consumed by the Corporation during 2018 was $5,625 (2017 - $5,164).

7. Property, plant and equipment:

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(a) Cost:

Land Distribution Construction

and and metering Other -inbuildings

equipment assets progress Total

Balance at January 1, 2017 $ 20,739 $ 222,623 $ 18,414 $ 3,380 $ 265,156

Additions 364 13,019 1,405 (368) 14,420

Disposals/retirements (22) (600) - - (622)

Balance at December 31, 2017 $ 21,081 $ 235,042 $ 19,819 $ 3,012 $ 278,954

Balance at January 1, 2018 $ 21,081 $ 235,042 $ 19,819 $ 3,012 $ 278,954

Additions 229 15,523 4,473 (1,121) 19,104

Disposals/retirements (13) (823) - - (836)

Balance at December 31, 2018 $ 21,297 $ 249,742 $ 24,292 $ 1,891 $ 297,222

(b) Accumulated depreciation:

Land Distribution Construction

and and metering Other -inbuildings

equipment assets progress Total

Balance at January 1, 2017 $ 5,211 $ 33,292 $10,433 $ - $ 48,936

Depreciation charge for the year 918 6,659 1,664 - 9,241

Disposals/retirements - (157) - - (157)

Balance at December 31, 2017 $ 6,129 $ 39,794 $ 12,097 $ - $ 58,020

Balance at January 1, 2018 $ 6,129 $ 39,794 $12,097 $ - $ 58,020

Depreciation charge for the year 931 6,896 1,918 - 9,745

Disposals/retirements/transfers (2) (207) 94 - (115)

Balance at December 31, 2018 $ 7,058 $ 46,483 $ 14,109 $ - $ 67,650

(c) Carrying amounts:

Land Distribution Construction

and and metering Other -inbuildings

equipment assets progress Total

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December 31, 2017 $ 14,952 $ 195,248 $ 7,722 $ 3,012 $ 220,934

December 31, 2018 $ 14,239 $ 203,259 $10,183 $ 1,891 $ 229,572

8. Intangible assets

(a) Cost or deemed cost:

Computer

software

Balance at January 1, 2017 $ 28,327

Additions 1,162

Balance at December 31, 2017 $ 29,489

Balance at January 1, 2018 $ 29,489

Additions 488

Balance at December 31, 2018 $ 29,977

(b) Accumulated amortization:

Computer

software

Balance at January 1, 2017 $ 16,571

Amortization charge for the year 4,220

Balance at December 31, 2017 $ 20,791

Balance at January 1, 2018 $ 20,791

Amortization charge for the year 4,264

Balance at December 31, 2018 $ 25,055

(c) Carrying amounts:

Computer

software

December 31, 2017 $ 8,698

December 31, 2018 $ 4,922

9. Investment:

In 2014, a sinking fund was established with the intent to ensure sufficient funds are available

to settle the long-term borrowings issued November 6, 2012, with a maturity

date of November

6, 2042, in the amount of $51,000. Effective December 31, 2018, the sinking

fund balance of

$7,819 was transferred to WCUL as partial consideration against a promissory

note. See Note

17 for additional details.

The investment was recorded at market value and was invested in fixed income

and equity

markets as established by the Corporation s investment policy.

Fixed

income Equity Total

December 31, 2017:

Investment $ 5,023 $ 1,507 $ 6,530

5,023 1,507 6,530

December 31, 2018:

Investment - - -

$ - $ - $ -

10. Accounts payable and accruals:

2018 2017

Trade payables $ 22,019 $ 22,630

Accrued expenses 3,751 7,800

$ 25,770 $ 30,430

Information about the Corporation s exposure to currency and liquidity risk is

included in Note

23.

11. Customer deposits:

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Customer deposits represent cash deposits from electricity distribution

commercial customers

and construction deposits.

Customer deposits comprise:

2018 2017

Customer deposits $ 5,114 $ 6,770

Construction deposits 1,724 1,875

6,838 8,645

Less: current portion 919 1,211

$ 5,919 $ 7,434

12. Deferred revenue customer contributions:

Deferred revenue relates to the capital contributions received from customers

and others. The

amount of deferred revenue received from customers is $14,447 (2017 -

$12,681). Deferred

revenue is recognized as revenue on a straight-line basis over the life of the

asset for which the

contribution was received.

13. Long-term borrowings:

Long-term borrowings comprise:

2018 2017

Promissory note payable $ 51,000 $ 51,000

Less: debt issuance costs (530) (543)

$ 50,470 $ 50,457

The promissory note payable is due to WCUL, the parent company of the

Corporation. On

November 12, 2012 WCUL issued a $103,000 debenture from which proceeds of

$51,000

were advanced to the Corporation under this unsecured promissory note. The
note has terms
consistent with the WCUL debenture including a maturity date of November 6,
2042, and bears
interest at a rate of 4.134% per annum. Interest is payable in equal semi-
annual instalments of
$1,054, in arrears, on May 6 and November 6 each year commencing May 6, 2013.
In order to
put the debt in place, the Corporation incurred debt issuance costs in the
amount of $601.
The Corporation incurred interest expense in respect of the promissory note
payable of $2,108
(2017 - $2,108), which is included in finance expense on the statement of
income.
14. Employee future benefits:
The Corporation pays certain health, dental and life insurance benefits on
behalf of its retired
employees. Significant assumptions underlying the actuarial valuation include
management s
best estimate of the interest (discount) rate, mortality decrement, the
average retirement age of
employees, employee turnover and expected health and dental care costs.
The plan was amended such that all active Commission management and union
employees
covered under the Commission collective agreement from July 1, 2012, would be
included as
part of the Plan and have their coverage sponsored by the Corporation. The
December 31,

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2012, date was chosen to reflect this event in the Plan. Reference note 1 for
further
information.
The Corporation measures its accrued benefit liability for accounting purposes
as at December
31 each year. A valuation date of December 31, 2016, with extrapolation to
December 31,
2018, has been used to calculate the current obligation.
The Corporation s employee future benefit liability consists of the following:
2018 2017
Defined benefit liability $ 64,397 $ 68,392
Defined benefit liability, end of year $ 64,397 $ 68,392
Information about the Corporation s unfunded defined benefit plan is as
follows:
Changes in the present value of the defined benefit obligation:
2018 2017
Defined benefit liability, beginning of year $ 68,392 $ 59,475
Current service cost 2,528 2,358
Interest cost 2,297 2,289
Actuarial (gain)/loss on liability recognized in other
comprehensive income (7,283) 5,758
Benefits paid for the year (1,537) (1,488)
Defined benefit liability, end of year $ 64,397 $ 68,392
Components of net benefit expense recognized are as follows:
2018 2017
Current service cost $ 2,528 $ 2,358
Interest cost 2,297 2,289
Net benefit expense recognized $ 4,825 $ 4,647

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Net benefit expense for the year is recognized as administrative expense on
the statement of
income.
The main actuarial assumptions underlying the valuation are as follows:
(a) Health care cost trend rates:
The health care cost trend for prescription drugs is estimated to increase at
6.5% in 2018
grading down to 4.5% by 2027. Other health expenses are estimated to increase
at 5.83%
grading down to 4.5% by 2027. Dental expenses are estimated to increase at
4.0% per
year.
(b) Financial instruments:
The liabilities at the period end and the present value of future liabilities
were determined
using a discount rate of 4.0% (2017 - 3.4%) representing an estimate of the
yield on high
quality corporate bonds as at the valuation date.
(c) Mortality decrement:
The rates applicable to public sector retirees in the 2014 Canadian Pensioners
Mortality
table ( CPM 2014 ) produced by the Canadian Institute of Actuaries ( CIA )
were used as
the basis of these assumptions.
A 1% or one year change in actuarial assumptions, assuming all other factors
remain constant,
has the following impact on the defined benefit liability carrying amount:
December 31, 2018 December 31, 2017

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Increase Decrease Increase Decrease

Health care trend rate (1% change) $ 12,236 $ (9,605) $ 12,993 $ (10,199)

Discount rate (1% change) (10,312) 13,390 (10,950) 14,219

Mortality (1 year) 2,817 (2,721) 2,992 (2,890)

15. Pension plan:

The Corporation participates in the Ontario Municipal Employees Retirement

Fund ( OMERS ),

a multi-employer plan, on behalf of its employees. The plan has been accounted

for as a

defined contribution plan. Contributions during the year were 9.0% (2017 -

9.0%) for employee

earnings below the year s maximum pensionable earnings and 14.6% (2017 -

14.6%)

thereafter. During 2018, the Corporation expensed contributions totalling

$2,937 (2017 -

$2,887) made to OMERS in respect of the employer s required contributions to

the plan.

Estimated contributions for 2019 are $3,030.

16. Income taxes (provision for payment in lieu of corporate taxes):

2018 2017

Current tax expense:

Current year $ 4,126 $ 3,798

Adjustments for prior years (2,838) (58)

Deferred tax expense:

Origination and reversal of temporary differences 3,498 (2,343)

Adjustments for prior years - 478

Tax related to remeasurement of employee future benefits (1,930) 1,526

Total income taxes expense $ 2,856 $ 3,401

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The provision for income taxes varies from amounts which would be computed by

applying the

Corporation s combined statutory income tax rate as follows:

2018 2017

Basic rate applied to total comprehensive income

before income tax 26.50% 26.50%

Change in income tax resulting from:

Items not deductible for tax purposes and other (0.54%) 4.49%

Effective rate applied to comprehensive

income before income taxes 25.96% 30.99%

The components of the deferred income tax assets and liabilities are

summarized as follows:

2018 2017

Deferred tax assets:

Employee benefits $ 10,747 $ 11,589

Regulatory assets 428 -

Other 250 309

Deferred tax liabilities:

Property, plant and equipment 4,824 1,034

Regulatory liabilities - 748

Other 100 118

Net deferred income tax asset $ 6,501 $ 9,998

At December 31, 2018, a deferred tax asset of $6,501 (2017 - $9,998) has been

recorded. The

utilization of this tax asset is dependent on future taxable income in excess

of income arising

from the reversal of existing taxable temporary differences. The Corporation

believes that this

asset should be recognized as it will be recovered through future rates.

17. Share capital

On November 13, 2018, the Corporation authorized a reduction in the stated

capital of its

outstanding common shares of $31,000. Proceeds from the stated capital

reduction were

loaned back to the Corporation. See note 22 for additional information.

2018 2017

Authorized:

Unlimited common shares

Issued:

11,000 common shares $ 31,008 $ 62,008

18. Distribution revenue:

The Corporation generates revenue primarily from the sale and distribution of

electricity to its

customers. Other revenue consists of services provided to related parties and

other income.

Additional information is provided in Note 19 with components of other income.

In the following table, distribution revenue is disaggregated by type of

customer:

2018 2017

Residential $ 25,910 $ 24,490

General service small distribution 19,525 19,025

General Service large distribution 4,638 4,565

Street lighting distribution 1,793 1,715

Total distribution revenue $ 51,866 $ 49,795

19. Other income:

Other income comprises:

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2018 2017

Change in occupancy $ 372 $ 403

Late payment and collection charges 378 366

Other operating revenues 1,221 1,462

(Loss)/gain on disposal of property, plant and equipment (361) 66

Pole rental 775 618

Sale of scrap 116 82

Sewer surcharge billing and collecting 2,876 2,891

Total other income $ 5,377 $ 5,888

20. Employee benefits:

Note 2018 2017

Salaries and benefits $ 24,893 $ 23,976

Contributions to multi-employer plan 15 2,937 2,887

Expenses related to defined benefit plans 14 4,825 4,647

$ 32,655 $ 31,510

21. Finance expense (income):

2018 2017

Finance income:

Interest income on bank balances $ (556) $ (259)

Income on investment (89) (197)

Interest income on PILs refund (6) -

(651) (456)

Finance expense:

Interest expense on long-term borrowings 2,108 2,108

Interest expense on related party debt 233 207

Interest expense on customer deposits 103 60

Discount on long-term borrowings 13 12

2,457 2,387

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Net finance expense $ 1,806 $ 1,931

22. Related party transactions:

(a) Parent and ultimate controlling party:

The parent is WCUL. The parent of WCUL and the ultimate controlling party of

the

Corporation is the Corporation of the City of Windsor ( City ). WCUL and the

City produce

financial statements that are available for public use.

(b) Key management personnel:

The key management personnel of the Corporation has been defined as members of

its

board of directors and executive management team members.

Key management compensation:

2018 2017

Salaries and other short-term benefits $ 1,050 $ 1,015

Post-employment benefits 14 12

$ 1,064 $ 1,027

(c) Transactions with parent and ultimate controlling party:

The Corporation provides waste water billing and related services for the

City, for which the

Corporation charges a fee. The total amount charged to the City for the year

ended

December 31, 2018, was $2,876 (2017 - $2,891). The fee charged for the waste

water

billing and related services is recognized as other income from operations on

the statement

of income.

The Corporation collects and remits the waste water billing amounts on behalf of the City.

The total amount owing to the City at December 31, 2018, relating to waste

water billing

was $5,649 (2017 - $5,219).

(d) Transactions with entities under common control:

On November 6, 2012, the Corporation and the Commission entered into a WSOA,

whereby the Corporation agreed to provide services to the Commission with

respect to the

operation of the Commission s water system and District Energy. The total

amount

charged to the Commission for the year ended December 31, 2018, was $20,004

(2017

$19,336).

Under a Management Services Agreement effective January 1, 2000, the

Corporation

provides certain finance, administration, human resources, management and

other support

services to its affiliate, Energy. The total amount charged to Energy for the

year ended

December 31, 2018, was $138 (2017 - $168).

(e) Amounts due from (to) related parties:

The current amounts due from related parties consist of:

2018 2017

Due from companies under common control:

Due from Windsor Utilities Commission $ 2,308 $ 3,145

Due from ENWIN Energy Ltd. - 115

Due from Windsor Canada Utilities Ltd. 18 -

$ 2,326 $ 3,260

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The amounts due from the Commission and WCUL are due on demand and are

noninterest

bearing. These amounts have no specified repayment terms.

The non-current amounts due from related parties consist of:

2018 2017

Due from Windsor Utilities Commission $ 2,877 $ 3,699

Less: current portion 822 822

$ 2,055 $ 2,877

This long term receivable resulted from the Employee Arrangement Agreement and

is

amortized over the estimated average remaining service life at the time of the

agreement

which was 9.5 years, payable each November.

(e) Amounts due from (to) related parties (continued):

The current amounts due to related parties consist of:

2018 2017

Due to companies under common control:

Due to ENWIN Energy Ltd. $ 11 $ -

Note payable to Windsor Canada Utilities Ltd. - 6,873

Due to ultimate parent:

Due to the Corporation of the City of Windsor 5,649 5,219

$ 5,660 $ 12,092

The non-current amounts due to related parties consist of:

2018 2017

Due to companies under common control:

Promissory note payable to Windsor Canada Utilities Ltd.$ 29,032 $ -

$ 29,032 $ -

The promissory note payable to WCUL is unsecured, due on the earlier of 375

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days from

the date of demand or December 31, 2028. This note has an initial interest

rate of 4.16%,

but is adjustable to the OEB s deemed long term debt rate that is in effect

for ENWIN. This

note has no specified repayment terms.

The amounts due to Energy and the City are unsecured and are non-interest

bearing.

23. Financial instruments and risk management:

The carrying values of cash and cash equivalents, accounts receivable, amounts

due from (to)

related parties, accounts payable and accruals approximate fair values because

of the short

maturity of these instruments.

The following table illustrates the classification of the Corporation s

financial instruments using

the fair value hierarchy as at December 31:

2018 2017

Assets Level 1 Level 2 Total Level 1 Level 2 Total

Investment   fixed income $ - $ - $ - $ - $ 5,023 $ 5,023

Investment   equity - - - 1,507 - 1,507

$ - $ - $ - $ 1,507 $ 5,023 $ 6,530

The investment was transferred to WCUL during the year and, therefore, the

fair value of the

investment is $nil (2017 - $6,530). The fair value is calculated based on the

quoted market

price in the active markets.

The Corporation s activities provide for a variety of financial risks,

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

particularly credit risk, market

risk and liquidity risk.

(i) Credit risk:

The aging of accounts receivables at the reporting date was:

2018 2017

Not past due $ 43,544 $ 42,432

Past due 0   30 days 2,383 2,182

Past due 31   60 days 893 593

Greater than 60 days 1,805 1,565

$ 48,625 $ 46,772

Financial assets carry credit risk that a counter-party will fail to discharge

an obligation

which would result in a financial loss. Financial assets held by the

Corporation, such as

accounts receivable, expose it to credit risk. The Corporation earns its

revenue from a

broad base of customers located in the City of Windsor. No single customer

accounts for

greater than 8.1% (2017   9%) of revenues.

The carrying amount of accounts receivable is reduced through the use of an

allowance for

impairment and the amount of the related impairment loss is recognized in the

statement of

income. Subsequent recoveries of receivables previously provisioned are

credited to the

statement of income. The balance of the allowance for impairment at December

31, 2018,

is $985 (2017 - $1,038).

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

A continuity of the allowance for doubtful accounts is as follows:

2018 2017

Balance, beginning of year $ 1,038 $ 1,251

Accounts receivable balances written off (385) (590)

Change in provisions for doubtful accounts 332 377

Balance, end of year $ 985 $ 1,038

The Corporation s credit risk associated with accounts receivable is primarily
related to
payments from customers. At December 31, 2018, approximately $1,805 (2017 -
$1,565)
is considered 60 days past due. Credit risk is managed through collection of
security
deposits from customers in accordance with OEB regulation. As of December 31,
2018,
the Corporation holds security deposits in the amount of $5,114 (2017 -
$6,770).

(ii) Liquidity risk:

Liquidity risk is the risk that the Corporation will not be able to meet its
obligations
associated with financial liabilities. The Corporation monitors its liquidity
risk to ensure
access to sufficient funds to meet operational and investing requirements. The
Corporation s objective is to ensure that sufficient liquidity is on hand to
meet obligations as
they fall due while minimizing interest expense. The Corporation has access to
a line of
credit and monitors cash balances to ensure that sufficient levels of
liquidity are on hand to

meet financial commitments as they come due.

The following are the contractual maturities of financial liabilities:

6 More Other

Months 6-12 1-2 than 2 non cash Carrying

December 31, 2018 or less Months years years adjustments amount

Accounts payable

and accruals $ 25,658 $ 112 $ - $ - $ - $ 25,770

Due to related parties 5,660 - - 29,032 - 34,692

Customer deposits 460 459 919 5,000 - 6,838

Long-term borrowings - - - 51,000 (530) 50,470

$ 31,778 $ 571 $ 919 $ 85,032 $ (530) $117,770

6 More Other

Months 6-12 1-2 than 2 non cash Carrying

December 31, 2017 or less Months years years adjustments amount

Accounts payable

and accruals $ 30,287 $ 143 $ - $ - $ - $ 30,430

Due to related parties 5,719 500 1,000 4,873 - 12,092

Customer deposits 601 601 1,211 6,232 - 8,645

Long-term borrowings - - - 51,000 (543) 50,457

$ 36,607 $ 1,244 $ 2,211 $ 62,105 $ (543) $101,624

(iii) Market risk:

Market risks primarily refer to the risk of loss that results from changes in

commodity

prices, foreign exchange rates, and interest rates. The Corporation is exposed

to market

risks within the investment portfolio. A portion of the portfolio is invested

in equities which

are subject to market forces. For sensitivity purposes, a 1% change in

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**
**Tax Year Start: 2018-01-01**
**Tax Year End: 2018-12-31**

equities would result
in a change of $nil (2017 - $15) on the balance sheet and the statement of
income.
(iv) Capital disclosures:
The main objectives of the Corporation when managing capital are to ensure
ongoing
access to funding to maintain and improve the electricity distribution system,
compliance
with covenants related to its credit facilities, prudent management of its
capital structure
with regard for recoveries of financing charges permitted by the OEB on its
regulated
electricity distribution business, and to deliver the appropriate financial
returns.
The Corporation s definition of capital includes shareholder s equity and long
-term debt. As
at December 31, 2018, shareholder s equity amounts to $127,518 (2017 -
$148,009) and
long-term debt amounts to $50,470 (2017 - $50,457).
Through rate-setting, the OEB determines the prudent costs of capital that are
recoverable
by the Corporation in relation to the distribution business. These costs of
capital are the
interest on debt and return on equity. The OEB permits recovery on the basis
of a deemed
capital structure of 60% debt and 40% equity. The actual capital structure for
the
Corporation may differ from the OEB deemed structure.

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

The Corporation has customary covenants typically associated with long-term debt. The Corporation is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

(v) Interest rate risk:

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Corporation is subject to variable interest rate cash flow risk with respect to its investments. The Corporation has addressed this risk by entering into fixed interest rates on invested funds and debts.

(vi) Currency risk:

Currency risk is the risk that the fair value or future cash flow of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation is exposed to currency risk through its foreign currency denominated bank and investment accounts. A weakening or strengthening of the Canadian dollar can affect the cash flows. This risk is monitored by investment managers and the exposure is limited to these accounts. For sensitivity purposes, a 1% change in the Canadian dollar would result in a change of $nil (2017 - $9) on the balance sheet and statement of income.

24. Commitments and contingencies:

Contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General liability insurance

The Corporation is a member of the Municipal Electrical Reciprocal Insurance Exchange ( MEARIE ), a self-insurance plan that pools the liability risks of all the Municipal Electric Utilities in Ontario. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE for the years in which the Corporation was a member. To December 31, 2018, the Corporation has not been made aware of any additional assessments that have not been accrued.

25. Regulatory balances:

Under IFRS, there is no recognition of regulatory assets or liabilities, and therefore, the impacts of these transactions are reflected on the statement of income, as applicable. As a result of not

# T2 BAR CODE RETURN

**Name: Enwin Utilities Ltd.**

**BN: 86712 0586 RC 0002**

**Tax Year Start: 2018-01-01**

**Tax Year End: 2018-12-31**

recognizing rate-regulated assets and liabilities, the effect was to increase

(decrease)

comprehensive income as follows:

2018 2017

Gross income:

Retail settlement variance $ (19) $ 1,144

Expenses:

Retail cost variance 164 (142)

Property, plant and equipment (Mist Meters) (203) 96

PILS (1,170) -

Future PILS (1,568) 339

Regulatory adjustment for IFRS conversion 2,374 2,280

Disposition and recovery of regulatory balances (4,413) (3,445)

Interest expense (net of interest revenue) (52) 61

Other 89 -

Change in comprehensive income (loss) $ (4,798) $ 333

26. Comparative figures:

Certain reclassifications have been made to the prior year s financial

statements to enhance

comparability with the current year s financial statements. As a result,

certain line items have

been amended in the balance sheet, statement of income and other comprehensive

income,

statement of changes in equity and statement of cash flow and the related

notes to the financial

statements. There was no impact on current or prior year s net income.

Comparative figures

have been adjusted to conform to the current year s presentation.

**SCHEDULE 100**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

## Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1000 | 34,928,348 | 1062 | 48,624,811 | 1064 | 2,326,085 |
| 1120 | 3,749,215 | 1484 | 767,068 | 1599 | 90,395,527 |
| 1600 | 1,362,556 | 1680 | 19,934,759 | 1681 | -7,058,380 |
| 1742 | 4,503,897 | 1743 | -1,114,259 | 1774 | 5,459,528 |
| 1775 | -3,983,888 | 1785 | 13,637,081 | 1786 | -8,489,157 |
| 1787 | 692,354 | 1788 | -521,285 | 1900 | 249,741,960 |
| 1901 | -46,482,660 | 1920 | 1,889,478 | 2008 | 297,221,613 |
| 2009 | -67,649,629 | 2010 | 29,977,339 | 2011 | -25,055,065 |
| 2178 | 29,977,339 | 2179 | -25,055,065 | 2240 | 2,054,765 |
| 2420 | 297,257 | 2421 | 6,500,609 | 2589 | 8,852,631 |
| 2599 | 333,742,416 | | | | |

## Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 25,770,767 | 2680 | 857,664 | 2770 | 8,751,623 |
| 2860 | 5,659,928 | 2960 | 918,688 | 3139 | 41,958,670 |
| 3140 | 5,919,053 | 3210 | 50,469,707 | 3220 | 14,447,081 |
| 3260 | 29,032,294 | 3320 | 64,397,300 | 3450 | 164,265,435 |
| 3499 | 206,224,105 | | | | |

## Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 31,008,479 | 3540 | 516,527 | 3580 | -2,683,128 |
| 3600 | 98,676,433 | 3620 | 127,518,311 | 3640 | 333,742,416 |

## Retained earnings – lines 3660 to 3849

| | | | | | |
|---|---|---|---|---|---|
| 3660 | 93,520,809 | 3680 | 8,155,624 | 3700 | -3,000,000 |
| 3849 | 98,676,433 | | | | |

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

**SCHEDULE 125**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

### Description

Sequence number . . . . . . . 0003 01

### Other comprehensive income – lines 7000 to 7020

| | | | |
|---|---|---|---|
| 7000 | 7,282,800 | 7010 | 1,929,942 |

### Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 301,297,635 | 8089 | 301,297,635 | 8100 | 651,388 |
| 8210 | -361,159 | 8230 | 5,384,123 | 8233 | 20,003,563 |
| 8241 | 138,183 | 8299 | 327,113,733 | | |

### Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8320 | 252,700,408 | 8518 | 252,700,408 | 8519 | 48,597,227 |

### Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8523 | 67,749 | 8620 | 4,825,200 | 8670 | 13,655,154 |
| 8710 | 2,650,951 | 8960 | 4,337,455 | 9270 | 37,864,828 |
| 9367 | 63,401,337 | 9368 | 316,101,745 | 9369 | 11,011,988 |

### Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| 9970 | 11,011,988 | 9990 | 1,288,306 | 9995 | 1,568,058 |
| 9998 | 5,352,858 | 9999 | 13,508,482 | | |

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

# Net Income (Loss) for Income Tax Purposes

**Schedule 1**

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 | | | | 13,508,482 | A |
| **Add:** | | | | | |
| Provision for income taxes – current | 101 | 1,288,306 | | | |
| Provision for income taxes – deferred | 102 | 1,568,058 | | | |
| Amortization of tangible assets | 104 | 13,655,154 | | | |
| Loss on disposal of assets | 111 | 361,159 | | | |
| Charitable donations and gifts from Schedule 2 | 112 | 6,900 | | | |
| Taxable capital gains from Schedule 6 | 113 | 26,660 | | | |
| Scientific research expenditures deducted per financial statements | 118 | 452,962 | | | |
| Non-deductible meals and entertainment expenses | 121 | 33,875 | | | |
| Other reserves on lines 270 and 275 from Schedule 13 | 125 | 1,038,077 | | | |
| Reserves from financial statements – balance at the end of the year | 126 | 64,247,387 | | | |
| Subtotal of additions | | 82,678,538 | ▶ | 82,678,538 | |
| **Other additions:** | | | | | |
| Financing fees deducted in books | 216 | 133,719 | | | |
| Non-deductible legal and accounting fees | 228 | 23,323 | | | |
| Taxable/non-deductible other comprehensive income items | 239 | 1,929,942 | | | |

## Miscellaneous other additions:

| | 1 Description 605 | 2 Amount 295 |
|---|---|---|
| 1 | Inducement under 12(1)(x) ITA | 148,828 |
| 2 | Overhead Adjustment for burdens and pole replacements | 150,688 |
| 3 | Foreign taxes on investment income | 88 |
| 4 | IFRS regulatory asset/liability adjustment | 4,436,424 |
| | **Total** of column 2 | 4,736,028 |

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| Total of column 2 ▶ | 296 | 4,736,028 | | | |
| Subtotal of other additions | 199 | 6,823,012 | ▶ | 6,823,012 | |
| **Total additions** | 500 | 89,501,550 | ▶ | 89,501,550 | B |
| Amount A **plus** amount B | | | | 103,010,032 | C |
| **Deduct:** | | | | | |
| Capital cost allowance from Schedule 8 | 403 | 14,489,063 | | | |
| SR&ED expenditures claimed in the year on line 460 from Form T661 | 411 | 362,631 | | | |
| Other reserves on line 280 from Schedule 13 | 413 | 985,066 | | | |
| Reserves from financial statements – balance at the beginning of the year | 414 | 67,749,576 | | | |
| Subtotal of deductions | | 83,586,336 | ▶ | 83,586,336 | |

## Other deductions:

## Miscellaneous other deductions:

| | 1 Description 705 | 2 Amount 395 |
|---|---|---|
| 1 | Financing fees | 128,321 |
| 2 | ATTC and CETC tax credits recorded in book income | 104,826 |

| | 1<br>Description<br>705 | 2<br>Amount<br>395 | | | |
|---|---|---|---|---|---|
| 3 | Capital gains allocated per T slips | 7,384 | | | |
| 4 | SR&ED income for accounting | 84,821 | | | |
| 5 | SR&ED expenditures capitalized for accounting | 309,886 | | | |
| 6 | Capitalized burdens and overheads | 1,832,553 | | | |
| 7 | Capitalized pole replacements | 1,580,503 | | | |
| | **Total** of column 2 | 4,048,294 ▶ | 396 | 4,048,294 | |
| | | Subtotal of other deductions | 499 | 4,048,294 ▶ | 4,048,294 |
| | | **Total deductions** | 510 | 87,634,630 ▶ | 87,634,630 D |

**Net income (loss) for income tax purposes** (amount C **minus** amount D) . . . . . . . . . . 15,375,402 E

Enter amount E on line 300 of the T2 return.

# Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

## Tax credits whose amount should be added to income

### Federal

| A | | |
|---|---|---|
| X | Investment tax credit from apprenticeship job creation expenditures | 12,000 |
| | Investment tax credit from child care spaces expenditures | |
| | Canadian film or video production tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Film or video production services tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| X | Investment tax credit claimed on contributions made to SR&ED farming organizations | |
| | Labour tax credit for qualifying journalism organizations | |

### Ontario

| A | | |
|---|---|---|
| X | Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations | 3,876 |
| X | Ontario co-operative education tax credit | 49,061 |
| X | Ontario apprenticeship training tax credit | 83,891 |
| | Ontario computer animation and special effects tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Ontario film and television tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Ontario production services tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Ontario interactive digital media tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Ontario sound recording tax credit*<br>* Please verify if the credit amount relates to depreciable property.<br>For more information, consult the Help (F1). | |
| | Ontario book publishing tax credit | |
| X | Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations | |
| | Ontario business-research institute tax credit | |
| | Ontario community food program donation tax credit for farmers | |

## Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 2**

# Charitable Donations and Gifts

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years. Provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File one completed copy of this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

## Part 1 – Charitable donations

| Charity/Recipient | Amount ($100 or more only) |
|---|---|
| HABITAT FOR HUMANITY | 1,400 |
| ST. CLAIR COLLEGE FOUNDATION | 2,000 |
| STREET HELP HOMELESS CENTRE OF WINDSOR | 2,000 |
| WINDSOR HOMES COALITION | 1,500 |
| CANADIAN CANCER SOCIETY | |
| MARYVALE | |
| UNITED WAY | |
| Subtotal | 6,900 |
| **Add:** Total donations of less than $100 each | |
| Total donations in current tax year | 6,900 |

## Part 1 – Charitable donations

| | Line | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Charitable donations at the end of the previous tax year | | | A | | |
| Charitable donations expired after 5 tax years* | 239 | | | | |
| Charitable donations at the beginning of the current tax year (amount A **minus** line 239) | 240 | | | | |
| Charitable donations transferred on an amalgamation or the wind-up of a subsidiary | 250 | | | | |
| Total charitable donations made in the current year (include this amount on line 112 of Schedule 1 Net Income (Loss) for Income Tax Purposes) | 210 | 6,900 | | 6,900 | 6,900 |
| Subtotal (line 250 **plus** line 210) | | 6,900 | B | 6,900 | 6,900 |
| Subtotal (line 240 **plus** amount B) | | 6,900 | C | 6,900 | 6,900 |
| Adjustment for an acquisition of control | 255 | | | | |
| Total charitable donations available (amount C **minus** line 255) | | 6,900 | D | 6,900 | 6,900 |
| Amount applied in the current year against taxable income (cannot be more than amount L in Part 2) (enter this amount on line 311 of the T2 return) | 260 | 6,900 | | 6,900 | 6,900 |
| Charitable donations closing balance (amount D **minus** line 260) | 280 | | | | |

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . . . . . . . . . . . . **262** ______

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . . . . . . . . . . . . . . ______ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **263** ______

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . . . . . . . . . . . . . . ______ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016 and before January 1, 2020) . . . . . . . . **265** ______

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . . . . . . . . . . . . . . . ______ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

## Amounts carried forward – Charitable donations

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2017-12-31 | | | |
| 2nd prior year | 2016-12-31 | | | |
| 3rd prior year | 2015-12-31 | | | |
| 4th prior year | 2014-12-31 | | | |
| 5th prior year | 2013-12-31 | | | |
| 6th prior year* | 2012-12-31 | | | |
| 7th prior year | 2011-12-31 | | | |
| 8th prior year | 2010-12-31 | | | |
| 9th prior year | 2009-12-31 | | | |
| 10th prior year | 2008-12-31 | | | |
| 11th prior year | 2007-12-31 | | | |
| 12th prior year | 2006-12-31 | | | |
| 13th prior year | 2005-12-31 | | | |
| 14th prior year | 2004-12-31 | | | |
| 15th prior year | 2003-12-31 | | | |
| 16th prior year | 2002-12-31 | | | |
| 17th prior year | 2001-12-31 | | | |
| 18th prior year | 2001-09-30 | | | |
| 19th prior year | 2000-12-31 | | | |
| 20th prior year | 1999-12-31 | | | |
| 21st prior year* | 1999-12-12 | | | |
| **Total** (to line A) | | | | |

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

## Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % . . . . . 11,531,552 E

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** . . . . . 225

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) . . . . . 227

The amount of the recapture of capital cost allowance in respect of charitable donations . . . . . 230

Proceeds of disposition, **less** outlays and expenses** . . . . . F

Capital cost** . . . . . G

Amount F or G, whichever is less . . . . . 235

Amount on line 230 or 235, whichever is less . . . . . H

Subtotal (**add** line 225, 227, and amount H) I

Amount I **multiplied** by 25 % J

Subtotal (amount E **plus** amount J) 11,531,552 K

**Maximum allowable deduction for charitable donations** (enter amount D from Part 1, amount K, or net income for tax purposes, whichever is less) . . . . . 6,900 L

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

## Part 3 – Gifts of certified cultural property

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Gifts of certified cultural property at the end of the previous tax year | | | M | | |
| Gifts of certified cultural property expired after 5 tax years* | 439 | | | | |
| Gifts of certified cultural property at the beginning of the current tax year (amount M **minus** line 439) | 440 | | | | |
| Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary | 450 | | | | |
| Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1) | 410 | | | | |
| Subtotal (line 450 **plus** line 410) | | | N | | |
| Subtotal (line 440 **plus** amount N) | | | O | | |
| Adjustment for an acquisition of control | 455 | | | | |
| Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return) | 460 | | | | |
| Subtotal (line 455 **plus** line 460) | | | P | | |
| Gifts of certified cultural property closing balance (amount O **minus** amount P) | 480 | | | | |

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

## Amount carried forward – Gifts of certified cultural property

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2017-12-31 | | | |
| 2nd prior year | 2016-12-31 | | | |
| 3rd prior year | 2015-12-31 | | | |
| 4th prior year | 2014-12-31 | | | |
| 5th prior year | 2013-12-31 | | | |
| 6th prior year* | 2012-12-31 | | | |
| 7th prior year | 2011-12-31 | | | |
| 8th prior year | 2010-12-31 | | | |
| 9th prior year | 2009-12-31 | | | |
| 10th prior year | 2008-12-31 | | | |
| 11th prior year | 2007-12-31 | | | |
| 12th prior year | 2006-12-31 | | | |
| 13th prior year | 2005-12-31 | | | |
| 14th prior year | 2004-12-31 | | | |
| 15th prior year | 2003-12-31 | | | |
| 16th prior year | 2002-12-31 | | | |
| 17th prior year | 2001-12-31 | | | |
| 18th prior year | 2001-09-30 | | | |
| 19th prior year | 2000-12-31 | | | |
| 20th prior year | 1999-12-31 | | | |
| 21st prior year* | 1999-12-12 | | | |
| **Total** | | | | |

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

## Part 4 – Gifts of certified ecologically sensitive land

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Gifts of certified ecologically sensitive land at the end of the previous tax year | | | Q | | |
| Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014* | 539 | | | | |
| Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount Q **minus** line 539) | 540 | | | | |
| Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary | 550 | | | | |
| Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1) | 520 | | | | |
| Subtotal (line 550 **plus** line 520) | | | R | | |
| Subtotal (line 540 **plus** amount R) | | | S | | |
| Adjustment for an acquisition of control | 555 | | | | |
| Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return) | 560 | | | | |
| Subtotal (line 555 **plus** line 560) | | | T | | |
| Gifts of certified ecologically sensitive land closing balance (amount S **minus** amount T) | 580 | | | | |

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

## Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . . . . . . . . . . . . . . .

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2017-12-31 | | | |
| 2nd prior year | 2016-12-31 | | | |
| 3rd prior year | 2015-12-31 | | | |
| 4th prior year | 2014-12-31 | | | |
| 5th prior year | 2013-12-31 | | | |
| 6th prior year* | 2012-12-31 | | | |
| 7th prior year | 2011-12-31 | | | |
| 8th prior year | 2010-12-31 | | | |
| 9th prior year | 2009-12-31 | | | |
| 10th prior year | 2008-12-31 | | | |
| 11th prior year* | 2007-12-31 | | | |
| 12th prior year | 2006-12-31 | | | |
| 13th prior year | 2005-12-31 | | | |
| 14th prior year | 2004-12-31 | | | |
| 15th prior year | 2003-12-31 | | | |
| 16th prior year | 2002-12-31 | | | |
| 17th prior year | 2001-12-31 | | | |
| 18th prior year | 2001-09-30 | | | |
| 19th prior year | 2000-12-31 | | | |
| 20th prior year | 1999-12-31 | | | |
| 21st prior year* | 1999-12-12 | | | |
| **Total** | | | | |

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

## Part 5 – Additional deduction for gifts of medicine

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Additional deduction for gifts of medicine at the end of the previous tax year | | | U | | |
| Additional deduction for gifts of medicine expired after 5 tax years* | 639 | | | | |
| Additional deduction for gifts of medicine at the beginning of the current tax year (amount U **minus** line 639) | 640 | | | | |
| Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary | 650 | | | | |
| Additional deduction for gifts of medicine made before March 22, 2017: | | | | | |
| Proceeds of disposition | 602 | | | | |
| Cost of gifts of medicine made before March 22, 2017 | 601 | | | | |
| Subtotal (line 602 **minus** line 601) | | | V | | |
| Amount V **multiplied** by 50 % | | | W | | |
| Eligible amount of gifts | 600 | | | | |

**Federal**

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 **610** ______

**Québec**

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

**Alberta**

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

where:

**a** is the **lesser** of line 601 and amount W

**b** is the eligible amount of gifts (line 600)

**c** is the proceeds of disposition (line 602)

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Subtotal (line 650 **plus** line 610) | | | X | | |
| Subtotal (line 640 **plus** amount X) | | | Y | | |
| Adjustment for an acquisition of control | 655 | | | | |
| Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return) | 660 | | | | |
| Subtotal (line 655 **plus** line 660) | | | Z | | |
| Additional deduction for gifts of medicine closing balance (amount Y **minus** amount Z) | 680 | | | | |

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

## Amounts carried forward – Additional deduction for gifts of medicine

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2017-12-31 | | | |
| 2nd prior year | 2016-12-31 | | | |
| 3rd prior year | 2015-12-31 | | | |
| 4th prior year | 2014-12-31 | | | |
| 5th prior year | 2013-12-31 | | | |
| 6th prior year* | 2012-12-31 | | | |
| 7th prior year | 2011-12-31 | | | |
| 8th prior year | 2010-12-31 | | | |
| 9th prior year | 2009-12-31 | | | |
| 10th prior year | 2008-12-31 | | | |
| 11th prior year | 2007-12-31 | | | |
| 12th prior year | 2006-12-31 | | | |
| 13th prior year | 2005-12-31 | | | |
| 14th prior year | 2004-12-31 | | | |
| 15th prior year | 2003-12-31 | | | |
| 16th prior year | 2002-12-31 | | | |
| 17th prior year | 2001-12-31 | | | |
| 18th prior year | 2001-09-30 | | | |
| 19th prior year | 2000-12-31 | | | |
| 20th prior year | 1999-12-31 | | | |
| 21st prior year* | 1999-12-12 | | | |
| **Total** | | | | |

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

## Québec – Gifts of musical instruments

| | | |
|---|---|---|
| Gifts of musical instruments at the end of the previous tax year | | A |
| **Deduct:** Gifts of musical instruments expired after twenty tax years | | B |
| Gifts of musical instruments at the beginning of the tax year | | C |
| **Add:** | | |
| Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary | | D |
| Total current-year gifts of musical instruments | | E |
| Subtotal (line D **plus** line E) | | F |
| **Deduct:** Adjustment for an acquisition of control | | G |
| Total gifts of musical instruments available | | H |
| **Deduct:** Amount applied against taxable income (enter this amount on line 255 of form CO-17) | | I |
| Gifts of musical instruments closing balance | | J |

## Amounts carried forward – Gifts of musical instruments

| Year of origin: | | Québec |
|---|---|---|
| 1st prior year | 2017-12-31 | |
| 2nd prior year | 2016-12-31 | |
| 3rd prior year | 2015-12-31 | |
| 4th prior year | 2014-12-31 | |
| 5th prior year | 2013-12-31 | |
| 6th prior year* | 2012-12-31 | |
| 7th prior year | 2011-12-31 | |
| 8th prior year | 2010-12-31 | |
| 9th prior year | 2009-12-31 | |
| 10th prior year | 2008-12-31 | |
| 11th prior year | 2007-12-31 | |
| 12th prior year | 2006-12-31 | |
| 13th prior year | 2005-12-31 | |
| 14th prior year | 2004-12-31 | |
| 15th prior year | 2003-12-31 | |
| 16th prior year | 2002-12-31 | |
| 17th prior year | 2001-12-31 | |
| 18th prior year | 2001-09-30 | |
| 19th prior year | 2000-12-31 | |
| 20th prior year | 1999-12-31 | |
| 21st prior year* | 1999-12-12 | |
| **Total** | | |

* These gifts expired in the current year.

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**Schedule 3**

# Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3).
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the code that applies to the deductible taxable dividend.

## Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

**Important instructions to follow if the payer corporation is connected**

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes**.

| | A<br>Name of payer corporation<br>(from which the corporation received the dividend)<br>200 | A1 | B<br>Enter 1 if payer corporation is **connected**<br>205 | C<br>Business Number of **connected** corporation<br>210 | D<br>Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD<br>220 | E<br>Non-taxable dividends under section 83<br>230 |
|---|---|---|---|---|---|---|
| 1 | RBC Summary | | 2 | | | |
| | | | | | **Total of column E** (enter amount on line 402 of Schedule 1) | |

## Part 1 – Dividends received in the tax year (continued)

| | F<br>Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1]<br>240 | F1 | G<br>Eligible dividends included in column F<br>242 | H<br>Total taxable dividends paid by **connected** payer corporation (for tax year in column D)<br>250 | I<br>Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2]<br>260 | J<br>Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3%[note 3]<br>265 | K<br>Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3%[note 4]<br>275 |
|---|---|---|---|---|---|---|---|
| 1 | 5,257 | 1 | 5,248 | | | 2,012 | 2,015 |

| | | | |
|---|---|---|---|
| Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) | | | 1A |
| Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) | | 5,257 | 1B |
| Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 Return) | | 5,257 | 1C |
| Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) | | | 1D |
| Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) | | 5,248 | 1E |
| Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) | 1F | | |
| Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) | 2,015 1G | | |
| Subtotal (amount 1F **plus** amount 1G) | 2,015 ▶ | 2,015 | 1H |
| Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) | 1I | | |
| Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) | 2,012 1J | | |
| Subtotal (amount 1I **plus** amount 1J) | 2,012 ▶ | 2,012 | 1K |
| Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) | | 3 | 1L |

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column J or column K whichever one applies. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column F.

## Part 2 – Calculation of Part IV tax payable

| | | | | |
|---|---|---|---|---|
| Part IV tax on dividends received before deductions (amount 1H in part 1) | | 2,015 | 2A | |
| Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) | 320 | | | |
| Subtotal (amount 2A **minus** line 320) | | 2,015 | ▶ | 2,015 2B |
| Current-year non-capital loss claimed to reduce Part IV tax | 330 | | | |
| Non-capital losses from previous years claimed to reduce Part IV tax | 335 | | | |
| Current-year farm loss claimed to reduce Part IV tax | 340 | | | |
| Farm losses from previous years claimed to reduce Part IV tax | 345 | | | |
| Total losses applied against Part IV tax (total of lines 330 to 345) | | | 2C | |
| Amount 2C **multiplied** by 38 1/3 % | | | | 2D |
| **Part IV tax payable** (amount 2B **minus** amount 2D, if negative enter "0") (enter amount on line 712 of the T2 return) | | | 360 | 2,015 |

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

| | | |
|---|---|---|
| Part IV tax before deductions on taxable dividends received from connected corporations note 5 (amount 1F in part 1) | | 2E |
| Amount 4A from Schedule 43 | | 2F |
| **Part IV tax payable on taxable dividends received from connected corporations** (amount 2E minus amount 2F, if negative enter "0") (enter at amount L on page 7 of the T2 return) | | 2G |

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

| | | |
|---|---|---|
| Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) | | 2H |
| Amount 4C from Schedule 43 | | 2I |
| **Part IV tax payable on eligible dividends received from non-connected corporations** (amount 2H minus amount 2I, if negative enter "0") (enter at amount M on page 7 of the T2 return) | | 2J |

5 To the extent of a dividend refund to the connected payer corporation from its eligible refundable dividend tax on hand (ERDTOH). Otherwise, the amount 2E is nil.

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

| | L<br>Name of connected recipient corporation<br>400 | M<br>Business Number<br>410 | N<br>Tax year-end of connected recipient corporation in which the dividends in column O were received YYYYMMDD<br>420 | O<br>Taxable dividends paid to connected corporations<br>430 | P<br>Eligible dividends included in column O<br>440 |
|---|---|---|---|---|---|
| 1 | Windsor Canada Utilities | 86712 9181 RC0001 | 2018-12-31 | 3,000,000 | |
| 2 | | | | | |
| | | | | 3,000,000<br>(Total of column O) | (Total of column P) |

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

| | | | |
|---|---|---|---|
| Total taxable dividends paid in the tax year to other than connected corporations | | 450 | |
| Eligible dividends included in line 450 | 455 | | |
| Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column O **plus** line 450) | | 460 | 3,000,000 |
| Total eligible dividends paid in the tax year (total of column P **plus** line 455) | | 465 | |
| Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465) | | 470 | 3,000,000 |

Complete this part to determine the following amounts in order to calculate the dividend refund.

| | | |
|---|---|---|
| Line 465 **multiplied** by 38 1/3 % (enter at amount AA on page 7 of the T2 return) | | 3A |
| Line 470 **multiplied** by 38 1/3 % (enter at amount DD on page 7 of the T2 return) | 1,150,000 | 3B |

## Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

| | | | | |
|---|---|---|---|---|
| Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) | | | 3,000,000 | |
| Other dividends paid in the tax year (total of 510 to 540) | | | | |
| Total dividends paid in the tax year | | 500 | 3,000,000 | |
| Dividends paid out of capital dividend account | 510 | | | |
| Capital gains dividends | 520 | | | |
| Dividends paid on shares described in subsection 129(1.2) | 530 | | | |
| Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year | 540 | | | |
| Subtotal (total of lines 510 to 540) | | ► | | 4A |
| **Total taxable dividends paid in the tax year that qualify for a dividend refund** (Line 500 **minus** amount 4A) | | | 3,000,000 | 4B |

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**Schedule 5**

# Tax Calculation Supplementary – Corporations

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

## Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413)

| A Jurisdiction. Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year * | | B Total salaries and wages paid in jurisdiction | C (B x taxable income) / G | D Gross revenue | E (D x taxable income) / H | F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 Yes | 103 | | 143 | | |
| Newfoundland and Labrador Offshore | 004 Yes | 104 | | 144 | | |
| Prince Edward Island | 005 Yes | 105 | | 145 | | |
| Nova Scotia | 007 Yes | 107 | | 147 | | |
| Nova Scotia Offshore | 008 Yes | 108 | | 148 | | |
| New Brunswick | 009 Yes | 109 | | 149 | | |
| Quebec | 011 Yes | 111 | | 151 | | |
| Ontario | 013 Yes | 113 | | 153 | | |
| Manitoba | 015 Yes | 115 | | 155 | | |
| Saskatchewan | 017 Yes | 117 | | 157 | | |
| Alberta | 019 Yes | 119 | | 159 | | |
| British Columbia | 021 Yes | 121 | | 161 | | |
| Yukon | 023 Yes | 123 | | 163 | | |
| Northwest Territories | 025 Yes | 125 | | 165 | | |
| Nunavut | 026 Yes | 126 | | 166 | | |
| Outside Canada | 027 Yes | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in subsection 400(2)

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| 15,363,245 | | 15,363,245 | 1,766,773 |

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | 1,766,773 | | | |
| Ontario small business deduction (from Schedule 500) | 402 | | | | |
| Subtotal (line 270 **minus** line 402) | | 1,766,773 | ▶ | 1,766,773 | 5A |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | | |
| Subtotal (line 276 **plus** line 277) | | | ▶ | | 5B |
| Gross Ontario tax (amount 5A **plus** amount 5B) | | | | 1,766,773 | 5C |
| Ontario resource tax credit (from Schedule 504) | 404 | | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | | |
| Ontario non-refundable tax credits (total of lines 404 to 415) | | | ▶ | | 5D |
| Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0") | | | | 1,766,773 | 5E |
| Ontario research and development tax credit (from Schedule 508) | | | 416 | 18,373 | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0") | | | | 1,748,400 | 5F |
| Ontario corporate minimum tax credit (from Schedule 510) | | | 418 | | |
| Ontario community food program donation tax credit for farmers (from Schedule 2) | | | 420 | | |
| Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative enter "0") | | | | 1,748,400 | 5G |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | | |
| Subtotal (line 278 **plus** line 280) | | | ▶ | | 5H |
| Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H) | | | | 1,748,400 | 5I |
| Ontario qualifying environmental trust tax credit | 450 | | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 38,661 | | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 50,165 | | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | 8,000 | | | |
| Ontario refundable tax credits (total of lines 450 to 470) | | 96,826 | ▶ | 96,826 | 5J |
| **Net Ontario tax payable or refundable tax credit** (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255. | | | 290 | 1,651,574 | |

## Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

| | | |
|---|---|---|
| **Net provincial and territorial tax payable or refundable tax credits** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | **255** | 1,651,574 |

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**Schedule 6**

# Summary of Dispositions of Capital Property

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

## Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . **050** 1 Yes [ ] 2 No [X]

If **yes**, attach a statement specifying which properties such a designation applies to.

In the various sections of this form:

- The abbreviation **FS** (for foreign source) is used to indicate the capital gain or loss arising from foreign property;
- The abbreviation **PA** (for passive asset) is used to indicate the capital gain or loss arising from the disposition of an asset other than an active asset of the corporation.

## Part 1 – Shares

| 1 Number of shares 100 | 2 Name of corporation in which the shares are held 105 | 3 Class of shares 106 | 4 Date of Acquisition YYYY/MM/DD 110 | 5 Proceeds of disposition 120 | 6 Adjusted cost base 130 | 7 Outlays and expenses from disposition 140 | 8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150 | A FS | A PA |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | **Totals** | | | | | | |

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . . . . . . . . . . . . . . . . . **160** ______

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . . . . . . . . . . . . . . . . . . . . . . ______ A

## Part 2 – Real estate (Do not include losses on depreciable property)

| | 1 Municipal address of real estate<br>1 = Address 1<br>2 = Address 2<br>3 = City<br>4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code<br>200 | 2 Date of Acquisition YYYY/MM/DD 210 | 3 Proceeds of disposition 220 | 4 Adjusted cost base 230 | 5 Outlays and expenses from disposition 240 | 6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250 | A FS | A PA |
|---|---|---|---|---|---|---|---|---|
| 1 | 3495 Bloomfield | | 36,989 | 6,737 | | 30,252 | | |
| | | | | | | | | |
| | Windsor | | | | | | | |
| | ON CA N9C 1R6 | | | | | | | |
| | | **Totals** | 36,989 | 6,737 | | 30,252 | B | |

## Part 3 – Bonds

| 1 Face value of bonds 300 | 2 Maturity date YYYY/MM/DD 305 | 3 Name of bond issuer 307 | 4 Date of Acquisition YYYY/MM/DD 310 | 5 Proceeds of disposition 320 | 6 Adjusted cost base 330 | 7 Outlays and expenses from disposition 340 | 8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350 | A FS | A PA |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | **Totals** | | | | | C | |

## Part 4 – Other properties (Do not include losses on depreciable property)

| | 1 Description of other property 400 | 2 Date of Acquisition YYYY/MM/DD 410 | 3 Proceeds of disposition 420 | 4 Adjusted cost base 430 | 5 Outlays and expenses from disposition 440 | 6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450 | A FS | PA |
|---|---|---|---|---|---|---|---|---|
| 1 | 3495 Bloomfield | | 19,177 | 3,493 | | 15,684 | | |
| | | **Totals** | 19,177 | 3,493 | | 15,684 | D | |

**Note**
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

## Part 5 – Personal-use property (Do not include listed personal property)

| 1 Description of personal-use property 500 | 2 Date of Acquisition YYYY/MM/DD 510 | 3 Proceeds of disposition 520 | 4 Adjusted cost base 530 | 5 Outlays and expenses from disposition 540 | 6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550 | A FS | PA |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | **Totals** | | | | | E | |

**Note**
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

## Part 6 – Listed personal property

| 1 Description of listed personal property 600 | 2 Date of Acquisition YYYY/MM/DD 610 | 3 Proceeds of disposition 620 | 4 Adjusted cost base 630 | 5 Outlays and expenses from disposition 640 | 6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650 | A FS | PA |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | **Totals** | | | | | | |

**Deduct**: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **655** ____________

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . . . . . . . . . . . . ____________ **F**

**Note**
Net listed personal property losses can only be applied against listed personal property gains.

## Part 7 – Property qualifying for and resulting in an allowable business investment loss

| 1 Name of small business corporation 900 | 2 Shares, enter 1; debt, enter 2 905 | 3 Date of Acquisition YYYY/MM/DD 910 | 4 Proceeds of disposition 920 | 5 Adjusted cost base 930 | 6 Outlays and expenses from disposition 940 | 7 Loss only (column 4 **minus** columns 5 and 6) 950 | A FS | PA |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| | | **Totals** | | | | | | |

Allowable business investment losses (ABILs) . . . . . . . . . . . Total of Column 7 ____________ x 50.0000 % = ____________ **G**

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

**Note**
Properties listed in Part 7 should not be included in any other parts of this schedule.

## Part 8 – Capital gains or losses

| | | | | FS | PA |
|---|---|---|---|---|---|
| Total of amounts A to F (do not include amount F if it is a loss) | | 45,936 | H | | |
| **Add:** | | | | | |
| Capital gains dividend received in the year | 875 | 7,384 | I | | |
| Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves,* enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*) | 880 | | J | | |
| Subtotal (total of amounts H to J) | | 53,320 | K | | |
| **Deduct**: Capital gains reserve closing balance (from Schedule 13) | 885 | | L | | |
| Capital gains or losses, excluding ABILs (amount K **minus** amount L) | 890 | 53,320 | M | | |

## Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . 53,320 N

**Deduct** the following amounts included in amount N, that are subject to the zero inclusion rate:

**Note**
When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

| | | | | | | FS | PA |
|---|---|---|---|---|---|---|---|
| Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act | 895 | | a | | | | |
| Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act* | 896 | | b | | | | |
| **Exempt** portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) | | | b-2 | | | | |
| Subtotal (amount a **plus** amount b **plus** b-2) | | | ▶ | | O | | |
| Subtotal (amount N **minus** amount O) | | | | 53,320 | P | | |

**Add:**

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

| | | | | | | FS | PA |
|---|---|---|---|---|---|---|---|
| Exemption threshold at time of disposition | 897 | | c | | | | |
| The total of all capital gains from the disposition of the actual property | 898 | | d | | | | |
| Amount c or amount d, whichever is less | | | | | Q | | |

| | | | | | |
|---|---|---|---|---|---|
| Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) | | x 2 = | 899 | | R |
| Subtotal (total of amounts P to R) | | | | 53,320 | S |
| **Deduct:** | | | | | |
| Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) | | x 2 = | 901 | | T |
| Total capital gains or losses (amount S **minus** amount T) | | | | 53,320 | U |

**Taxable capital gains or total capital losses**

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") . . . V
Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U 53,320 multiplied by 50.0000 %;
if amount U is negative, enter "0") . . . 26,660 W
Enter amount W on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

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**Schedule 7**

# Aggregate Investment Income and Income Eligible for the Small Business Deduction

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule if you are a Canadian-controlled private corporation (CCPC) to calculate:
  - your aggregate investment income and foreign investment income, as defined in subsection 129(4), to determine the refundable portion of Part I tax, and your adjusted aggregate investment income, as defined in subsection 125(7), for the purpose of the business limit reduction
  - your **specified partnership income**, as defined in subsection 125(7), if you are a member (or **designated member**) of one or more partnerships, and
  - your income from an active business carried on in Canada eligible for the small business deduction including any **specified corporate income** as defined in subsection 125(7)
- Use this schedule if another CCPC is making an assignment of **business limit** under subsection 125(3.2) to you.
- Use this schedule if you are a corporation that is a member of a partnership to assign **specified partnership business limit** to a **designated member** under subsection 125(8).
  **Note**: If you are a corporation that is not a CCPC, **only** complete Table 1 (columns A1, B1, C1, G1, H1 and J1) and Table 3 to make this assignment.
- The adjusted aggregate investment income, for the purpose of the business limit reduction, also applies to a tax year of a corporation that begins before 2019 and ends after 2018 under the following circumstances:
  - the corporation's preceding tax year was, because of a transaction or event or a series of transactions or events, shorter than it would have been in the absence of that transaction, event or series, and
  - one of the reasons for the transaction, event or series was to defer the application of subsections 125(5.1), (5.2) and (7) to the corporation
- All legislative references are to the Income Tax Act.
- For more information, see **Small Business Deduction** and **Refundable Portion of Part I Tax** in Guide T4012, T2 Corporation – Income Tax Guide.
- See the notes at the end of the form.

## Part 1 – Aggregate investment income

Aggregate investment income is all **world** source income.

| | | | | | |
|---|---|---|---|---|---|
| Eligible portion of taxable capital gains for the year | | | 002 | 26,660 | |
| Eligible portion of allowable capital losses for the year (including allowable business investment losses) | | | 012 | | |
| Net capital losses of previous years claimed on line 332 on the T2 return | | | 022 | | |
| Subtotal (line 012 **plus** line 022) | | | | | A |
| Line 002 **minus** amount A (if negative, enter "0") | | | | 26,660 | B |
| Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada) | | | 032 615,269 | | |
| Exempt income | 042 | | | | |
| Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year | 052 | | | | |
| Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses) | 062 | 5,257 | | | |
| Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) | 072 | | | | |
| Subtotal (**add** lines 042, 052, 062 and 072) | | 5,257 | 5,257 | | C |
| Subtotal (line 032 **minus** amount C) | | | 610,012 | 610,012 | D |
| Amount B **plus** amount D | | | | 636,672 | E |
| Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada) | 082 | | | | |
| Amount E **minus** line 082 (if negative, enter "0") (enter on line 440 of the T2 return) | 092 | | | 636,672 | |

## Part 2 – Adjusted aggregate investment income

| | | | |
|---|---|---|---|
| Eligible portion of taxable capital gains for the year (other than taxable capital gains from the disposition of an active asset note 13) | 705 | | |
| Eligible portion of allowable capital losses for the year (including allowable business investment losses) (other than allowable capital losses from the disposition of an active asset note 13) | 710 | | |
| Subtotal (line 705 **minus** line 710) (if negative, enter "0") | | | F |
| Total income from property note 14 | 715 | 615,269 | |
| Exempt income | 720 | | |
| Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year | 725 | | |
| Dividends from connected corporations | 730 | | |
| Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) | 735 | | |
| Subtotal (**add** lines 720, 725, 730 and 735) | | | G |
| Subtotal (line 715 **minus** amount G) | | 615,269 | 615,269 H |
| Amount F **plus** amount H | | | 615,269 I |
| Total losses from property note 14 | 740 | | |
| Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year | 741 | | |
| **Adjusted aggregate investment income** (amount I **minus** line 740, **plus** line 741) (if negative, enter "0") | 745 | | 615,269 |

**If this is your first tax year starting after 2018, complete the following portion.**

| | | | |
|---|---|---|---|
| Eligible portion of taxable capital gains for each tax year that ended in the preceding calendar year (other than taxable capital gains from the disposition of an active asset note 13) | | | 2A |
| Eligible portion of allowable capital losses for each tax year that ended in the preceding calendar year (including allowable business investment losses)(other than allowable capital losses from the disposition of an active asset note 13) | | | 2B |
| Subtotal (amount 2A **minus** amount 2B) (if negative, enter "0") | | | 2C |
| Total income from property for each tax year that ended in the preceding calendar year note 14 | | 2D | |
| Exempt income for each tax year that ended in the preceding calendar year | 2E | | |
| Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for each tax year that ended in the preceding calendar year | 2F | | |
| Dividends from connected corporations for each tax year that ended in the preceding calendar year | 2G | | |
| Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) for each tax year that ended in the preceding calendar year | 2H | | |
| Subtotal (**add** amounts 2E, 2F, 2G and 2H) | | 2I | |
| Subtotal (amount 2D **minus** amount 2I) | | | 2J |
| Amount 2C **plus** amount 2J | | | 2K |
| Total losses from property for each tax year that ended in the preceding calendar year note 14 | | | 2L |
| Amount, if any, deducted under subsection 91(4) in computing the corporation's income for each tax year that ended in the preceding calendar year | 742 | | |
| **Adjusted aggregate investment income** (amount 2K **minus** amount 2L, **plus** line 742) (if negative, enter "0") | 744 | | |

(enter the total of line 744 and the adjusted aggregate investment income of all associated corporations on line 417 of the T2 return)

## Part 3 – Foreign investment income

Foreign investment income is all income from sources **outside Canada**.

| | | | | |
|---|---|---|---|---|
| Eligible portion of taxable capital gains for the year | | 001 | | |
| Eligible portion of allowable capital losses for the year (including allowable business investment losses) | | 009 | | |
| Subtotal (line 001 **minus** line 009) (if negative, enter "0") | | | | J |
| Total income from property from a source **outside Canada** (net of related expenses) | 019 | 849 | | |
| Exempt income | 029 | | | |
| Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses) | 049 | | | |
| Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) | 059 | | | |
| Subtotal (**add** lines 029, 049, and 059) | | | | K |
| Subtotal (line 019 **minus** amount K) | | 849 | 849 | L |
| Amount J **plus** amount L | | | 849 | M |
| Total losses from property from a source **outside Canada** | | 069 | | |
| Amount M **minus** line 069 (if negative, enter "0") (enter on line 445 of the T2 return) | | 079 | 849 | |

## Part 3A – Canadian and foreign investment income and adjusted aggregate investment income calculation

| | A Canadian investment income | B Foreign investment income | C Adjusted aggregate investment income* | |
|---|---|---|---|---|
| Eligible portion of the taxable capital gains for the year before taking into account the capital gains reserves (federal) of Schedule 13* | 26,660 | | | 1.1 |
| Eligible portion of capital gains reserves (addition/deduction)*, ** | | | | 1.2 |
| Taxable capital gains under section 34.2 (line 275 on Schedule 73)** | | | | 1.3 |
| Eligible portion of the taxable capital gains for the year (**add** amounts 1.1, 1.2, and 1.3) | 26,660 | | | 1 |
| Eligible portion of allowable capital losses for the year (including allowable business investment losses)* | | | | 2.1 |
| Net capital losses of previous years (line 332 on the T2 return) | | | | 2.2 |
| Allowable capital losses under section 34.2 (line 285 of Schedule 73)** | | | | 2.3 |
| Allowable capital losses for the year (**add** amounts 2.1, 2.2 and 2.3) | | | | 2 |
| Amount 1 **minus** amount 2 (if negative, enter "0") | 26,660 | | | 3 |
| Taxable dividends | 5,257 | | 5,257 | 4.1 |
| Rental property income (under regulation 1100(11)) | | | | 4.2 |
| Other property income* | 609,163 | 849 | 610,012 | 4.3 |
| Property income under section 34.2 (line 280 of Schedule 73)** | | | | 4.4 |
| Total property income (**add** amounts 4.1, 4.2, 4.3 and 4.4) | 614,420 | 849 | 615,269 | 4 |
| Exempt income | | | | 5.1 |
| Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year | | | | 5.2 |
| Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)* | 5,257 | | | 5.3 |
| Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) | | | | 5.4 |
| **Add** amounts 5.1, 5.2, 5.3 and 5.4 | 5,257 | | | 5 |
| Amount 4 **minus** amount 5 | 609,163 | 849 | 615,269 | 6 |
| Amount 3 **plus** amount 6 | 635,823 | 849 | 615,269 | 7 |
| Rental property losses (under regulation 1100(11)) | | | | 8.1 |
| Dividend losses | | | | 8.2 |
| Other property losses* | | | | 8.3 |
| Property losses under section 34.2 (line 280 of Schedule 73)** | | | | 8.4 |
| Total property losses (**add** amounts 8.1, 8.2, 8.3 and 8.4) | | | | 8 |
| Amount 7 **minus** amount 8 (if negative, enter "0") | 635,823 | 849 | | 9 |
| Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year | | | | 10 |
| Amount 7 **minus** amount 8 **plus** amount 10 (if negative, enter "0") | | | 615,269 | 11 |

* To calculate the adjusted aggregate investment income under column C:

- On lines 1.1, 1.2 and 2.1, only capital gains and losses resulting from the disposition of property other than an active asset (as defined under subsection 125(7) ITA) are to be taken into account.
- On line 4.3, include amounts in respect of a life insurance policy that are included in computing the corporation's income for the year (even if those amounts are not included in the calculation of the corporation's investment income in column A and B) as well as the income from a specified foreign investment business.
- On line 5.3, only the dividends received from a connected corporation should be included.
- On line 8.3, include the loss from a specified foreign investment business.

For more information on the calculation of the adjusted aggregate investment income, consult notes 13 and 14 at the end of this form as well as the Help (F1).

** When an amount is entered on these lines in column B, it reduces the corresponding amount in column A. For more information, consult the Help (F1).

| Net taxable dividends | A* | Canadian | Foreign | Total |
|---|---|---|---|---|
| Taxable dividends deducted per Schedule 3 | | 5,257 | | 5,257 |
| **Less:** Expenses related to such dividends | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| Total expenses | | | | |
| Net taxable dividends | | 5,257 | | 5,257 |

* Column A – Enter an “X” if the expense is related to a dividend received from a connected corporation.

## Part 4 – Specified partnership income

### Table 1 – Specified partnership income

| A | A1 | 1A |
|---|---|---|
| Is the corporation a designated member of the partnership? | Partnership name 200 | Partnership's account number |
| Yes No | | |

| B1 | C1 | D1 | 1D | 2D | E1 | F1 |
|---|---|---|---|---|---|---|
| Total income (loss) of partnership from an active business 300 | Corporation's share of amount in column B1 310 | Income of the corporation from providing (directly or indirectly) services or property to the partnership 311 | Prorated amounts calculated under section 34.2 note 1 | Expenses the corporation incurred to earn partnership income | Adjustments (column 1D **minus** column 2D) 315 | Corporation's income (loss) in respect of the partnership note 2 (**add** columns C1, D1 and E1) 320 |
| | | | | | | |

Total 350

| G1 | H1 | I1 | J1 | K1 | L1 | M1 |
|---|---|---|---|---|---|---|
| Number of days in the partnership's fiscal period 325 | Prorated business limit notes 2 and 3 (column C1 ÷ column B1) × [$ 500 000 × (column G1 ÷ 365)] (if column C1 is negative, enter "0") 330 | Specified partnership business limit **assigned to you** (from H2 in Table 2) note 5 335 | Specified partnership business limit **assigned by you** from F3 in Table 3) note 6 336 | Specified partnership business limit amount (column H1 **plus** column I1 **minus** column J1) | Column F1 **minus** column K1 (if negative, enter "0") | Lesser of columns F1 and K1 (if column F1 is negative, enter "0") note 4 340 |
| | | | | | | |

Total 385 360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . . . . . . . . . 370

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column F1) . . . . . . . . . . . . . . . . . . . . . . . . . . . 380

Subtotal (line 370 **plus** line 380) N

Amount at line 385 or amount N, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 390

**Specified partnership income** (line 360 **plus** line 390) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 400
(enter at amount R in Part 5)

## Part 4 – Specified partnership income (continued)

Tables 2 and 3 are used to make an assignment of **specified partnership business limit** under subsection 125(8). A person that is a member of a partnership can make an assignment of **specified partnership business limit** under subsection 125(8) to a **designated member**.

If you are a CCPC that is a designated member and **receiving** specified partnership business limit from a person that is a member of the partnership, complete Table 2.

If you are a corporation that is a member of the partnership and **assigning** specified partnership business limit to a designated member, complete Table 3.

### Table 2 – A member is assigning to you specified partnership business limit under subsection 125(8)

| A2 | 2A | B2 |
|---|---|---|
| Partnership name 405 | Partnership's account number | Name of the member 406 |
| | | |

| C2 | D2 | E2 | F2 | G2 | H2 |
|---|---|---|---|---|---|
| Business number of the member (if applicable) 410 | Social insurance number of the member (if applicable) 411 | Trust account number of the member (if applicable) 412 | Tax year start of the member (yyyymmdd) 415 | Tax year-end of the member (yyyymmdd) 416 | Specified partnership business limit assigned to you by the member note 7 420 |
| | | | | | |

### Table 3 – You are assigning to a designated member (CCPC) specified partnership business limit under subsection 125(8)

| A3 | 3A | B3 |
|---|---|---|
| Partnership name 425 | Partnership's account number | Name of the designated member 426 |
| | | |

| C3 | D3 | E3 | F3 |
|---|---|---|---|
| Business number of the designated member 430 | Tax year start of the designated member (yyyymmdd) 435 | Tax year-end of the designated member (yyyymmdd) 436 | Specified partnership business limit assigned by you to the designated member note 8 440 |
| | | | |

## Part 5 – Partnership income not eligible for the small business deduction

Corporation's income from active businesses carried on in Canada as a member or designated member of a partnership (after deducting related expenses) – from line 350 in Part 4 (if the net amount is negative, enter "0" on line 450) . . . . . . . . . . . . . . . ______ O

Specified partnership loss (from line 380 in Part 4) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ P

Subtotal (amount O **plus** amount P) ______ Q

Specified partnership income (from line 400 in Part 4) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ R

**Partnership income not eligible for the small business deduction** (amount Q **minus** amount R) . . . . . . . . . . . . . . . . 450 ______
(enter at amount Z in Part 6)

## Part 6 – Income eligible for the small business deduction

| | | | | |
|---|---|---|---|---|
| Net income for income tax purposes from line 300 of the T2 return | | 15,375,402 | S | |
| Allowable business investment loss from line 406 of Schedule 1 | | | T | |
| Subtotal (amount S **plus** amount T) | | 15,375,402 | ▶ | 15,375,402 U |
| Foreign business income after deducting related expenses note 9 | 500 | | | |
| Taxable capital gains from line 113 of Schedule 1 | | 26,660 | V | |
| Net property income (line 032 note 10 **minus** the total of lines 042, 052 and 082 note 9 in Part 1) | | 615,269 | W | |
| Personal services business income after deducting related expenses note 9 | e1 | | | |
| Other income after deducting related expenses note 9 | e2 | | | |
| Subtotal (amount e1 **plus** amount e2) note 9 | ▶ 520 | | | |
| Subtotal (**add** line 500, amount V, amount W and line 520) | | 641,929 | ▶ | 641,929 X |
| Net amount (amount U **minus** amount X) | | | | 14,733,473 Y |
| Partnership income not eligible for the small business deduction (line 450 in Part 5) | | | Z | |
| Partnership income allocated to your corporation under subsection 96(1.1) | 530 | | | |
| Income referred to in clause 125(1)(a)(i)(C) | 540 | | | |
| Income referred to in clause 125(1)(a)(i)(B) (from line 615 in Part 7) | | | AA | |
| Subtotal (**add** amount Z, line 530, line 540 and amount AA) | | | ▶ | BB |
| Specified corporate income (from line 625 in Part 7) | | | | CC |
| **Income eligible for the small business deduction** (amount Y **minus** amount BB, **plus** amount CC) (enter amount DD on line 400 of the T2 return - if negative, enter "0") | | | | 14,733,473 DD |

## Part 7 – Specified corporate income and assignment under subsection 125(3.2)

| | **1EE** Name of the corporation | **EE** Business number of the corporation 600 | **FF** Income described under clause 125(1)(a)(i)(B) received from the corporation identified in column EE note 11 610 | **GG** Business limit assigned **from** the corporation identified in column EE note 12 620 |
|---|---|---|---|---|
| 1 | | | | |
| | | | Total 615 | Total 625 |

See the privacy statement on your return.

## Notes

**Note 1** Do **not** include expenses that were deducted in computing the income of the corporation in column D1.

In general, amounts included under subsections 34.2(2) and 34.2(3) or claimed under subsection 34.2(4) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct only the portion of the following amounts that are characterized as **active business income** in accordance with subsection 34.2(5):

**Add:**
– the ASPA under subsection 34.2(2) (column 4 of Schedule 73)
– the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)
– the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73)

**Deduct:**
– the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)
– the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)

**Note 2** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is **not** netted against the partnership's income when calculating the prorated business limit (column H1). Enter on line 380 the total of all losses from column F1.

**Note 3** **If** you are a **designated member** of the partnership, enter "0".

**Note 4** You must enter "0" **if** the partnership provides services or property to either:

(A) a private corporation (directly or indirectly in any manner whatever) in the year, if:
- you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and
- it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
  - persons (other than the private corporation) that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
  - partnerships with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest, or

(B) a particular partnership (directly or indirectly in any manner whatever) in the year, if:
- you (or one of your shareholders) do **not** deal at arm's length with the particular partnership or a person that holds a direct or indirect interest in the particular partnership, and
- it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
  - persons that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
  - partnerships (other than the particular partnership) with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.

**Note 5** If you are a CCPC that is a **designated member** receiving an assignment of **specified partnership business limit,** complete Table 2 to determine the amounts to enter in Table 1 column I1.

**Note 6** If you are a corporation that is a **member** of the partnership and you are assigning **specified partnership business limit**, complete Table 3 to determine the amounts to enter in Table 1 column J1.

**Note 7** Add the amounts in column H2 that are for the same partnership and enter it in Table 1 column I1, in the row of the applicable partnership.

**Note 8** Add the amounts in column F3 that are for the same partnership and enter it in Table 1 column J1, in the row of the applicable partnership. This amount **cannot** be higher than the amount of prorated business limit you would otherwise be entitled to in Table 1 column H1 for that partnership.

**Note 9** If negative, enter amount in brackets, and **add** instead of subtracting.

**Note 10** Net of related expenses.

**Note 11** This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts, each of which is your income from an active business for the year from providing services or property to a private corporation (directly or indirectly, in any manner whatever) if

(A) at any time in the year, you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and

(B) it is not the case that all or substantially all of your income for the year from an active business is from providing services or property to
(I) persons (other than the private corporation) with which you deal at arm's length, or
(II) partnerships with which you deal at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.

Do **not** include specified farming or fishing income. If the conditions described in subsection 125(10) are met, do not include income from an associated corporation.

**Note 12** The amount of business limit that a CCPC can assign to you cannot be greater than the amount in column FF that is from providing services or property **directly** to that CCPC. If there is an amount included in column FF that is deductible by that CCPC in respect of the amount of its income referred to in clause 125(1)(a)(i)(A) or (B) for its tax year, you need to deduct it from column FF for the purpose of determining the amount that can be assigned to you.

**Notes (continued)**

**Note 13** Active asset, of a particular corporation at any time, means property that is:

(A) used at that time principally in an active business carried on primarily in Canada by the particular corporation or by a Canadian-controlled private corporation that is related to the particular corporation,

(B) a share of the capital stock of another corporation if, at that time,

- the other corporation is connected with the particular corporation (within the meaning assigned by subsection 186(4) on the assumption that the other corporation is at that time a payer corporation within the meaning of that subsection), and
- the share would be a qualified small business corporation share (as defined in subsection 110.6(1)) if:
  – the references in that definition to an "individual" were references to the particular corporation, and
  – that definition were read without reference to "the individual's spouse or common-law partner", or

(C) an interest in a partnership, if:

- at that time, the fair market value of the particular corporation's interest in the partnership is equal to or greater than 10% of the total fair market value of all interests in the partnership,
- throughout the 24-month period ending before that time, more than 50% of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B), and
- at that time, all or substantially all of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B).

**Note 14** Income or loss from property of a particular corporation, for the purposes of calculating the corporation's adjusted aggregate investment income, includes income or loss from a specified investment business, as well as all amounts in respect of a life insurance policy that are included in computing the corporation's income for the year (even if those amounts were not included in the computation of the corporation's aggregate investment income in Part 1).

# Attached Schedule with Total

Foreign investment income – Other property income

Title Other property income

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| T3 - RBC Investor Services Trust | | 0 | 45 |
| T5013 - Brookfield Property Partners LP | + | 106 | 19 |
| T3 - Natcan Trust Company | + | 742 | 63 |
| | + | | |
| | **Total** | 849 | 27 |

**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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**Schedule 8**

# Capital Cost Allowance (CCA)

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

| | 1<br>Class number *<br>See note 1<br>200 | Description | 2<br>Undepreciated capital cost (UCC) at the beginning of the year<br>201 | 3<br>Cost of acquisitions during the year (new property must be available for use)<br>See note 2<br>203 | 4<br>Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP)<br>See note 3<br>225 | 5<br>Adjustments and transfers<br>See note 4<br>205 | 6<br>Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition<br>See note 5<br>221 | 7<br>Amount from column 5 that is repaid during the year for a property, subsequent to its disposition<br>See note 6<br>222 | 8<br>Proceeds of dispositions<br>See note 7<br>207 | For tax years ending before November 21, 2018: 50% rule (1/2 of net acquisitions)<br>211 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 101,330,430 | | | | | | 6,737 | |
| 2. | 8 | | 5,464,533 | 1,186,098 | | | | | 182,871 | |
| 3. | 2 | | 14,544,459 | | | | | | 0 | |
| 4. | 47 | Electrical Trans & Distrib Assets - Feb 23 | 69,060,616 | 8,985,431 | | | | | 86,850 | |
| 5. | 3 | | 1,820,217 | | | | | | 0 | |
| 6. | 45 | | 681 | | | | | | 0 | |
| 7. | 1b | Buildings after March 18, 2007 | 499,813 | 254,050 | | | | | 0 | |
| 8. | 50 | Computer Hardware after March 18, 200 | 1,300,307 | 1,318,704 | | | | | 0 | |
| 9. | 52 | | | | | | | | 0 | |
| 10. | 12 | | 560,539 | 7,785 | | | | | 0 | |
| 11. | 14.1 | | 3,768,108 | | | | | | 0 | |
| 12. | 10 | | | 3,063,725 | | | | | 33,799 | |
| | | **Totals** | 198,349,703 | 14,815,793 | | | | | 310,257 | |

| | 1<br>Class number *<br>See note 1<br>200 | Des-crip-tion | 9<br>UCC<br>(column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8)<br>See note 8 | 10<br>Proceeds of disposition available to reduce the UCC of AIIP (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0") | 11<br>Net capital cost additions of AIIP acquired during the year (column 4 **minus** column 10) (if negative, enter "0") | 12<br>UCC adjustment for AIIP acquired during the year (column 11 **multiplied** by the relevant factor)<br>See note 9 | 13<br>UCC adjustment for non-AIIP acquired during the year (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")<br>See note 10<br>224 | 14<br>CCA rate %<br>See note 11<br>212 | 15<br>Recapture of CCA<br>See note 12<br>213 | 16<br>Terminal loss<br>See note 13<br>215 | 17<br>CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount)<br>See note 14<br>217 | 18<br>UCC at the end of the year (column 9 **minus** column 17)<br>220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 101,323,693 | | | | | 4 | 0 | 0 | 4,052,948 | 97,270,745 |
| 2. | 8 | | 6,467,760 | | | | 501,614 | 20 | 0 | 0 | 1,193,229 | 5,274,531 |
| 3. | 2 | | 14,544,459 | | | | | 6 | 0 | 0 | 872,668 | 13,671,791 |
| 4. | 47 | Electric | 77,959,197 | | | | 4,449,291 | 8 | 0 | 0 | 5,880,792 | 72,078,405 |
| 5. | 3 | | 1,820,217 | | | | | 5 | 0 | 0 | 91,011 | 1,729,206 |
| 6. | 45 | | 681 | | | | | 45 | 0 | 0 | 306 | 375 |
| 7. | 1b | Buildin | 753,863 | | | | 127,025 | 6 | 0 | 0 | 37,610 | 716,253 |
| 8. | 50 | Compu | 2,619,011 | | | | 659,352 | 55 | 0 | 0 | 1,077,812 | 1,541,199 |
| 9. | 52 | | | | | | | 100 | 0 | 0 | | |
| 10. | 12 | | 568,324 | | | | 3,893 | 100 | 0 | 0 | 564,431 | 3,893 |
| 11. | 14.1 | | 3,768,108 | | | | | 5 | 0 | 0 | 263,767 | 3,504,341 |
| 12. | 10 | | 3,029,926 | | | | 1,514,963 | 30 | 0 | 0 | 454,489 | 2,575,437 |
| | | **Totals** | 212,855,239 | | | | 7,256,138 | | | | 14,489,063 | 198,366,176 |

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

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. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use. 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. An accelerated investment incentive property (AIIP) is a property (other than property included in Class 54 or 55) that you acquired after November 20, 2018 and became available for use before 2028. See the T2 Corporation Income Tax Guide for more information. Classes 54 and 55 include property that is a zero-emission vehicle you acquired after March 18, 2019 and became available for use before 2028.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost (column 9). Items that increase the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the undepreciated capital cost (show amounts that reduce the undepreciated capital cost in brackets) include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.

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 year 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 the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or 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 tax year.

Note 7. For each property disposed of during the year, 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).

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for AIIP of a class in Schedule II and for property included in classes 54 and 55, available for use before 2024, are:

- 2 1/3 for property in Classes 43.1 and 54;
- 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 non-AIIP acquired during the year (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). 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 tax year and there is still a positive amount in the 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.

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year 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 tax year (before any CCA deduction).
- Class 14: the lesser of 150% of the allocation for the year 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 a the end of the tax year (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 tax year and the UCC at the end of the tax year (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 tax year (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.
- Property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit: 150% of the amount determined by first subtracting the total of the residual value of the timber limit and all amounts you expended for the 1949 or later tax years for surveys, cruises or preparation of prints, maps or plans for the purpose of obtaining a licence or right to cut timber from the capital cost of the limit or right, and then dividing the result by the quantity of timber in the limit or the quantity of timber you have the right to cut.
- Industrial mineral mine or a right to remove industrial minerals from an industrial mineral mine: 150% of the amount determined by first subtracting the residual value, if any, of the mine or right from the capital cost of the mine or right, and then dividing the result by the number of units of commercially mineable material estimated to be in the mine when the mine or right was acquired (alternatively, if you have acquired a right to remove only a specified number of units, that number of units that you acquired a right to remove).

# Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

## Tax return

| | | | | |
|---|---|---|---|---|
| Additions for tax purposes – Schedule 8 regular classes | | 14,815,793 | | |
| Additions for tax purposes – Schedule 8 leasehold improvements | + | | | |
| Operating leases capitalized for book purposes | + | | | |
| Capital gain deferred | + | | | |
| Recapture deferred | + | | | |
| Deductible expenses capitalized for book purposes – Schedule 1 | + | | | |
| Other (specify): | | | | |
| CIP Increase (Decrease) | + | -1,121,680 | | |
| Contributed capital booked to deferred revenue | + | 2,325,435 | | |
| Capitalized labour expensed for SRED purposes (software) | + | 309,886 | | |
| ACB of land | + | 3,493 | | |
| Prior period pole depreciation adjustment | + | | | |
| Capitalized overhead and burden expensed | + | 1,832,553 | | |
| Replacement poles | + | 1,580,503 | | |
| Rounding | + | 2 | | |
| **Total additions per books** | = | 19,745,985 | ▶ | 19,745,985 |
| Proceeds up to original cost – Schedule 8 regular classes | | 310,257 | | |
| Proceeds up to original cost – Schedule 8 leasehold improvements | + | | | |
| Proceeds in excess of original cost – capital gain | + | 30,252 | | |
| Recapture deferred – as above | + | | | |
| Capital gain deferred – as above | + | | | |
| Pre V-day appreciation | + | | | |
| Other (specify): | | | | |
| Land Portion of Class 1 Substain disposals See W/P SS6.3 & SS6.5 | + | 19,176 | | |
| Depreciation on contributed capital (AC#606245) | + | 353,872 | | |
| Prior year burden re wood pools | + | | | |
| Prior year depreciation adjustment | + | | | |
| Rounding | + | | | |
| Overhead adjustment related to burdens and poles | + | 150,688 | | |
| **Total proceeds per books** | = | 864,245 | ▶ – | 864,245 |
| Depreciation and amortization per accounts – Schedule 1 | | | – | 13,655,154 |
| Loss on disposal of fixed assets per accounts | | | – | 361,159 |
| Gain on disposal of fixed assets per accounts | | | + | |
| **Net change per tax return** | | | = | 4,865,427 |

## Financial statements

**Fixed assets (excluding land) per financial statements**

| | | |
|---|---|---|
| Closing net book value | | 233,131,702 |
| Opening net book value | – | 228,266,275 |
| **Net change per financial statements** | = | 4,865,427 |

If the amounts from the tax return and the financial statements differ, explain why below.

# Attached Schedule with Total

Other – Amount

Title Other – Amount

| Description | Operator (Note) | Amount |
|---|---|---|
| Class 47 | | 2,317,960 00 |
| Class 8 | + | 7,475 00 |
| | + | |
| | **Total** | 2,325,435 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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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Enwin Energy Ltd. | | 88246 2526 RC0001 | 3 | | | | | |
| 2. | Windsor Canada Utilities Ltd. | | 86712 9181 RC0001 | 1 | | | | | |
| 3. | Corporation of the City of Windsor | | NR | 3 | | | | | |
| 4. | Enwin Financial Services Ltd. | | 83435 7147 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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**SCHEDULE 13**

# CONTINUITY OF RESERVES

| Name of corporation | Business number | Tax year end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

## Part 1 – Capital gains reserves

| | Description of property 001 | Balance at the beginning of the year $ 002 | Transfer on an amalgamation or the wind-up of a subsidiary $ 003 | Add $ | Deduct $ | Balance at the end of the year $ 004 |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| | **Totals** | 008 | 009 | | | 010 |

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

## Part 2 – Other reserves

| Description | | Balance at the beginning of the year $ | Transfer on an amalgamation or the wind-up of a subsidiary $ | Add $ | Deduct $ | Balance at the end of the year $ |
|---|---|---|---|---|---|---|
| Reserve for doubtful debts | X | 110 1,038,077 | 115 | 985,066 | 1,038,077 | 120 985,066 |
| Reserve for undelivered goods and services not rendered | | 130 | 135 | | | 140 |
| Reserve for prepaid rent | | 150 | 155 | | | 160 |
| Reserve for refundable containers | | 190 | 195 | | | 200 |
| Reserve for unpaid amounts | | 210 | 215 | | | 220 |
| Other tax reserves | | 230 | 235 | | | 240 |
| **Totals** | | 270 1,038,077 | 275 | 985,066 | 1,038,077 | 280 985,066 |

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | Post-retirement benefits | 68,392,400 | | 64,397,300 | 68,392,400 | 64,397,300 |
| 2 | Obsolete inventory reserve | 996,870 | | 794,786 | 996,870 | 794,786 |
| 3 | Accrued unpaid salary continua | 69,671 | | | 69,671 | |
| 4 | Accrued bonuses | 29,428 | | | 29,428 | |
| 5 | WUC receivable for post-retiren | -2,876,870 | | -2,054,765 | -2,876,870 | -2,054,765 |
| 6 | Cogeco | 100,000 | | 100,000 | 100,000 | 100,000 |
| 7 | Essex Condo Lawsuit | | | 25,000 | | 25,000 |
| 8 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | 1,038,077 | | 985,066 | 1,038,077 | 985,066 |
| | **Totals** | 67,749,576 | | 64,247,387 | 67,749,576 | 64,247,387 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**Schedule 21**

# Federal and Provincial or Territorial Foreign Income Tax Credits and Federal Logging Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Corporations resident in Canada at any time in the year and authorized foreign banks can use this schedule to claim a federal foreign non-business income tax credit, a federal foreign business income tax credit, or a provincial or territorial foreign non-business income tax credit.
- Corporations can use this schedule to claim a federal logging tax credit.
- Calculate the foreign income tax credits for each country separately. Attach another schedule if the corporation is claiming credits for more than five countries.
- Calculate the provincial/territorial foreign non-business income tax credits for each country and province or territory separately.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.

## Part 1 – Federal foreign non-business income tax credit

| | A<br>Country of source of foreign non-business income<br>100 | B<br>Net foreign non-business income earned in the year *<br>110 | C<br>Foreign non-business income tax paid for the year **<br>120 | D<br>Foreign non-business income tax paid, deducted from income under subsection 20(12)<br>130 | E<br>(C – D) |
|---|---|---|---|---|---|
| 1. | US | 849 | 88 | | 88 |
| 2. | | | | | |

| | F<br>Adjusted net income (amount from line 600 in Part 6) | G<br>Part I tax otherwise payable (amount from line 610 in Part 7) | H<br>(B x G) ÷ F (amount in column H cannot be more than amount in column G) | I<br>Deductible credit: lesser of amounts E or H<br>180 |
|---|---|---|---|---|
| 1. | 15,370,145 | 4,369,620 | 241 | 88 |
| 2. | 15,370,145 | 4,369,620 | | |
| | | | **Total deductible federal foreign non-business income tax credit** | 88 |

Enter the total deductible federal foreign non-business income tax credit, or a lesser amount, on line 632 of the T2 return.

* Exclude income that is exempt from tax in Canada under an income tax treaty, dividends received from foreign affiliates, and tax-exempt income as defined in subsection 126(7). Net foreign non-business income is the excess of qualifying income over qualifying losses, which are determined according to subsection 126(9).

** Exclude taxes paid to a foreign government on income that is exempt from tax in Canada under an income tax treaty; foreign taxes paid on dividends received from foreign affiliates; and any foreign taxes that may reasonably be regarded as relating to an amount that any other person or partnership has received, or is entitled to receive, from that government.

Exclude taxes paid for property (other than capital property) from which the corporation is not expected to realize a profit.

Exclude taxes paid that are in excess of the limit and paid for dividends and interest on a share or debt obligation held for one year or less.

Exclude taxes attributable to amounts received or receivable for eligible loans.

## Part 2 – Federal foreign business income tax credit

| | A<br>Country in which foreign business income was earned<br>200 | B<br>Net foreign business income earned in the year *<br>210 | C<br>Foreign business income tax paid for the year **<br>220 | D<br>Unused foreign income tax credits from previous tax years<br>230 | E<br>Total of columns C and D |
|---|---|---|---|---|---|
| 1. | | | | | |

| | F<br>Adjusted net income (amount from line 600 in Part 6) | G<br>Part I tax otherwise payable (amount from line 620 in Part 8) | H<br>Part I tax otherwise payable minus foreign non-business income tax credits claimed | I<br>(B x G) ÷ F | J<br>Deductible credit: the least of amounts E, H, or I<br>280 |
|---|---|---|---|---|---|
| 1. | 15,370,145 | 3,923,579 | 3,923,491 | | |
| | | | | **Total deductible federal foreign business income tax credit** | |

Enter the total deductible federal foreign business income tax credit, or a lesser amount, on line 636 of the T2 return.

* Exclude income that is exempt from tax in Canada under an income tax treaty and tax-exempt income as defined in subsection 126(7). Net foreign business income is the excess of qualifying income over qualifying losses, which are determined according to subsection 126(9).

** Exclude taxes paid to a foreign government on income that is exempt from tax in Canada under an income tax treaty. Also exclude any foreign taxes that may reasonably be regarded as relating to an amount that any other person or partnership has received or is entitled to receive from that government.

Exclude taxes paid for property (other than capital property) from which the corporation is not expected to realize a profit.

Exclude taxes paid that are in excess of the limit and paid for dividends and interest on a share or debt obligation held for one year or less.

## Part 3 – Continuity of unused federal foreign business income tax credits

| | K<br>Country in which foreign business income was earned<br>345 | L<br>Balance at end of the previous tax year | M ***<br>Amount expired in the year<br>348 | N<br>Opening balance (L – M)<br>350 | O<br>Credits transferred on an amalgamation or the wind-up of a subsidiary<br>360 |
|---|---|---|---|---|---|
| 1. | | | | | |

*** An unused federal foreign business income tax credit expires as follows:
- after 7 tax years if it was earned in a tax year ending before March 23, 2004; or
- after 10 tax years if it was earned in a tax year ending after March 22, 2004.

| | P<br>Foreign business income tax paid for the year (from column C of Part 2) | Q<br>Foreign business income tax credit deductible in the year (cannot be more than the amount in column J of Part 2) | R<br>Carryback to previous years (total of amounts in columns V, W, and X of Part 4) | S<br>Closing balance (N + O + P – Q – R)<br>380 |
|---|---|---|---|---|
| 1. | | | | |

## Part 4 – Request for a federal foreign business income tax credit carryback

| | T<br>Country in which foreign business income was earned<br>900 | U<br>Unused foreign business income tax credit (Part 3, (P – Q)) | V<br>Carryback to 1st previous tax year *<br>901 | W<br>Carryback to 2nd previous tax year *<br>902 | X<br>Carryback to 3rd previous tax year *<br>903 |
|---|---|---|---|---|---|
| 1. | | | | | |

* Total of carryback (amounts from columns V, W, and X) cannot be more than the unused foreign business income tax credit (amount from column U).

## Part 5 – Federal logging tax credit

| A Province | B Income from logging under Regulation 700 | C Amount B X 6 2/3% | D Logging tax paid on income in column B | E Amount D X 2/3 | F Lesser of amounts C or E |
|---|---|---|---|---|---|
| British Columbia | 500 | | 510 | | |
| Quebec | 520 | | 530 | | |
| | | | | Total | G |

6 2/3% of taxable income (or, for non-residents, 6 2/3% of taxable income earned in Canada) . . . 1,024,216 H

**Federal logging tax credit** – Lesser of amounts G and H . . . 580 ______ I

Enter amount I or a lesser amount on line 640 of the T2 return.

## Part 6 – Adjusted net income

Line references are from T2 return.

**To be completed by all corporations other than an authorized foreign bank**

| | | |
|---|---|---|
| Net income for income tax purposes (line 300) (if negative, enter "0") | 15,375,402 | |
| **Deduct:** | | |
| Net capital losses claimed under paragraph 111(1)(b) (line 332) | | |
| Taxable dividends deductible under sections 112 and 113 | 5,257 | |
| Amount deductible under paragraph 110(1)(d.2) for prospector's and grubstaker's shares (line 350) | | |
| Subtotal (if negative, enter "0") | 15,370,145 ▶ | 15,370,145 |
| **Add:** Amount added to taxable income for foreign tax deductions under section 110.5 (line 355) | | |
| Total | | 15,370,145 A |

**To be completed by an authorized foreign bank only**

| | | |
|---|---|---|
| Taxable income earned in Canada (line 360) (if negative, enter "0") | | B |
| Income from its Canadian banking business (line 300) (if negative, enter "0") | | |
| **Add:** Amount added to taxable income for foreign tax deductions under subparagraph 115(1)(a)(vii) (line 355) | | |
| Subtotal | ▶ | C |
| Amount B or C, whichever is less | | D |
| **Adjusted net income** (amount A or D, whichever is applicable) | 600 | 15,370,145 |

If you need more space, continue on a separate schedule.

## Part 7 – Part I tax otherwise payable (foreign non-business income tax credit)

Line references are from T2 return.

| | | |
|---|---|---|
| Base amount of Part I tax (line 550) | | 5,838,033 A |
| **Deduct:** | | |
| Federal tax abatement (line 608) | 1,536,325 | |
| Investment corporation deduction (line 620) | | |
| Additional deduction for credit unions (line 628) | | |
| General tax reduction (line 639) | | |
| Subtotal | 1,536,325 ▶ | 1,536,325 B |
| **Add:** | | |
| Recapture of investment tax credit (line 602) | | |
| Refundable tax on Canadian-controlled private corporation's (CCPC) investment income (line 604) | 67,912 | |
| Subtotal | 67,912 ▶ | 67,912 C |
| **Part I tax otherwise payable (foreign non-business income tax credit)** (amount A **minus** amount B **plus** amount C) | 610 | 4,369,620 |

## Part 8 – Part I tax otherwise payable (foreign business income tax credit)

Line references are from T2 return.

| | | | |
|---|---|---|---|
| Base amount of Part I tax (line 550) | | 5,838,033 | A |
| **Deduct:** | | | |
| Investment corporation deduction (line 620) | | | |
| Additional deduction for credit unions (line 628) | | | |
| General tax reduction for CCPCs (line 638) | 1,914,454 | | |
| General tax reduction (line 639) | | | |
| Subtotal | 1,914,454 ▶ | 1,914,454 | B |
| **Add**: Recapture of investment tax credit (line 602) | | | C |
| **Part I tax otherwise payable (foreign business income tax credit)** (amount A **minus** amount B **plus** amount C) | 620 | 3,923,579 | |

## Summary per country for unused foreign business income tax credits

Country name:

| Year of origin (Year / Month / Day) | Opening balance | Current year foreign income tax paid | Transfers | Applied | Balance to carry forward |
|---|---|---|---|---|---|
| | * | | | | N/A |
| | | | | | ** |

* Note that this credit has now expired and will be posted to line 348 in Part 3 of Schedule 21.

** Note that this credit expires at the end of the tax year and any expired credit will be posted to line 348 in Part 3 of Schedule 21 the following year.

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**Schedule 23**

# Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

**Column 2:** Provide the business number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)

2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation

3 – Non-CCPC that is a **third corporation**

4 – Associated non-CCPC

5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

**Column 4:** Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . . . . . **050** Year 2018

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . . . **075** ☐ Yes ☒ No

| | 1<br>Name of associated corporations<br>**100** | 2<br>Business number of associated corporations<br>**200** | 3<br>Association code<br>**300** | 4<br>Business limit for the year before the allocation<br>$ | 5<br>Percentage of the business limit<br>%<br>**350** | 6<br>Business limit allocated*<br>$<br>**400** |
|---|---|---|---|---|---|---|
| 1 | Enwin Utilities Ltd. | 86712 0586 RC0002 | 1 | 500,000 | 100.0000 | 500,000 |
| 2 | Enwin Energy Ltd. | 88246 2526 RC0001 | 1 | 500,000 | | |
| 3 | Windsor Canada Utilities Ltd. | 86712 9181 RC0001 | 1 | 500,000 | | |
| 4 | Corporation of the City of Windsor | NR | 1 | | | |
| 5 | Enwin Financial Services Ltd. | 83435 7147 RC0001 | 1 | 500,000 | | |
| | | | | **Total** | 100.0000 | 500,000 A |

**Business limit reduction under subsection 125(5.1) of the Act**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

**Special rules for business limit**

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

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**Schedule 31**

# Investment Tax Credit – Corporations

## General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years;
  - if you are subject to a recapture of ITC; or
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**;
    - the **Ontario Innovation Tax Credit.**
- Unless otherwise stated, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the investment tax credit. If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.
- File this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide* and read Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see guide T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

## Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the *Oceans Act* (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

## Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

## Part 1 – Investments, expenditures, and percentages

| | Specified percentage |
|---|---|
| **Investments** | |
| Qualified property acquired primarily for use in Atlantic Canada | 10 % |
| Qualified resource property acquired primarily for use in Atlantic Canada and acquired: | |
| – after March 28, 2012, and before 2014 | 10 % |
| – after 2013 and before 2016 | 5 % |
| – after 2015* | 0 % |
| **Expenditures** | |
| If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) | 35 % |
| **Note:** If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate. | |
| If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada: | |
| – before 2014** | 20 % |
| – after 2013** | 15 % |
| If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012 | 10 % |
| If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures: | |
| – after March 28, 2012, and before 2013 | 10 % |
| – in 2013 | 5 % |
| – after 2013 | 0 % |
| If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***: | |
| – after March 28, 2012, and before 2014 | 10 % |
| – in 2014 | 7 % |
| – in 2015 | 4 % |
| – after 2015 | 0 % |
| If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment | 10 % |
| If you incurred expenditures after March 18, 2007 and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children | 25 % |

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

## Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

**Note:** A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

## Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **103** ________
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

# Qualified Property and Qualified Resource Property

## Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

| Capital cost allowance class number **105** | Description of investment **110** | Date available for use **115** | Location used in Atlantic Canada (province) **120** | Amount of investment **125** |
|---|---|---|---|---|
| | | | | |

**Total of investments for qualified property and qualified resource property** ________ A1

## Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | B1 |
| Credit deemed as a remittance of co-op corporations | 210 | | | |
| Credit expired | 215 | | | |
| Subtotal (line 210 **plus** line 215) | | | ▶ | C1 |
| ITC at the beginning of the tax year (amount B1 **minus** amount C1) | | | 220 | |
| Credit transferred on an amalgamation or the wind-up of a subsidiary | 230 | | | |
| ITC from repayment of assistance | 235 | | | |
| Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % = | 240 | | | |
| Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % = | 242 | | | |
| Credit allocated from a partnership | 250 | | | |
| Subtotal (total of lines 230 to 250) | | | ▶ | D1 |
| Total credit available (line 220 **plus** amount D1) | | | | E1 |
| Credit deducted from Part I tax | 260 | | | |
| Credit carried back to previous years (amount H1 in Part 6) | | | a | |
| Credit transferred to offset Part VII tax liability | 280 | | | |
| Subtotal (total of line 260, amount a, and line 280) | | | ▶ | F1 |
| Credit balance before refund (amount E1 **minus** amount F1) | | | | G1 |
| Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) | | | 310 | |
| **ITC closing balance of investments from qualified property and qualified resource property** (amount G1 **minus** line 310) | | | 320 | |

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

## Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 901 | |
| 2nd previous tax year | | | | Credit to be applied | 902 | |
| 3rd previous tax year | | | | Credit to be applied | 903 | |
| | | | | Total of lines 901 to 903<br>Enter at amount a in Part 5. | | H1 |

## Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

| | |
|---|---|
| Current-year ITCs (total of lines 240, 242, and 250 in Part 5) | I1 |
| Credit balance before refund (from amount G1 in Part 5) | J1 |
| **Refund** ( 40 % of amount I1 or J1, whichever is less) | K1 |

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

## SR&ED

### Part 8 – Qualified SR&ED expenditures

| | | | | |
|---|---|---|---|---|
| Current expenditures (from line 557 on Form T661) | | 506,564 | | |
| Contributions to agricultural organizations for SR&ED | | | | |
| **Deduct:** | | | | |
| Government assistance, non-government assistance, or contract payment | | | | |
| Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* | | ► + | | |
| Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)* | | 506,564 ► | 350 | 506,564 |
| Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** | | | 360 | |
| Repayments made in the year (from line 560 on Form T661) | | | 370 | |
| **Qualified SR&ED expenditures** (total of lines 350 to 370) | | | 380 | 506,564 |

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

### Part 9 – Components of the SR&ED expenditure limit calculation

**Part 9 only applies if you are a CCPC.**

**Note:** A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . . . **385** 1 Yes [X] 2 No [ ]

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

| | | |
|---|---|---|
| Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) | 390 | |
| Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million | 398 | |

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

### Part 10 – SR&ED expenditure limit for a CCPC

| | | | | |
|---|---|---|---|---|
| **For a stand-alone (not associated) corporation:** | | | $ 8,000,000 | |
| Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more | | x 10 = | | A2 |
| Excess ($8,000,000 **minus** amount A2 if the taxation year ends before March 19, 2019; otherwise, enter $3,000,000) (if negative, enter "0")* | | | | B2 |
| $ 40,000,000 **minus** line 398 in Part 9 | | b | | |
| Amount b **divided** by $ 40,000,000 | | | | C2 |
| **Expenditure limit for the stand-alone corporation** (amount B2 **multiplied** by amount C2)** | | | | D2 |
| **For an associated corporation:** | | | | |
| If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49** | | 400 | | E2 |
| **If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:** | | | | |
| Amount D2 or E2 | x Number of days in the tax year / 365 | 365 = | | F2 |
| **Your SR&ED expenditure limit for the year** (enter amount D2, E2, or F2, whichever applies) | | 410 | | |

* For taxation years ending after March 18, 2019, the taxable income is no longer taken into account in the SR&ED expenditure limit calculation. For more information, consult the Help (F1).

** Amount D2 or E2 cannot be more than $3,000,000.

## Part 11 – Investment tax credits on SR&ED expenditures

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* | **420** | | x | 35 % | = | | G2 |
| Line 350 **minus** line 410 (if negative, enter "0") | **430** | 506,564 | | | | | |

Amount from line 430 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ c

Amount from line 430** 506,564 x (Number of days in the tax year after 2013 365 / Number of days in the tax year 365) x 15 % = 75,985 d

| | | | | |
|---|---|---|---|---|
| Subtotal (amount c **plus** amount d) | 75,985 | ▶ | 75,985 | H2 |
| Line 410 **minus** line 350 (if negative, enter "0") | | e | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Capital expenditures (line 360 in Part 8) or amount e, whichever is less* | **440** | | x | 35 % | = | | I2 |
| Line 360 **minus** amount e (if negative, enter "0") | **450** | | | | | | |

Amount from line 450 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ f

Amount from line 450** ______ x (Number of days in the tax year after 2013 365 / Number of days in the tax year 365) x 15 % = ______ g

Subtotal (amount f **plus** amount g) ______ ▶ ______ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

**Repayments** (amount from line 370 in Part 8) ______

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Repayment of assistance that reduced a qualifying expenditure for a CCPC*** | **460** | | x | 35 % | = | | h |
| Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015 | **480** | | x | 20 % | = | | i |
| Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014 | **490** | | x | 15 % | = | | j |

Subtotal (**add** amounts h to j) ______ ▶ ______ K2

**Current-year SR&ED ITC** (total of amounts G2 to K2; enter on line 540 in Part 12) 75,985 L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start **before** 2014, the reduction is pro-rated based on the number of days in the tax year that are **after** 2013. For tax years that have a start date **after** 2013, **multiply** the amount by 15%.

*** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

## Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | | M2 |
| Credit deemed as a remittance of co-op corporations | 510 | | | | |
| Credit expired | 515 | | | | |
| Subtotal (line 510 **plus** line 515) | | | ▶ | | N2 |
| ITC at the beginning of the tax year (amount M2 **minus** amount N2) | | | 520 | | |
| Credit transferred on an amalgamation or the wind-up of a subsidiary | 530 | | | | |
| Total current-year credit (from amount L2 in Part 11) | 540 | 75,985 | | | |
| Credit allocated from a partnership | 550 | | | | |
| Subtotal (total of lines 530 to 550) | | 75,985 | ▶ | 75,985 | O2 |
| Total credit available (line 520 **plus** amount O2) | | | | 75,985 | P2 |
| Credit deducted from Part I tax | 560 | 75,985 | | | |
| Credit carried back to previous years (amount S2 in Part 13) | | | k | | |
| Credit transferred to offset Part VII tax liability | 580 | | | | |
| Subtotal (total of line 560, amount k, and line 580) | | 75,985 | ▶ | 75,985 | Q2 |
| Credit balance before refund (amount P2 **minus** amount Q2) | | | | | R2 |
| Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) | | | 610 | | |
| **ITC closing balance on SR&ED** (amount R2 **minus** line 610) | | | 620 | | |

## Part 13 – Request for carryback of credit from SR&ED expenditures

| | Year | Month | Day | | Line | Amount | |
|---|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 911 | | |
| 2nd previous tax year | | | | Credit to be applied | 912 | | |
| 3rd previous tax year | | | | Credit to be applied | 913 | | |
| | | | | Total of lines 911 to 913<br>Enter at amount k in Part 12. | | | S2 |

## Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

| | | | |
|---|---|---|---|
| Is the corporation an excluded corporation as defined under subsection 127.1(2)? | 650 | 1 Yes [ ] 2 No [X] | |
| Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) | | | I |
| Refundable credits (amount I or amount R2 in Part 12, whichever is less)* | | | T2 |
| Amount T2 or amount G2 in Part 11, whichever is less | | | U2 |
| Net amount (amount T2 **minus** amount U2; if negative, enter "0") | | | V2 |
| Amount V2 **multiplied** by 40 % | | | W2 |
| Amount U2 | | | X2 |
| **Refund of ITC** (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) | | | Y2 |

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

## Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

| | | |
|---|---|---|
| Credit balance before refund (amount R2 in Part 12) | | Z2 |
| Amount Z2 or amount G2 in Part 11, whichever is less | | AA2 |
| Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") | | BB2 |
| Amount BB2 or amount I2 in Part 11, whichever is less | | CC2 |
| Amount CC2 **multiplied** by 40 % | | DD2 |
| Amount AA2 | | EE2 |
| **Refund of ITC** (amount DD2 **plus** amount EE2) | | FF2 |

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

# Recapture – SR&ED

## Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

**Note:**

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

### Calculation 1 – If you meet all of the above conditions

| Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above<br>700 | Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case)<br>710 | Amount from column 700 or 710, whichever is less |
|---|---|---|
| | | |

**Subtotal** Enter at amount C3 in Part 17. A3

### Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

| A<br>Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement<br>720 | B<br>Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition<br>730 | C<br>Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.)<br>740 | D<br>Amount determined by the formula (A x B) – C | E<br>ITC earned by the transferee for the qualified expenditures that were transferred<br>750 | F<br>Amount from column D or E, whichever is less |
|---|---|---|---|---|---|
| | | | | | |

**Subtotal** (total of column F) Enter at amount D3 in Part 17. B3

## Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

### Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ______
Enter at amount E3 in Part 17.

## Part 17 – Total recapture of SR&ED investment tax credit

| | | |
|---|---|---|
| Recaptured ITC from calculation 1, amount A3 in Part 16 | | C3 |
| Recaptured ITC from calculation 2, amount B3 in Part 16 | | D3 |
| Recaptured ITC from calculation 3, line 760 in Part 16 | | E3 |
| **Total recapture of SR&ED investment tax credit** (total of amounts C3 to E3)<br>Enter at amount A8 in Part 29. | | F3 |

# Pre-Production Mining

## Part 18 – Pre-production mining expenditures

### Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

| List of minerals 800 | Project name 805 |
|---|---|
| | |

| Mineral title 806 | Mining division 807 |
|---|---|
| | |

### Pre-production mining expenditures*

**Exploration:**

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting . . . . . . . . . . 810 ______

Geological, geophysical, or geochemical surveys . . . . . . . . . . 811 ______

Drilling by rotary, diamond, percussion, or other methods . . . . . . . . . . 812 ______

Trenching, digging test pits, and preliminary sampling . . . . . . . . . . 813 ______

**Development:**

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping . . . . . . . . . . 820 ______

Sinking a mine shaft, constructing an adit, or other underground entry . . . . . . . . . . 821 ______

Other pre-production mining expenditures incurred in the tax year:

| Description 825 | Amount 826 |
|---|---|
| | |

Total of column 826 ______ ► ______ A4

Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) . . . . . . . . . . 830 ______

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above . . . . . . . . . . 832 ______

Excess (line 830 **minus** line 832) (if negative, enter "0") . . . . . . . . . . ______ B4

Repayments of government and non-government assistance . . . . . . . . . . 835 ______

**Pre-production mining expenditures** (amount B4 **plus** line 835) . . . . . . . . . . ______ C4

* A pre-production mining expenditure is defined under subsection 127(9).

## Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | D4 |
| Credit deemed as a remittance of co-op corporations | 841 | | | |
| Credit expired | 845 | | | |
| Subtotal (line 841 **plus** line 845) | | | ▶ | E4 |
| ITC at the beginning of the tax year (amount D4 **minus** amount E4) | | | 850 | |
| Credit transferred on an amalgamation or the wind-up of a subsidiary | | | 860 | |
| Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18) | 870 | x 10 % = | | m |
| Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18) | 872 | x 5 % = | | n |
| Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18) | 874 | x 7 % = | | o |
| Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18) | 876 | x 4 % = | | p |
| Current year credit (total of amounts m to p) | 880 | | ▶ | F4 |
| Total credit available (total of lines 850, 860, and amount F4) | | | | G4 |
| Credit deducted from Part I tax | 885 | | | |
| Credit carried back to previous years (amount I4 in Part 20) | | | | q |
| Subtotal (line 885 **plus** amount q) | | | ▶ | H4 |
| **ITC closing balance from pre-production mining expenditures** (amount G4 **minus** amount H4) | | | 890 | |

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in subparagraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

## Part 20 – Request for carryback of credit from pre-production mining expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 921 | |
| 2nd previous tax year | | | | Credit to be applied | 922 | |
| 3rd previous tax year | | | | Credit to be applied | 923 | |
| | | | | Total of lines 921 to 923<br>Enter at amount q in Part 19. | | I4 |

### Apprenticeship Job Creation

## Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 |
|---|---|---|---|---|---|
| 1. | CA4154 | Powerline Technician | 26,476 | 2,648 | 2,000 |
| 2. | CA4153 | Powerline Technician | 25,405 | 2,541 | 2,000 |

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 |
|---|---|---|---|---|---|
| 3. | CA4152 | Powerline Technician | 28,669 | 2,867 | 2,000 |
| 4. | SYS035456 | Powerline Technician | 59,875 | 5,988 | 2,000 |
| 5. | SYS035454 | Powerline Technician | 61,740 | 6,174 | 2,000 |
| 6. | SYS036386 | Powerline Technician | 70,448 | 7,045 | 2,000 |
| 7. | SYS070659 | Powerline Technician | 26,521 | 2,652 | 2,000 |
| 8. | SYS072051 | Powerline Technician | 26,075 | 2,608 | 2,000 |
| | | | | Total current-year credit (total of column E)<br>Enter on line 640 in Part 22. | 16,000 A5 |

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

## Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

| | | | |
|---|---|---|---|
| ITC at the end of the previous tax year | | | B5 |
| Credit deemed as a remittance of co-op corporations | 612 | | |
| Credit expired after 20 tax years | 615 | | |
| Subtotal (line 612 **plus** line 615) | | ▶ | C5 |
| ITC at the beginning of the tax year (amount B5 **minus** amount C5) | 625 | | |
| Credit transferred on an amalgamation or the wind-up of a subsidiary | 630 | | |
| ITC from repayment of assistance | 635 | | |
| Total current-year credit (amount A5 in Part 21) | 640 | 16,000 | |
| Credit allocated from a partnership | 655 | | |
| Subtotal (total of lines 630 to 655) | | 16,000 ▶ | 16,000 D5 |
| Total credit available (line 625 **plus** amount D5) | | | 16,000 E5 |
| Credit deducted from Part I tax | 660 | 16,000 | |
| Credit carried back to previous years (amount G5 in Part 23) | | r | |
| Subtotal (line 660 **plus** amount r) | | 16,000 ▶ | 16,000 F5 |
| **ITC closing balance from apprenticeship job creation expenditures** (amount E5 **minus** amount F5) | 690 | | |

## Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 931 | |
| 2nd previous tax year | | | | Credit to be applied | 932 | |
| 3rd previous tax year | | | | Credit to be applied | 933 | |
| | | | | Total of lines 931 to 933<br>Enter at amount r in Part 22. | | G5 |

# Child Care Spaces

## Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007 and before March 22, 2017* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

### Cost of depreciable property from the current tax year

| | Capital cost allowance class number<br>665 | Description of investment<br>675 | Date available for use<br>685 | Amount of investment<br>695 |
|---|---|---|---|---|
| 1. | | | | |

Total cost of depreciable property from the current tax year (total of column 695) **715** ______

Specified child care start-up expenditures from the current tax year . . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A6

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . ______ B6

Repayments by the corporation of government and non-government assistance . . . . . **735** ______

**Total eligible expenditures for child care spaces** (amount B6 **plus** line 735) . . . . . **745** ______

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

## Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . . **755** ______ x $ 10,000 = ______ D6

**ITC from child care spaces expenditures** (amount C6 or D6, whichever is less) . . . . . ______ E6

## Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

| | | | |
|---|---|---|---|
| ITC at the end of the previous tax year | | | F6 |
| Credit deemed as a remittance of co-op corporations | 765 | | |
| Credit expired after 20 tax years | 770 | | |
| Subtotal (line 765 **plus** line 770) | | ▶ | G6 |
| ITC at the beginning of the tax year (amount F6 **minus** amount G6) | | 775 | |
| Credit transferred on an amalgamation or the wind-up of a subsidiary | 777 | | |
| Total current-year credit (amount E6 in Part 25) | 780 | | |
| Credit allocated from a partnership | 782 | | |
| Subtotal (total of lines 777 to 782) | | ▶ | H6 |
| Total credit available (line 775 **plus** amount H6) | | | I6 |
| Credit deducted from Part I tax | 785 | | |
| Credit carried back to previous years (amount K6 in Part 27) | | s | |
| Subtotal (line 785 **plus** amount s) | | ▶ | J6 |
| **ITC closing balance from child care spaces expenditures** (amount I6 **minus** amount J6) | | 790 | |

## Part 27 – Request for carryback of credit from child care space expenditures

| | Year Month Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2017-12-31 | Credit to be applied | 941 | |
| 2nd previous tax year | 2016-12-31 | Credit to be applied | 942 | |
| 3rd previous tax year | 2015-12-31 | Credit to be applied | 943 | |

Total of lines 941 to 943
Enter at amount s in Part 26. K6

## Recapture – Child Care Spaces

### Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

| | | | | |
|---|---|---|---|---|
| If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) | | 792 | | |
| In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of: | | | | |
| The amount that can reasonably be considered to have been included in the original ITC | 795 | | | |
| 25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property | 797 | | | |
| Amount from line 795 or line 797, whichever is less | | | | A7 |

**Partnerships**

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

| | | | |
|---|---|---|---|
| **Corporate partner's share of the excess of ITC** | 799 | | |
| **Total recapture of child care spaces investment tax credit** (total of line 792, amount A7, and line 799)<br>Enter at amount B8 in Part 29. | | | B7 |

## Summary of Investment Tax Credits

### Part 29 – Total recapture of investment tax credit

| | | |
|---|---|---|
| Recaptured SR&ED ITC (amount F3 in Part 17) | | A8 |
| Recaptured child care spaces ITC (amount B7 in Part 28) | | B8 |
| **Total recapture of investment tax credit** (amount A8 **plus** amount B8)<br>Enter on line 602 of the T2 return. | | C8 |

### Part 30 – Total ITC deducted from Part I tax

| | | |
|---|---|---|
| ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5) | | D8 |
| ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12) | 75,985 | E8 |
| ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 19) | | F8 |
| ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 22) | 16,000 | G8 |
| ITC from child care space expenditures deducted from Part I tax (line 785 in Part 26) | | H8 |
| **Total ITC deducted from Part I tax** (total of amounts D8 to H8)<br>Enter on line 652 of the T2 return. | 91,985 | I8 |

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|
| 16,000 | 16,000 | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2017-12-31 | | | | |
| 2016-12-31 | | | | |
| 2015-12-31 | | | | |
| 2014-12-31 | | | | |
| 2013-12-31 | | | | |
| 2012-12-31 | | | | |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | * |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2001-09-30 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | * |
| **Total** | | | | |

B+C+D+G **Total ITC utilized** 16,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

**Current year**

| | Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|---|
| | 75,985 | 75,985 | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2017-12-31 | | | | |
| 2016-12-31 | | | | |
| 2015-12-31 | | | | |
| 2014-12-31 | | | | |
| 2013-12-31 | | | | |
| 2012-12-31 | | | | |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | * |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2001-09-30 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | * |
| **Total** | | | | |

B+C+D+G **Total ITC utilized** 75,985

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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**Schedule 33**

# Taxable Capital Employed in Canada – Large Corporations

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

## Part 1 – Capital

**Add** the following year-end amounts:

| | | | | |
|---|---|---|---|---|
| Reserves that have not been deducted in calculating income for the year under Part I | 101 | 63,262,321 | | |
| Capital stock (or members' contributions if incorporated without share capital) | 103 | 31,008,479 | | |
| Retained earnings | 104 | 98,676,433 | | |
| Contributed surplus | 105 | | | |
| Any other surpluses | 106 | 516,527 | | |
| Deferred unrealized foreign exchange gains | 107 | | | |
| All loans and advances to the corporation | 108 | 22,921,639 | | |
| All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations | 109 | | | |
| Any dividends declared but not paid by the corporation before the end of the year | 110 | | | |
| All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year | 111 | | | |
| The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below) | 112 | | | |
| Subtotal (**add** lines 101 to 112) | | 216,385,399 | 216,385,399 | A |

**Note:**

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

## Part 1 – Capital (continued)

| | | | |
|---|---|---|---|
| Subtotal A (from page 1) | | 216,385,399 | A |
| **Deduct** the following amounts: | | | |
| Deferred tax debit balance at the end of the year | 121 | | |
| Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year | 122 | | |
| To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year. | 123 | | |
| Deferred unrealized foreign exchange losses at the end of the year | 124 | | |
| Subtotal (**add** lines 121 to 124) | | ► | B |
| **Capital for the year** (amount A **minus** amount B) (if negative, enter "0") | 190 | 216,385,399 | |

## Part 2 – Investment allowance

**Add** the carrying value at the end of the year of the following assets of the corporation:

| | | |
|---|---|---|
| A share of another corporation | 401 | |
| A loan or advance to another corporation (other than a financial institution) | 402 | |
| A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution) | 403 | |
| Long-term debt of a financial institution | 404 | |
| A dividend payable on a share of the capital stock of another corporation | 405 | |
| A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1) | 406 | |
| An interest in a partnership (see note 2 below) | 407 | |
| **Investment allowance for the year** (add lines 401 to 407) | 490 | |

**Notes:**

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

## Part 3 – Taxable capital

| | | | |
|---|---|---|---|
| Capital for the year (line 190) | | 216,385,399 | C |
| **Deduct:** Investment allowance for the year (line 490) | | | D |
| **Taxable capital for the year** (amount C **minus** amount D) (if negative, enter "0") | 500 | 216,385,399 | |

## Part 4 – Taxable capital employed in Canada

**To be completed by a corporation that was resident in Canada at any time in the year**

Taxable capital for the year (line 500) 216,385,399 x Taxable income earned in Canada **610** 15,363,245 / Taxable income 15,363,245 = **Taxable capital employed in Canada** **690** 216,385,399

**Notes:**
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

**To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada**

| | | | |
|---|---|---|---|
| Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . | | **701** | |
| **Deduct** the following amounts: | | | |
| Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . . | **711** | | |
| Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . . | **712** | | |
| Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . . | **713** | | |
| Total deductions (**add** lines 711, 712, and 713) | | ► | E |
| **Taxable capital employed in Canada** (line 701 **minus** amount E) (if negative, enter “0“) . . . . . | | **790** | |

**Note:** Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

## Part 5 – Calculation for purposes of the small business deduction

**This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.**

| | | |
|---|---|---|
| Taxable capital employed in Canada (amount from line 690) . . . . . | | F |
| **Deduct:** . . . . . | 10,000,000 | G |
| Excess (amount F **minus** amount G) (if negative, enter "0") | | H |
| **Calculation for purposes of the small business deduction** (amount H x 0.225%) . . . . . | | I |

Enter this amount at line 415 of the T2 return.

# Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| Non-deductible reserves per schedule 13 | | 63,262,321 | 00 |
| | + | | |
| | **Total** | 63,262,321 | 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

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| Customer deposits - long term portion (deferred customer contributions) | | 14,447,081 | 00 |
| Customer deposits - current portion | + | 8,474,558 | 00 |
| | + | | |
| | + | | |
| | + | | |
| | **Total** | 22,921,639 | 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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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100 | Business Number (If a corporation is not registered, enter "NR") 200 | Social insurance number 300 | Trust number 350 | Percentage common shares 400 | Percentage preferred shares 500 |
|---|---|---|---|---|---|---|
| | | Provide only one number per shareholder | | | | |
| 1 | Windsor Canada Utilities Ltd. | 86712 9181 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

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**Schedule 53**

# General Rate Income Pool (GRIP) Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

On: 2018-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- Credit unions are **not** required to complete this schedule.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- When an eligible dividend was paid in the tax year or there was a change in the GRIP balance, file a completed copy of this schedule with your T2 *Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☐ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – General rate income pool (GRIP)

| | | | | | |
|---|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | 100 | 57,011,315 | A |
| Taxable income for the year (DICs enter "0") * | 110 | 15,363,245 B | | | |
| Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less * | 130 | | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * | 140 | 636,672 | | | |
| Subtotal (line 130 **plus** line 140) | | 636,672 ▶ | 636,672 C | | |
| Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0") | 150 | 14,726,573 | | | |
| After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year)) | | | 190 | 10,603,133 | D |
| Eligible dividends received in the tax year | 200 | 5,248 | | | |
| Dividends deductible under section 113 received in the tax year | 210 | | | | |
| Subtotal (line 200 **plus** line 210) | | 5,248 ▶ | | 5,248 | E |
| Becoming a CCPC (amount W5 in Part 4) | 220 | | | | |
| Post-amalgamation (total of amounts E4 in Part 3 and amounts W5 in Part 4) | 230 | | | | |
| Post-wind-up (total of amounts E4 in Part 3 and amounts W5 in Part 4) | 240 | | | | |
| Subtotal (**add** lines 220, 230, and 240) | 290 | ▶ | | | F |
| Subtotal (**add** amounts A, D, E, and F) | | | | 67,619,696 | G |
| Eligible dividends paid in the previous tax year | 300 | | | | |
| Excessive eligible dividend designations made in the previous tax year | 310 | | | | |
| (If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.) | | | | | |
| Subtotal (line 300 **minus** line 310) | | ▶ | | | H |
| GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative) | | | 490 | 67,619,696 | |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount N3 in Part 2) | | | 560 | | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55. | | | 590 | 67,619,696 | |

* For lines 110, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2017-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . 14,417,162 A1

**Enter the following amounts before specified future tax consequences from the current tax year:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ B1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 320,425 C1

Subtotal (amount B1 **plus** amount C1) 320,425 ► 320,425 D1

Subtotal (amount A1 **minus** amount D1) (if negative, enter "0") 14,096,737 ► 14,096,737 E1

| **Future tax consequences that occur for the current year**<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ F1

**Enter the following amounts after specified future tax consequences:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ G1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ H1

Subtotal (amount G1 **plus** amount H1) ______ ► ______ I1

Subtotal (amount F1 **minus** amount I1) (if negative, enter "0") ______ ► ______ J1

Subtotal (amount E1 **minus** amount J1) (if negative, enter "0") ______ K1

**GRIP adjustment for specified future tax consequences to the first previous tax year**
(amount K1 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Second previous tax year** 2016-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . 17,181,266 A2

**Enter the following amounts before specified future tax consequences from the current tax year:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ B2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 376,223 C2

Subtotal (amount B2 **plus** amount C2) 376,223 ▶ 376,223 D2

Subtotal (amount A2 **minus** amount D2) (if negative, enter "0") 16,805,043 ▶ 16,805,043 E2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ F2

**Enter the following amounts after specified future tax consequences:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ G2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ H2

Subtotal (amount G2 **plus** amount H2) ______ ▶ ______ I2

Subtotal (amount F2 **minus** amount I2) (if negative, enter "0") ______ ▶ ______ J2

Subtotal (amount E2 **minus** amount J2) (if negative, enter "0") ______ K2

**GRIP adjustment for specified future tax consequences to the second previous tax year**
(amount K2 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . **520** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2015-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . 10,855,629 A3

**Enter the following amounts before specified future tax consequences from the current tax year:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ B3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 111,525 C3

Subtotal (amount B3 **plus** amount C3) 111,525 ▶ 111,525 D3

Subtotal (amount A3 **minus** amount D3) (if negative, enter "0") 10,744,104 ▶ 10,744,104 E3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ F3

**Enter the following amounts after specified future tax consequences:**

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ______ G3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ H3

Subtotal (amount G3 **plus** amount H3) ______ ▶ ______ I3

Subtotal (amount F3 **minus** amount I3) (if negative, enter "0") ______ ▶ ______ J3

Subtotal (amount E3 **minus** amount J3) (if negative, enter "0") ______ K3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(amount K3 **multiplied by** 0.72 ) . . . . . . . . . . . . . . . . . . . . **540** ______

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . . . . . . . . . . . . ______ L3

Enter amount L3 on line 560 in part 1.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

| | | | |
|---|---|---|---|
| Corporation's GRIP at the end of its last tax year | | | A4 |
| Eligible dividends paid by the corporation in its last tax year | | B4 | |
| Excessive eligible dividend designations made by the corporation in its last tax year | | C4 | |
| Subtotal (amount B4 **minus** amount C4) | | ► | D4 |
| **GRIP addition post-amalgamation or post-wind-up** (predecessor or subsidiary was a CCPC or a DIC in its last tax year) (amount A4 **minus** amount D4) | | | E4 |

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year.The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ______ A5

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . ______ B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ C5

Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ D5

Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ E5

Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . ______ F5

Limited partnership losses . . . . . . . . . . . . . . . . . . . . ______ G5

Subtotal (**add** amounts C5 to G5) ______ ▶ ______ H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ I5

Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J5

Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ K5

Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . ______ L5

Limited partnership losses . . . . . . . . . . . . . . . . . . . . ______ M5

Subtotal (**add** amounts I5 to M5) ______ ▶ ______ N5

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5) ______ ▶ ______ O5

Subtotal (**add** amounts A5, B5, and O5) ______ P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ______ Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . ______ R5

All the corporation's reserves deducted in its previous/last tax year . . . . . . . . . . . . . . . . . . . ______ S5

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ T5

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ U5

Subtotal (**add** amounts Q5 to U5) ______ ▶ ______ V5

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (amount P5 **minus** amount V5) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . ______ W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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**Schedule 55**

# Part III.1 Tax on Excessive Eligible Dividend Designations

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

**Do not use this area**

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

## Part 1 – Canadian-controlled private corporations and deposit insurance corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | 3,000,000 | | | |
| Total taxable dividends paid in the tax year | 100 | 3,000,000 | | | |
| Total eligible dividends paid in the tax year | | | 150 | | A |
| GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0") | | | 160 | 67,619,696 | B |
| Excessive eligible dividend designation (line 150 **minus** line 160) | | | | | C |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends * | | | 180 | | D |
| Subtotal (amount C **minus** amount D) | | | | | E |
| **Part III.1 tax on excessive eligible dividend designations – CCPC or DIC** (amount E **multiplied** by 20 %) | | | 190 | | F |

Enter the amount from line 190 on line 710 of the T2 return.

## Part 2 – Other corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | | | | |
| Total taxable dividends paid in the tax year | 200 | | | | |
| Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54) | | | | | G |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends * | | | 280 | | H |
| Subtotal (amount G **minus** amount H) | | | | | I |
| **Part III.1 tax on excessive eligible dividend designations – Other corporations** (amount I **multiplied** by 20 %) | | | 290 | | J |

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.



Canada

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**Schedule 89**

# Request for Capital Dividend Account Balance Verification

**Protected B** when completed

| Corporation's name | Business number |
|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 |

- If you are a private corporation, use this schedule to summarize the components making up your capital dividend account (CDA) balance as of the CDA balance date shown in the field located above Part 1.
- Mail one completed copy of this schedule, separately from any other return, to the Prince Edward Island Tax Centre at 275 Pope Road, Summerside PE C1N 6A2.
- For specific details about calculating the CDA balance, see the applicable legislation in the federal Income Tax Act.
- All legislative references are to the current version of the Act. But since the CDA balance components can span several years, these references may not apply to older components of your CDA balance. In these cases, see the version of the Act that applies to the appropriate year.
- All references to paragraphs in subsection 89(1) of the Act are under the definition of "capital dividend account".
- If you are paying out a capital dividend from your CDA, you must file Form T2054, Election for a Capital Dividend under Subsection 83(2). Attach a copy of this completed form. Note that if a capital dividend paid out under this election exceeds the balance of the CDA at the time the dividend becomes payable, you may have to pay Part III tax on the excessive dividends (see section 184 of the Act).

Capital dividend account balance as of (Year Month Day) 2018-12-31

**Please check one of the following:**

Is this a balance verification request? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Yes [ ] No [ ]

Is this request related to the requirements of section 89(1) for Form T2054? . . . . . . . . . . . . . . . . . . . . . . . . . . . Yes [ ] No [X]

## Part 1 – CDA components (except for eligible capital property) (Note 1 and Note 2)

| | 1<br>Tax year-end or relevant date (YYYY/MM/DD) (Note 3) | 2<br>The non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and non-deductible portion of capital losses per paragraph 89(1)(a) (Note 4) | 3<br>Capital dividends received per paragraph 89(1)(b) (Note 5) | 4<br>Net proceeds of a life insurance policy per paragraph 89(1)(d) | 5<br>Non-taxable portion of capital gains from a trust before September 16, 2016 per paragraph 89(1)(f) (Note 6) | 6<br>Capital dividends from a trust per paragraph 89(1)(g) (Note 6) | 7<br>Capital dividends payable per subsection 83(2) |
|---|---|---|---|---|---|---|---|
| 1. | 2011-12-31 | 42,774 | | | | | |
| 2. | 2012-12-31 | | | | | | |
| 3. | 2013-12-31 | | | | | | |
| 4. | 2014-12-31 | -667 | | | | | |
| 5. | 2015-12-31 | 53,191 | | | | | |
| 6. | 2016-12-31 | 109,321 | | | | | |
| 7. | 2017-12-31 | 74,540 | | | | | |
| | 2018-12-31 | 26,660 | | | | | |
| | **Totals** | 305,819 | | | | | |

If you need more space, use additional sheets.

Note 1. For eligible capital property, see parts 2 and 4.

Note 2. If you were a private corporation under non-resident control that became Canadian controlled as per subsection 89(1.1), or were a tax-exempt corporation that became taxable as per subsection 89(1.2), the CDA balance may be reduced to nil immediately before the dates referred to in those provisions.

Note 3. Include as many tax years as required. Start your list with the tax year that began after the corporation became a private corporation and that ended after 1971. End your list on the CDA balance date shown in the field located above Part 1. If you are completing this schedule before your tax year-end, enter the relevant date of the activity. When Form T2054 has been completed, the program assumes that the relevant date of the activity to indicate in the last field of column 1 in Part 1 is the first of the following dates: the day immediately preceding the date on which the dividend becomes payable, or the first day immediately preceding the date on which any part of the dividend was paid. If this is not the case, enter the correct relevant date of the activity, using an override.

Note 4. Along with applicable losses, include the non-deductible portion of a business investment loss here. Show losses as a negative.

Note 5. May be adjusted by an excessive dividend election under subsection 184(3). Exclude a dividend that subsection 83(2.1) applies to.

Note 6. The amounts that can be added to the CDA of the corporation in a particular tax year, in respect of amounts received by the corporation, from a trust and that are attributable to capital gains realized by the trust or to dividends received and distributed by a trust, can only be determined after the end of the taxation year of the trust in which the capital gains were realized or the dividends were received and distributed by it.

## Part 2 – CDA components – Eligible capital property (ECP)

Record in these tables the most common amounts included in the eligible capital property (ECP) component of the CDA. This information is not meant to replace the calculation at line C in Part 4.

**Section A: CDA components – List of eligible capital property acquisitions and dispositions** (for tax years ending before **February 28, 2000)**

| | 1<br>Tax year-end (YYYY/MM/DD) | 2<br>Cost of eligible capital property acquired | 3<br>Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property | 4<br>Non-taxable portion of ECP sales |
|---|---|---|---|---|
| 1. | | | | |
| | | | **Total** | |

If you need more space, use additional sheets.

**Section B: CDA components – List of ECP dispositions (**for tax years ending after **February 27, 2000** and before **January 1, 2017 )**

| | 1<br>Tax year-end (YYYY/MM/DD) | 2<br>Amount S from Schedule 10 | 3<br>Appropriate portion of the amount deducted as a bad debt per subsection 20(4.2) or as an allowable capital loss per subsection 20(4.3) | 4<br>Non-taxable portion of ECP sales (column 2 **minus** column 3) |
|---|---|---|---|---|
| 1. | 2011-12-31 | | | |
| 2. | 2012-12-31 | | | |
| 3. | 2013-12-31 | | | |
| 4. | 2014-12-31 | | | |
| | | | **Total** | |

If you need more space, use additional sheets.

**Protected B**
when completed

## Part 3 – Additional information

For each capital dividend received, as recorded in column 3 in Part 1, give the name and business number of the corporation that paid the capital dividend and the date the dividend became payable.

| | 1<br>Corporation's name | 2<br>Business number | 3<br>Date the dividend became payable (YYYY/MM/DD) |
|---|---|---|---|
| 1. | | | |

If you need more space, use additional sheets.

## Part 4 – CDA balance

| | | |
|---|---|---|
| Include the non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and the non-deductible portion of capital losses (total of column 2 in Part 1; if negative enter "0") | 305,819 | A |
| Capital dividends received (total of column 3 in Part 1) | | B |
| Eligible capital property for taxation years ending before January 1, 2017 (as calculated per former paragraphs 89(1)(c), (c.1) and (c.2); if negative, enter "0") | | C |
| Life insurance proceeds (total of column 4 in Part 1; if negative, enter "0") | | D |
| Life insurance CDA (Note 7) | | E |
| Non-taxable portion of capital gains from a trust before September 16, 2016 (total of column 5 in Part 1) | | F |
| Capital dividends from a trust (total of column 6 in Part 1) | | G |
| Amounts from predecessor and subsidiary corporations (Note 8) | | H |
| Subtotal (total of amounts A to H) | 305,819 | I |
| Capital dividends that previously became payable (total of column 7 in Part 1) | | J |
| **CDA balance** (amount I **minus** amount J) | 305,819 | K |

Note 7. Include the balance of the corporation's life insurance CDA immediately before May 24, 1985, in accordance with paragraph 89(1)(e). For more information, see paragraph 1.61 and 1.62 of Income Tax Folio S3-F2-C1, Capital Dividends.

Note 8.
- For amalgamations and wind-ups **before** July 14, 1990, calculate the CDA balance of each predecessor or subsidiary corporation separately. Then add these CDA balances to the CDA of the successor or parent corporation. Do not carry forward negative amounts, since these are considered to be nil.
- For amalgamations and wind-ups **after** July 13, 1990, carry over the amounts of all the CDA components of each predecessor or subsidiary corporation into the calculation of the CDA components of the new corporation. As a result, a negative balance in a component of a CDA of a predecessor or subsidiary corporation has to show in the CDA of the successor or parent corporation. Include a separate CDA calculation on a separate schedule for each predecessor or subsidiary corporation.
- For amalgamations, see paragraph 87(2)(z.1). For wind-ups, see paragraph 88(1)(e.2).

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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule if the corporation had a permanent establishment, under section 400 of the federal Income Tax Regulations, in Ontario at any time in the tax year and had Ontario taxable income in the year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

## Part 1 – Ontario basic income tax

| | | |
|---|---|---|
| Ontario taxable income * | 15,363,245 | A |
| **Ontario basic rate of tax for the year** | 11.5 % | B |
| **Ontario basic income tax** (amount A **multiplied** by amount B **) | 1,766,773 | C |

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or amount Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

** If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

## Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1).

| | | | | |
|---|---|---|---|---|
| Amount from line 400 of the T2 return | 14,733,473 | 1 | | |
| Amount from line 405 of the T2 return | 15,362,931 | 2 | | |
| Amount from line 427 of the T2 return (note) | | 3 | | |
| Enter the least of amounts 1, 2 or 3 | | ▶ | | D |
| Ontario domestic factor (ODF): Taxable income for Ontario * / Taxable income for all provinces ** | 15,363,245.00 / 15,363,245 = | | 1.00000 | E |
| Amount D **multiplied** by amount E | | 4 | | |
| Ontario taxable income (amount A from Part 1) | 15,363,245 | 5 | | |
| Ontario small business income (lesser of amount 4 or amount 5) | | ▶ | | F |

**Ontario small business deduction rate for the year**

| | | | | | | |
|---|---|---|---|---|---|---|
| Number of days in the tax year before January 1, 2018 / Number of days in the tax year | / 365 | x | 7 % | = | % | G1 |
| Number of days in the tax year after December 31, 2017 / Number of days in the tax year | 365 / 365 | x | 8 % | = | 8.00000 % | G2 |

| | | | | |
|---|---|---|---|---|
| OSBD rate for the year (rate G1 **plus** rate G2) | 8.00000 % | ▶ | 8.00000 % | G |
| **Ontario small business deduction** (amount F **multiplied** by rate G) | | | | H |

Enter amount H on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

**Note:** On November 15, 2018, the Government of Ontario announced, in Bill 57, that the reduction in the business limit relating to the amount of passive investment income for taxation years starting after December 31, 2018, will not be applied when calculating the Ontario small business deduction. As a result, the calculation on line 3 does not take the amount on line G of Schedule 200 (Jump Code: **J**) into account.

## Part 3 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount 5) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . I

Enter amount I at amount K in Part 4 of this schedule or at amount B in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

## Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 2H from Schedule 17 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . J

Ontario adjusted small business income (amount I) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . K

Subtotal (amount J **minus** amount K, if negative, enter "0") L

Amount L **multiplied** by amount G . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . M

Ontario domestic factor (amount E) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1.00000 N

**Ontario credit union tax reduction** (amount M **multiplied** by amount N) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . O

Enter amount O on line 410 of Schedule 5.

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**Schedule 508**

# Ontario Research and Development Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - add an ORDTC transferred after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016;
  - 3.5% for tax years that start after May 31, 2016; and
  - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

## Part 1 – Ontario SR&ED expenditure pool

| | Line | Amount | | | |
|---|---|---|---|---|---|
| Total eligible expenditures incurred by the corporation in Ontario in the tax year | 100 | 532,937 | A | | |
| Government assistance, non-government assistance, or a contract payment for eligible expenditures | 105 | 8,000 | B | | |
| Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0") | | 524,937 | C | | |
| Eligible expenditures transferred to the corporation by another corporation | 110 | | D | | |
| Subtotal (amount C **plus** amount D) | | 524,937 | ▶ | 524,937 | E |
| Eligible expenditures the corporation transferred to another corporation | 115 | | | | F |
| **Ontario SR&ED expenditure pool** (amount E **minus** amount F) (if negative, enter "0") | 120 | | | 524,937 | G |

## Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 . . . . . . . . . **210** ______ x 4.5 % = **215** ______ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Number of days in the tax year before June 1, 2016 | 240 | 152 | x | 4.5 % | = | 1.8689 % | 1 |
| Number of days in the tax year | 241 | 366 | | | | | |
| Number of days in the tax year after May 31, 2016 | 242 | 214 | x | 3.5 % | = | 2.0464 % | 2 |
| Number of days in the tax year | 243 | 366 | | | | | |

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 . . . . . . **211** ______ x percentage 3 3.9153 % = **216** ______ I

## Part 2 – Eligible repayments (continued)

| | | | | | | |
|---|---|---|---|---|---|---|
| Repayments for tax years that start after May 31, 2016 | 212 | | x 3.5 % | = 217 | | J |
| Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014 | 220 | x 1 / 4 = | x 4.5 % | = 225 | | K |
| **Eligible repayments** (total of amounts H to K) | | | | 229 | | L |

## Part 3 – Calculation of the current part of the ORDTC

**For tax years that end before June 1, 2016**

| | | | | | |
|---|---|---|---|---|---|
| Ontario SR&ED expenditure pool (amount G in Part 1) | | x 4.5 % | = 200 | | M |
| ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * | | | 205 | | N |
| Eligible repayments (amount L in Part 2) | | | | | O |
| **Current part of the ORDTC for tax years that end before June 1, 2016** (total of amounts M to O) | | | 230 | | P |

**For a tax year that ends on or after June 1, 2016, and includes May 31, 2016**

$\frac{\text{Number of days in the tax year before June 1, 2016}}{\text{Number of days in the tax year}}$ ______ x 4.5 % = ______ % 4

$\frac{\text{Number of days in the tax year after May 31, 2016}}{\text{Number of days in the tax year}}$ ______ x 3.5 % = ______ % 5

Subtotal (percentage 4 **plus** percentage 5) ______ % 6

| | | | | | |
|---|---|---|---|---|---|
| Ontario SR&ED expenditure pool (amount G in Part 1) | | x percentage 6 ______ % | = 201 | | Q |
| ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * | | | 206 | | R |
| Eligible repayments (amount L in Part 2) | | | | | S |
| **Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016** (total of amounts Q to S) | | | 231 | | T |

**For tax years that start after May 31, 2016**

| | | | | | |
|---|---|---|---|---|---|
| Ontario SR&ED expenditure pool (amount G in Part 1) | 524,937 | x 3.5 % | = 202 | 18,373 | U |
| ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * | | | 207 | | V |
| Eligible repayments (amount L in Part 2) | | | | | W |
| **The ORDTC for tax years that start after May 31, 2016** (total of amounts U to W) | | | 232 | 18,373 | X |

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

## Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

| | | | | |
|---|---|---|---|---|
| ORDTC balance at the end of the previous tax year | | | | Y |
| ORDTC expired after 20 tax years | **300** | | | Z |
| ORDTC at the beginning of the tax year (amount Y **minus** amount Z) | **305** | | | AA |
| ORDTC transferred to the corporation on amalgamation or windup | **310** | | | BB |
| **Current part of ORDTC** (amount P, T or X in Part 3 whichever applies) | | 18,373 CC | | |

Are you waiving all or part of the current part of the ORDTC? **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

| | | | | | |
|---|---|---|---|---|---|
| Waiver of the current part of the ORDTC | **320** | DD | | | |
| Subtotal (amount CC **minus** amount DD) | | 18,373 ▶ | 18,373 | EE | |
| **ORDTC available for deduction** (total of amounts AA, BB and EE) | | | 18,373 ▶ | | 18,373 FF |
| ORDTC claimed ** (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*) | | | 18,373 | GG | |
| ORDTC carried back to previous tax years (from Part 5) | | | | HH | |
| Subtotal (amount GG **plus** amount HH) | | | 18,373 ▶ | | 18,373 II |
| **ORDTC balance at the end of the tax year** (amount FF **minus** amount II) | **325** | | | | JJ |

** This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

## Part 5 – Request for carryback of tax credit

| | Year Month Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2017-12-31 | Credit to be applied | **901** | |
| 2nd previous tax year | 2016-12-31 | Credit to be applied | **902** | |
| 3rd previous tax year | 2015-12-31 | Credit to be applied | **903** | |

**Total** (total of amount 901 to 903)(enter at amount HH in Part 4)

## Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from previous tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

| Tax year of origin (earliest tax year first) Year-Month-Day | Credit available |
|---|---|
| 1999-12-31 | |
| 2000-12-31 | |
| 2001-09-30 | |
| 2001-12-31 | |
| 2002-12-31 | |
| 2003-12-31 | |
| 2004-12-31 | |
| 2005-12-31 | |
| 2006-12-31 | |
| 2007-12-31 | |
| 2008-12-31 | |
| 2009-12-31 | |
| 2010-12-31 | |
| 2011-12-31 | |
| 2012-12-31 | |
| 2013-12-31 | |
| 2014-12-31 | |
| 2015-12-31 | |
| 2016-12-31 | |
| 2017-12-31 | |
| Current tax year 2018-12-31 | |

**Total** (equals line 325 in Part 4) ____________

The amount available from the 20th previous tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

## Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  **Note:** The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate ******* of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

*** Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

**Calculation 1** – Complete this part If you meet all of the above conditions

| | KK<br>Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above<br>700 | LL<br>Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case)<br>710 | MM<br>Amount from column 700 or 710, whichever is less |
|---|---|---|---|
| 1. | | | |

Total of column MM (enter at amount WW in Part 8 ) ____________ NN

## Part 7 – Calculation of a recapture of ORDTC (continued)

**Calculation 2** – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

| | OO<br>Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act<br>720 | PP<br>Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition<br>730 | QQ<br>Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act)<br>740 |
|---|---|---|---|
| 1. | | | |

| | RR<br>Amount determined by the formula (OO x PP) - QQ (using the columns above) | SS<br>Federal ITC earned by the transferee for the qualified expenditure that was transferred<br>750 | TT<br>Amount from column RR or SS, whichever is less |
|---|---|---|---|
| 1. | | | |

Total of column TT (enter at amount XX in Part 8) ______ UU

**Calculation 3**

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) . . . . . . . . . . . . . . . . . . . . . . . . . . **760** ______ VV

## Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7) . . . . . . . . . . . ______ WW

Recaptured federal ITC for Calculation 2 (amount UU from Part 7) . . . . . . . . . . . ______ XX

Amount WW **plus** amount XX . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ x 23.56 % = ______ YY

Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7) . . . . . . . . . . . . . . . . . . . . . . ______ ZZ

**Recapture of ORDTC** (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . . . . . . . . . . ______ AAA

# Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

**Enter the breakdown between current and capital expenditures**

| | | Current Expenditures | | | Capital Expenditures | |
|---|---|---|---|---|---|---|
| **Total expenditures for SR&ED** | | 452,962 | | | | |
| **Add** | | | | | | |
| • payment of prior years' unpaid expenses (other than salary or wages) | + | | | | | |
| • prescribed proxy amount (Enter "0" if you use the traditional method) | + | 124,208 | | | | |
| • expenditures on shared-use equipment | | | | + | | |
| • other additions | + | | | + | | |
| **Subtotal** | = | 577,170 | | = | | |
| **Less** | | | | | | |
| • current expenditures (other than salary or wages) not paid within 180 days of the tax year end | – | | | | | |
| • amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier | – | | | | | |
| • 20% of contract expenditures for SR&ED performed on your behalf | – | 44,233 | | | | |
| • prescribed expenditures not allowed by regulations | – | | | – | | |
| • other deductions | – | | | – | | |
| • non-arm's length transactions | | | | | | |
| – expenditures for non-arm's length SR&ED contracts | – | | | | | |
| – purchases (limited to costs) of goods and services from non-arm's length suppliers | – | | | – | | |
| **Subtotal** | = | 532,937 | I | = | | II |
| Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II) | | | | = | 532,937 | III |

Enter amount III on line 100 of Schedule 508.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 333,742,416 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 7,601,446 |
| Total assets (total of lines 112 to 116) | | 341,343,862 |
| Total revenue of the corporation for the tax year ** | 142 | 327,113,733 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 1,751,150 |
| Total revenue (total of lines 142 to 146) | | 328,864,883 |

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 13,508,482 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | 1,288,306 | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | 1,568,058 | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | 2,856,364 ▶ | | 2,856,364 A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | 5,257 | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 | 382 | | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | 5,257 ▶ | | 5,257 B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 16,359,589 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | | 515 | 16,359,589 | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | | | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | | |
| Adjusted CMT loss available | | ▶ | | C |
| Net income subject to CMT calculation (if negative, enter "0") | | 520 | 16,359,589 | |

Amount from line 520: 16,359,589 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 365) x 4 % = ______ 1

Amount from line 520: 16,359,589 x (Number of days in the tax year after June 30, 2010: 365 / Number of days in the tax year: 365) x 2.7 % = 441,709 2

Subtotal (amount 1 **plus** amount 2) . . . 441,709 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | 441,709 | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | 441,709 | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 1,748,400 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

**Ontario allocation factor** . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

## Part 4 – Calculation of CMT credit carryforward

| | | | | |
|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | | G |
| **Deduct:** | | | | |
| CMT credit expired * | 600 | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | 620 | |
| **Add:** | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | H |
| **Deduct:** | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | I |
| Subtotal (amount H **minus** amount I) | | | | J |
| **Add:** | | | | |
| Net CMT payable (amount E from Part 3) | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | |
| Subtotal | | | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

| | | | | |
|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 1,748,400 1 | | |
| For a corporation that is not a life insurance corporation: | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 441,709 2 | | | |
| For a life insurance corporation: | | | | |
| Gross CMT (line 540 from Part 3) | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | 4 | | | |
| The **greater** of amounts 3 and 4 | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | 441,709 6 | | |
| Subtotal (if negative, enter "0") | | 1,306,691 | 1,306,691 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 1,748,400 | | |
| **Deduct:** | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | 96,826 | | |
| Subtotal (if negative, enter "0") | | 1,651,574 | 1,651,574 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . ► 720

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . 750

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . .

Subtotal (if negative, enter "0") S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | Enwin Energy Ltd. | 88246 2526 RC0001 | 7,601,446 | 1,751,150 |
| 2 | Windsor Canada Utilities Ltd. | 86712 9181 RC0001 | 0 | 0 |
| 3 | Corporation of the City of Windsor | NR | 0 | 0 |
| 4 | Enwin Financial Services Ltd. | 83435 7147 RC0001 | 0 | 0 |
| | | **Total** | 450 7,601,446 | 550 1,751,150 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 546**

## *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

### Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Enwin Utilities Ltd.

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | **110** Date of incorporation or amalgamation, whichever is the most recent — Year Month Day | **120** Ontario Corporation No. |
|---|---|---|
| Ontario | 2007-01-01 | 001710758 |

### Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable): Byron Thompson

| **210** Street number | **220** Street name/Rural route/Lot and Concession number | **230** Suite number |
|---|---|---|
| 787 | Ouellette Avenue | |

**240** Additional address information if applicable (line 220 must be completed first)

| **250** Municipality (e.g., city, town) | **260** Province/state | **270** Country | **280** Postal/zip code |
|---|---|---|---|
| Windsor | ON | CA | N9A 4J4 |

### Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** 1 — If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

### Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** Reidel (Last name) **451** Helga (First name)

**454** ______________________, (Middle name(s))

**460** 2 — Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

**500** ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

**510** Care of (if applicable)

| **520** Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number |
|---|---|---|
| | | |

**550** Additional address information if applicable (line 530 must be completed first)

| **560** Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code |
|---|---|---|---|
| | | | |

## Part 6 – Language of preference

**600** ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| Helga Reidel | (519) 255-2869 |

Is the claim filed for a CETC earned through a partnership?* . . . . . . . . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 27,688,161

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | **A**<br>Name of university, college, or other eligible educational institution<br>**400** | **B**<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 2. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 3. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 4. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 5. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 6. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 7. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 8. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 9. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 10. | University of Windsor | BAS - ELECTRICAL ENGINEERING |
| 11. | University of Windsor | BSC - COMPUTER SCIENCE |
| 12. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 13. | University of Windsor | BCOMM - BUSINESS ADMIN |
| 14. | | |

| | **C**<br>Name of student<br>**410** | **D**<br>Start date of WP (see note 1 below)<br>**430** | **E**<br>End date of WP (see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2018-01-01 | 2018-04-30 |
| 2. | [redacted] | 2018-01-01 | 2018-04-30 |

| | C<br>Name of student<br>410 | D<br>Start date of WP<br>(see note 1 below)<br>430 | E<br>End date of WP<br>(see note 2 below)<br>435 |
|---|---|---|---|
| 3. | [redacted] | 2018-09-01 | 2018-12-31 |
| 4. | [redacted] | 2018-09-01 | 2018-12-31 |
| 5. | [redacted] | 2018-01-01 | 2018-04-30 |
| 6. | [redacted] | 2018-01-01 | 2018-04-30 |
| 7. | [redacted] | 2018-01-01 | 2018-04-30 |
| 8. | [redacted] | 2018-09-01 | 2018-12-31 |
| 9. | [redacted] | 2018-05-01 | 2018-08-31 |
| 10. | [redacted] | 2018-05-01 | 2018-08-31 |
| 11. | [redacted] | 2018-05-01 | 2018-08-31 |
| 12. | [redacted] | 2018-05-01 | 2018-08-31 |
| 13. | [redacted] | 2018-05-01 | 2018-08-31 |
| 14. | | | |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009 (see note 1 below)<br>450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009 (see note 1 below)<br>452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 13,506 | 25.000 % | | 17 |
| 2. | | 10.000 % | 12,598 | 25.000 % | | 17 |
| 3. | | 10.000 % | 12,163 | 25.000 % | | 17 |
| 4. | | 10.000 % | 12,181 | 25.000 % | | 17 |
| 5. | | 10.000 % | 12,163 | 25.000 % | | 17 |
| 6. | | 10.000 % | 13,068 | 25.000 % | | 17 |
| 7. | | 10.000 % | 12,954 | 25.000 % | | 17 |
| 8. | | 10.000 % | 11,005 | 25.000 % | | 17 |
| 9. | | 10.000 % | 13,485 | 25.000 % | | 17 |
| 10. | | 10.000 % | 14,474 | 25.000 % | | 17 |
| 11. | | 10.000 % | 16,924 | 25.000 % | | 17 |
| 12. | | 10.000 % | 11,641 | 25.000 % | | 17 |
| 13. | | 10.000 % | 13,068 | 25.000 % | | 17 |
| 14. | | 10.000 % | | 25.000 % | | |

| | G<br>Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below)<br>460 | H<br>Maximum CETC per WP (see note 3 below)<br>462 | I<br>CETC on eligible expenditures (column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance (see note 4 below)<br>480 | K<br>CETC for each WP (column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 3,377 | 3,000 | 3,000 | | 3,000 |
| 2. | 3,150 | 3,000 | 3,000 | | 3,000 |
| 3. | 3,041 | 3,000 | 3,000 | | 3,000 |
| 4. | 3,045 | 3,000 | 3,000 | | 3,000 |
| 5. | 3,041 | 3,000 | 3,000 | | 3,000 |
| 6. | 3,267 | 3,000 | 3,000 | | 3,000 |
| 7. | 3,239 | 3,000 | 3,000 | | 3,000 |
| 8. | 2,751 | 3,000 | 2,751 | | 2,751 |
| 9. | 3,371 | 3,000 | 3,000 | | 3,000 |
| 10. | 3,619 | 3,000 | 3,000 | | 3,000 |
| 11. | 4,231 | 3,000 | 3,000 | | 3,000 |
| 12. | 2,910 | 3,000 | 2,910 | | 2,910 |
| 13. | 3,267 | 3,000 | 3,000 | | 3,000 |
| 14. | | | | | |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 38,661 L or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . . . . . . . . ________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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**Schedule 552**

# Ontario Apprenticeship Training Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

**110** Name of person to contact for more information: Helga Reidel

**120** Telephone number: (519) 255-2869

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . . **300** 27,688,161

**For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:**

– If line 300 is $400,000 or less, enter 45% on line 312.
– If line 300 is $600,000 or more, enter 35% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \left( \frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . . **312** 35.000 %

**For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:**

– If line 300 is $400,000 or less, enter 30% on line 314.
– If line 300 is $600,000 or more, enter 25% on line 314.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A Trade code 400 | B Apprenticeship program/trade name 405 | C Name of apprentice 410 |
|---|---|---|---|
| 1. | 434a | Powerline Technician | [redacted] |
| 2. | 434a | Powerline Technician | [redacted] |
| 3. | 434a | Powerline Technician | [redacted] |
| 4. | 434a | Powerline Technician | [redacted] |
| 5. | 434a | Powerline Technician | [redacted] |
| 6. | 434a | Powerline Technician | [redacted] |
| 7. | 434a | Powerline Technician | [redacted] |
| 8. | 434a | Powerline Technician | [redacted] |
| 9. | 434a | Powerline Technician | [redacted] |
| 10. | 434a | Powerline Technician | [redacted] |
| 11. | | | |

| | D Original contract or training agreement number 420 | E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425 | F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430 | G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435 |
|---|---|---|---|---|
| 1. | CD2832 | 2014-11-05 | 2018-01-01 | 2018-06-07 |
| 2. | CD2836 | 2014-11-05 | 2018-01-01 | 2018-07-23 |
| 3. | CD2834 | 2014-11-05 | 2018-01-01 | 2018-07-27 |
| 4. | CD2835 | 2014-11-05 | 2018-01-01 | 2018-08-13 |
| 5. | CA4154 | 2016-06-01 | 2018-01-01 | 2018-11-02 |
| 6. | CA4153 | 2016-06-01 | 2018-01-01 | 2018-11-02 |
| 7. | CA4152 | 2016-06-02 | 2018-01-01 | 2018-12-31 |
| 8. | SYS035456 | 2017-05-23 | 2018-01-01 | 2018-12-31 |
| 9. | SYS035454 | 2017-05-23 | 2018-01-01 | 2018-12-31 |
| 10. | SYS036386 | 2017-06-12 | 2018-01-01 | 2018-12-31 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1)<br>425 | F<br>Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2)<br>430 | G<br>End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3)<br>435 |
|---|---|---|---|---|
| 11. | | | | |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015<br>(see note 1)<br>442 | H2<br>Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015<br>(see note 1)<br>443 | I<br>Maximum credit amount for the tax year<br>(see note 2)<br>445 |
|---|---|---|---|
| 1. | 158 | | 4,329 |
| 2. | 204 | | 5,589 |
| 3. | 208 | | 5,699 |
| 4. | 225 | | 6,164 |
| 5. | | 306 | 4,192 |
| 6. | | 306 | 4,192 |
| 7. | | 365 | 5,000 |
| 8. | | 365 | 5,000 |
| 9. | | 365 | 5,000 |
| 10. | | 365 | 5,000 |
| 11. | | | |

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

| | J1<br>Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015<br>(see note 3)<br>452 | J2<br>Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015<br>(see note 3)<br>453 | K<br>Eligible expenditures **multiplied** by specified percentage<br>(see note 4)<br>460 |
|---|---|---|---|
| 1. | 65,869 | | 23,054 |
| 2. | 63,858 | | 22,350 |
| 3. | 59,776 | | 20,922 |
| 4. | 63,677 | | 22,287 |
| 5. | | 73,637 | 18,409 |
| 6. | | 71,071 | 17,768 |
| 7. | | 80,320 | 20,080 |
| 8. | | 64,875 | 16,219 |
| 9. | | 66,740 | 16,685 |
| 10. | | 75,448 | 18,862 |
| 11. | | | |

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.

For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

| | L<br>ATTC on eligible expenditures<br>(lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance<br>(see note 5)<br>480 | N<br>ATTC for each apprentice<br>(column L or M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 4,329 | | 4,329 |
| 2. | 5,589 | | 5,589 |
| 3. | 5,699 | | 5,699 |
| 4. | 6,164 | | 6,164 |

| | L<br>ATTC on eligible expenditures<br>(lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance<br>(see note 5)<br>480 | N<br>ATTC for each apprentice<br>(column L or M, whichever applies)<br>490 |
|---|---|---|---|
| 5. | 4,192 | | 4,192 |
| 6. | 4,192 | | 4,192 |
| 7. | 5,000 | | 5,000 |
| 8. | 5,000 | | 5,000 |
| 9. | 5,000 | | 5,000 |
| 10. | 5,000 | | 5,000 |
| 11. | | | |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 50,165 O

**Or**, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . ________ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

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**SCHEDULE 568**

# ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information*.
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return*.
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

## Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . . . . . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

## Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . . . . . . . . . . . . . . . . . . . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x days in the tax year 365 / 365 = . . . . . . . . . . . . . . . . . ________ B

**Qualified expenditure limit for the tax year** (amount A or amount B, whichever applies) . . . . . . . . . . . . . . . . . . . . . **210** 20,000,000 C

## Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

| | Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) 300 | Business Number (enter "NR" if corporation is not registered) 305 | Expenditure limit allocated 310 |
|---|---|---|---|
| 1. | Enwin Utilities Ltd. | 86712 0586 RC0002 | 20,000,000 |
| 2. | Enwin Energy Ltd. | 88246 2526 RC0001 | |
| 3. | Windsor Canada Utilities Ltd. | 86712 9181 RC0001 | |
| 4. | Corporation of the City of Windsor | NR | |
| 5. | Enwin Financial Services Ltd. | 83435 7147 RC0001 | |
| | **Total expenditure limit** (cannot exceed $20 million) | 315 | 20,000,000 D |

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

## Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year . . . . . 400 1

Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**) . . . . . 405 40,000 E

Qualified expenditure limit for the tax year (amount C in Part 2) . . . . . 20,000,000 F

Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less) . . . . . 410 40,000

**Ontario business-research Institute tax credit** (line 410 x 20 %) . . . . . 8,000 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

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**SCHEDULE 569**

# ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Enwin Utilities Ltd. | 86712 0586 RC0002 | 2018-12-31 |

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

## Part 1 – Contract details

**100** Name of person to contact for more information: Heather Malcolm-Kiss

**105** Telephone number including area code: (519) 255-2888

**110** Name of the ERI on the contract: University of Windsor

**115** ERI code: 119

**120** Date of contract (Year Month Day): 2018-02-21

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes ☐ 2 No ☐

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . . . . **130** ____ – ____

Is the claim filed for an OBRITC earned through a partnership?* . . . . . . **135** 1 Yes ☐ 2 No X

If the answer on line 135 is **yes**, are you a specified member? . . . . . . **140** 1 Yes ☐ 2 No ☐

If the answer on line 135 is **yes**, what is the name of the partnership? . . . . . . **145** ____

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . . . . **150** ____ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

## Part 2 – Eligibility

**Contract:**

1. Did the corporation enter into a contract with an ERI? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation? . . . . . **205** 1 Yes [X] 2 No [ ]
3. Was the corporation entitled to exploit the results of the SR&ED carried out under the contract? . . . . . **210** 1 Yes [X] 2 No [ ]

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

**Expenditures:**

4. Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment? . . . . . **215** 1 Yes [X] 2 No [ ]
5. Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI? . . . . . **220** 1 Yes [X] 2 No [ ]
6. Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages? . . . . . **225** 1 Yes [X] 2 No [ ]
7. Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation? . . . . . **230** 1 Yes [X] 2 No [ ]

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

## Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year . . . . . **300** 40,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 40,000 x percentage on line 150 in Part 1 ______ % = ______ A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . **305** 365

**Qualified expenditures for this contract for the tax year:**

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{14,600,000}{365} =$$

. . . . . **310** 40,000 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

# Corporate Taxpayer Summary

## Corporate information

Corporation's name . . . . . . . . . . . . Enwin Utilities Ltd.

Taxation Year . . . . . . . . . . . . . . . 2018-01-01 to 2018-12-31

Jurisdiction . . . . . . . . . . . . . . . . . Ontario

| BC | AB | SK | MB | ON | QC | NB | NS | NO | PE | NL | XO | YT | NT | NU | OC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | X | | | | | | | | | | | |

Corporation is associated . . . . . . . . Y

Corporation is related . . . . . . . . . . . Y

Number of associated corporations . . . 4

Type of corporation . . . . . . . . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . . . . . . . . . . . . -344,323

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

## Summary of federal information

| | | |
|---|---|---|
| Net income | | 15,375,402 |
| Taxable income | | 15,363,245 |
| Donations | | 6,900 |
| Calculation of income from an active business carried on in Canada | | 14,733,473 |
| Dividends paid | | 3,000,000 |
| Dividends paid – Regular | 3,000,000 | |
| Dividends paid – Eligible | | |
| Balance of the low rate income pool at the end of the previous year | | |
| Balance of the low rate income pool at the end of the year | | |
| Balance of the general rate income pool at the end of the previous year | | 57,011,315 |
| Balance of the general rate income pool at the end of the year | | 67,619,696 |
| Part I tax (base amount) | | 5,838,033 |

| Credits against part I tax | | Summary of tax | | Refunds/credits | |
|---|---|---|---|---|---|
| Small business deduction | | Part I | 2,363,093 | ITC refund | |
| M&P deduction | | Part IV | 2,015 | Dividends refund: | |
| Foreign tax credit | 88 | Part III.1 | | – Eligible dividends | |
| Investment tax credits | 91,985 | Other* | | – Non-eligible dividends | |
| Abatement/Other* | 3,450,779 | Provincial or territorial tax | 1,651,574 | Instalments | 4,163,764 |
| | | | | Other* | |
| | | | | **Balance due/refund (–)** | -344,323 |

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

## Summary of federal carryforward/carryback information

**Carryforward balances**

| | |
|---|---|
| Capital dividend amount | 305,819 |
| Financial statement reserve | 64,247,387 |
| Other reserves | 985,066 |

## Summary of provincial information – provincial income tax payable

| | Ontario | Québec (CO-17) | Alberta (AT1) |
|---|---|---|---|
| Net income | 15,375,402 | | |
| Taxable income | 15,363,245 | | |
| % Allocation | 100.00 | | |
| Attributed taxable income | 15,363,245 | | |
| Tax payable before deduction* | 1,766,773 | | |
| Deductions and credits | 18,373 | | |
| Net tax payable | 1,748,400 | | |
| Attributed taxable capital | N/A | | N/A |
| Capital tax payable** | N/A | | N/A |
| Total tax payable*** | 1,748,400 | | |
| Instalments and refundable credits | 96,826 | | |
| Balance due/Refund (-) | 1,651,574 | | |
| **Logging tax payable (COZ-1179)** | | | |
| Tax payable | N/A | | N/A |

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

## Summary – taxable capital

**Federal**

| Corporate name | Taxable capital used to calculate the business limit reduction (T2, line 415) | Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49) | Taxable capital used to calculate line 233 of the T2 return | Taxable capital used to calculate line 234 of the T2 return |
|---|---|---|---|---|
| Enwin Utilities Ltd. | 238,177,539 | 238,177,539 | 216,385,399 | 216,385,399 |
| Enwin Energy Ltd. | 6,819,422 | 6,819,422 | 6,776,839 | 6,776,839 |
| Windsor Canada Utilities Ltd. | 73,905,354 | 73,905,354 | 73,905,354 | 73,905,354 |
| Corporation of the City of Windsor | | | | |
| Enwin Financial Services Ltd. | 100 | 100 | 100 | 100 |
| Total | 318,902,415 | 318,902,415 | 297,067,692 | 297,067,692 |

**Québec**

| Corporate name | Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR) | Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) | Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E) | Paid-up capital used to determine the applicability of Form CO-737.SI |
|---|---|---|---|---|
| | | | | |
| Total | | | | |

**Ontario**

| Corporate name | Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566) |
|---|---|
| Enwin Utilities Ltd. | 230,141,553 |
| Enwin Energy Ltd. | |
| Windsor Canada Utilities Ltd. | |
| Corporation of the City of Windsor | |
| Enwin Financial Services Ltd. | |
| Total | 230,141,553 |

**Other provinces**

| Corporate name | Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306) |
|---|---|
| | |
| Total | |

# Five-Year Comparative Summary

## Federal information (T2)

| | Current year | 1st prior year | 2nd prior year | 3rd prior year | 4th prior year |
|---|---|---|---|---|---|
| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
| Net income | 15,375,402 | 14,468,638 | 17,197,900 | 10,882,417 | 12,875,362 |
| Taxable income | 15,363,245 | 14,417,162 | 17,181,266 | 10,855,629 | 12,779,088 |
| Active business income | 14,733,473 | 14,134,052 | 16,811,768 | 10,765,990 | 12,874,131 |
| Dividends paid | 3,000,000 | 4,000,000 | 4,000,000 | 3,000,000 | 4,750,000 |
| Dividends paid – Regular | 3,000,000 | 4,000,000 | 4,000,000 | 3,000,000 | 4,750,000 |
| Dividends paid – Eligible | | | | | |
| LRIP – end of the previous year | | | | | |
| LRIP – end of the year | | | | | |
| GRIP – end of the previous year | 57,011,315 | 46,847,509 | 34,737,974 | 26,997,986 | 17,797,035 |
| GRIP – end of the year | 67,619,696 | 57,011,315 | 46,847,509 | 34,737,974 | 26,997,986 |
| Donations | 6,900 | 37,315 | 6,725 | 21,886 | 95,754 |
| Balance due/refund (-) | -344,323 | -826,484 | -175,283 | -688,387 | -1,094,700 |
| **Line 996 – Amended tax return** | ☐ | ☐ | ☐ | ☐ | ☐ |

**Loss carrybacks requested in prior years to reduce taxable income**

| | | | | | |
|---|---|---|---|---|---|
| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
| Taxable income before loss carrybacks | N/A | N/A | 17,181,266 | 10,855,629 | 12,779,088 |
| Non-capital losses | N/A | N/A | | | |
| Net capital losses (50%) | N/A | N/A | | | |
| Restricted farm losses | N/A | N/A | | | |
| Farm losses | N/A | N/A | | | |
| Listed personal property losses (50%) | N/A | N/A | | | |
| Total loss carried back to prior years | N/A | N/A | | | |
| Adjusted taxable income after loss carrybacks | N/A | N/A | 17,181,266 | 10,855,629 | 12,779,088 |

**Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)**

| | | | | | |
|---|---|---|---|---|---|
| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
| Adjusted taxable income before current year loss carrybacks* | N/A | 14,417,162 | 17,181,266 | 10,855,629 | N/A |
| Non-capital losses | N/A | | | | N/A |
| Net capital losses (50%) | N/A | | | | N/A |
| Restricted farm losses | N/A | | | | N/A |
| Farm losses | N/A | | | | N/A |
| Listed personal property losses (50%) | N/A | | | | N/A |
| Total current year losses carried back to prior years | N/A | | | | N/A |
| Adjusted taxable income after loss carrybacks | N/A | 14,417,162 | 17,181,266 | 10,855,629 | N/A |

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

**Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax**

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks | N/A | N/A | 9,908 | 4,236 | 519 |
| Non-capital losses | N/A | N/A | | | |
| Farm losses | N/A | N/A | | | |
| Total loss carried back to prior years | N/A | N/A | | | |
| Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks | N/A | N/A | 9,908 | 4,236 | 519 |

**Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)**

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks*** | N/A | 14,160 | 9,908 | 4,236 | N/A |
| Non-capital losses | N/A | | | | N/A |
| Farm losses | N/A | | | | N/A |
| Total current year losses carried back to prior years | N/A | | | | N/A |
| Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks | N/A | 14,160 | 9,908 | 4,236 | N/A |

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

## Federal taxes

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| Part I | 2,363,093 | 2,155,258 | 2,572,128 | 1,482,867 | 1,821,113 |
| Part IV | 2,015 | 5,428 | 3,798 | 1,412 | 173 |
| Part III.1 | | | | | |
| Other* | | | | | |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

## Credits against part I tax

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| Small business deduction | | | | | |
| M&P deduction | | | | | |
| Foreign tax credit | 88 | 2,846 | 2,179 | 768 | 95 |
| Investment tax credit | 91,985 | 80,305 | 91,921 | 166,642 | 95,794 |
| Abatement/other* | 3,450,779 | 3,274,292 | 3,902,783 | 2,482,297 | 2,939,098 |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

## Refunds/credits

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| ITC refund | | | | | |
| Dividend refund | | | | | |
| – Eligible dividends | | | | | |
| – Non-eligible dividends | | 102,450 | 118,208 | 30,903 | 334 |
| Instalments | 4,163,764 | 4,393,226 | 4,454,099 | 3,221,000 | 4,291,248 |
| Other* | | | | | |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

## Ontario

| Taxation year end | 2018-12-31 | 2017-12-31 | 2016-12-31 | 2015-12-31 | 2014-12-31 |
|---|---|---|---|---|---|
| Net income | 15,375,402 | 14,468,638 | 17,197,900 | 10,882,417 | 12,875,362 |
| Taxable income | 15,363,245 | 14,417,162 | 17,181,266 | 10,855,629 | 12,779,088 |
| % Allocation | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |
| Attributed taxable income | 15,363,245 | 14,417,162 | 17,181,266 | 10,855,629 | 12,779,088 |
| Surtax | | | | | |
| Income tax payable before deduction | 1,766,773 | 1,657,974 | 1,975,846 | 1,248,397 | 1,469,595 |
| Income tax deductions /credits | 18,373 | 16,516 | 20,624 | 46,694 | 27,500 |
| Net income tax payable | 1,748,400 | 1,641,458 | 1,955,222 | 1,201,703 | 1,442,095 |
| Taxable capital | | | | | |
| Capital tax payable | | | | | |
| Total tax payable* | 1,748,400 | 1,641,458 | 1,955,222 | 1,201,703 | 1,442,095 |
| Instalments and refundable credits | 96,826 | 132,952 | 134,124 | 122,466 | 66,499 |
| Balance due/refund** | 1,651,574 | 1,508,506 | 1,821,098 | 1,079,237 | 1,375,596 |

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

# Attached Notes – Summary

☐ Name of the cell FDCFF.unusedTtwcff32 Form

Smart Meter Additions not Capitalized per book $3,341,356
Smart Meter Loss on Disposal Deferred per book $977,947

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Keep this note when rolling forward the file ☒

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☐ Name of the cell Tax return – Proceeds in excess of original cost – capital gain Form Sch. 8 - Fixed assets reconciliation

SS6.5

jsassine - 2019-02-22

Keep this note when rolling forward the file ☐

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☐ Name of the cell Corporation's salaries and wages paid in the previous tax year Form ON Sch. 550 - Co-operative education tax credit

G1 - Grouping 61500 and 61600

jsassine - 2019-02-26

Keep this note when rolling forward the file ☐

---

☐ Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

SS9

jsassine - 2019-02-26

Keep this note when rolling forward the file ☐

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☐ Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

SS9

jsassine - 2019-02-26

Keep this note when rolling forward the file ☐

Name of the cell: Part 8 – Capital gains dividend received in the year
Form: Sch. 6 - Summary of dispositions of capital property

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

Name of the cell: Line 395 – Amount
Form: Sch. 1 - Net income (loss) for income tax purposes

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

Name of the cell: Line 295 – Amount
Form: Sch. 1 - Net income (loss) for income tax purposes

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

Name of the cell: Part 1 – Net foreign non-business income earned in the year
Form: Sch. 21 - Federal and provincial or territorial foreign income tax

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

Name of the cell: Part 1 – Foreign non-business income tax paid for the year
Form: Sch. 21 - Federal and provincial or territorial foreign income tax

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

Name of the cell Canadian investment income – Other property income

Form Sch. 7 - Aggregate investment income and income eligible for th

SS16

jsassine - 2019-05-23

Keep this note when rolling forward the file

## 4 - OEB Staff - 113

Reference:

Exhibit 4 – Section 4.13, PILs Workform, Appendix 2-BA, Appendix 2-C

Preamble:

The depreciation expense for 2020 in Appendix 2-C is calculated as $11,817,000, Appendix 2-BA shows $11,500,628 and PILs Workform Tab T1 shows Amortization of tangible assets (additions for tax purposes under line 104) an amount of $10,799,612 for the test year.

Question:

a) Please explain the discrepancies in the numbers noted above, and provide updated PILs tax model tab T1 to align with the depreciation expense for the test year used elsewhere in the application.

---

Response:

a) The differences between Appendix 2-C and Appendix 2-BA are itemized within Appendix 2-C in column 'q' and all of the assumed differences are immaterial.

   Appendix 2-C contains a column with Appendix 2-BA figures which is labelled column 'p'. The differences that arise between the projected/estimated $11,817,000 figure and the actual depreciation highlight the differences in the assumptions used to derive the $11.8 million dollar figure and the actual depreciation. That $11.8 million figure is calculated assumed a half year rule of depreciation whereas actual depreciation is calculated when the asset is put into service.

   Both individual asset classes and the total variance between the assumed depreciation in column 'p' and the actual depreciation in Appendix 2-BA are all immaterial. The actual depreciation is correctly reported in both of those Appendices.

   The variance between the PILs Workform figure and Appendix 2-BA is the depreciation that is charged by the LDC to affiliates. Appendix 2-BA shows entity assets which includes LDC only assets and shared service assets. The PILs Workform and actual tax return only show the LDC portion of the depreciation. ENWIN charges the shared service portion of depreciation to affiliates and records that as non-utility revenue and expenses. For purposes of the Revenue Requirement Workform the lower depreciation amount used in the PILs Workform is used to derive the Revenue requirement.

## 4 - OEB Staff - 114

Reference:

Exhibit 4 – Section 4.13, PILs and Exhibit 9 Tab 2b.

Preamble:

The 2019 Budget Implementation Act (Bill C-97) was given royal assent on June, 21, 2019. Bill C-97 includes changes to the Income Tax Act that included new accelerated capital cost allowance (CCA) deductions on capital assets acquired after November 20, 2018. Generally speaking, the first-year CCA claim is three times the amount it would have been under the prior rules for these assets. The tax rates and rules assumed in Enwin Utilities' existing rates do not include these tax deductions.

Question:

a) Please prepare an analysis to calculate the revenue requirement impact for 2018 as a result of the new accelerated CCA rules and adjust the Account 1592 principal and interest balances accordingly.

b) Please provide the same analysis in a) above for calendar 2019 and confirm that EnWin Utilities will record these entries in Account 1592 during 2019. If this is not confirmed, please explain EnWin Utilities' position.

---

Response:

a) The accelerated CCA deduction was not utilized in 2018. Therefore, there is no impact for the 2018 year to account 1592 for principal or interest.

b) Using the information provided within the application for the 2019 Bridge Year, the impact on the revenue requirement in 2019 as a result of the accelerated deprecation is as follows:

**Revenue Requirement Workform**

| Particulars | Pre Bill C-97 | Post Bill C-97 | Change |
|---|---|---|---|
| **Determination of Taxable Income** | | | |
| Utility net income before taxes | 11,114,351 | 11,114,351 | - |
| Adjustments required to arrive at taxable utility income | - 126,682 | 2,232,679 | - 2,359,361 |
| Taxable income | 11,241,033 | 8,881,672 | 2,359,361 |
| **Calculation of Utility income Taxes** | | | |
| Income taxes | 2,978,874 | 2,353,643 | 625,231 |
| Total taxes | 2,978,874 | 2,353,643 | 625,231 |
| Gross-up of Income Taxes | 1,074,016 | 848,592 | 225,424 |
| Grossed-up Income Taxes | 4,052,890 | 3,202,235 | 850,655 |
| PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | 4,052,890 | 3,202,235 | 850,655 |
| Other tax Credits | - | - | - |
| **Tax Rates** | | | |
| Federal tax (%) | 15.00% | 15.00% | - |
| Provincial tax (%) | 11.50% | 11.50% | - |
| Total tax rate (%) | 26.50% | 26.50% | - |

***Based off of Revenue Requirement Workform Tab 6***

## 7 - OEB Staff - 115

Reference:

Exhibit 7, pp. 3-4, 9 EnWin_2017_Load_Forecast_Model_20190517.xls, Sheet Customer Data

Preamble:

On page 9 of Exhibit 7, EnWin Utilities states:

In a letter, dated June 12, 2015, the Board stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. ENWIN is not aware of any reason for the load profiles to have materially changed between the classes. As a result, ENWIN has not updated its load profiles at this time.

On pages 3-4 of Exhibit 7, EnWin Utilities documents that it is proposing to eliminate two existing customer classes and migrate the customers in those classes to other existing customer classes. Specifically, EnWin Utilities is proposing to eliminate the GS 3000-4999 kW (Intermediate) class and migrate the three existing customers to the GS 50-4999 kW class. EnWin Utilities is also proposing to eliminate the Large Use – Ford Annex class and migrate the customer to the Large Use – 3TS class.

Question:

a) What communication has EnWin Utilities had with each of the three customers in the Intermediate class who would be migrated to the GS 50-4999 kW class? Please indicate the communication that EnWin Utilities has done, and the reaction of the customers.

b) Please provide the bill comparison of a “typical” Intermediate class customer under EnWin Utilities current approved Intermediate Class rates relative to:

i. EnWin Utilities’ current approved rates for the GS 50-2999 kW class

ii. EnWin Utilities’ proposed rates for the GS 50-4999 kW class.

c) From the sheet “Customer Data” of EnWin_2017_Load_Forecast_Model_20190517.xls, EnWin Utilities documents 1,253 GS 50-2999 kW customers as of December 2017. EnWin Utilities is proposing to merge the 3 Intermediate (GS 3000-4999 kW) customers with these, and has reflected this proposal in its Cost Allocation model. The three Intermediate customers are already different from the existing GS 50-2999 kW class customers in having higher average monthly peak demands.

i. What is the average or median peak monthly demand for an existing GS 50-2999 kW class customer?

ii. How has EnWin Utilities reflected the integration of the GS 50-2999 kW and Intermediate classes into its proposed GS 50-4999 kW class in the Cost Allocation model? Has it done any direct allocation?

iii. How has EnWin Utilities satisfied itself that the allocators for both the existing GS 50-2999 kW and Intermediate customers are consistent enough so that its simple merging of class data is reasonable for purposes of cost allocation?

iv. How has EnWin Utilities satisfied itself that its proposed merger of these two classes and its approach to reflecting this proposal in the cost allocation study does not have unintended and adverse impacts on the allocation of costs for this or other customer classes? Specifically, what alternative analyses has EnWin Utilities done, such as a counterfactual analysis assuming no merger?

d) OEB staff note that Ford PowerHouse is an existing LU – 3TS customer of EnWin Utilities. What communication has EnWin Utilities had with the LU – Ford Annex customer regarding the migration of this customer to the LU – 3TS class. Please indicate the communication that EnWin Utilities has done, and the reaction of the customer.

e) Please provide the bill comparison the LU – Ford Annex customer for "typical" demand and consumption under EnWin Utilities current approved LU – Ford Annex Class rates relative to:

i. EnWin Utilities' current approved rates for the LU – 3TS class

ii. EnWin Utilities' proposed rates for the LU – 3TS class.

f) In Section 7.3.5, EnWin Utilities documents a direct allocation of costs for the existing LU – 3TS customers in the cost allocation model.

i. Does this direct allocation reflect the proposed integration of the LU – Ford Annex customer into the LU – 3TS customer class?

ii. If not, where are the costs and allocators for this customer reflected in the cost allocation model?

Response:

a) ENWIN's Key Accounts Supervisor is in the process of contacting the three existing customers in the Intermediate class. ENWIN will provide a copy of the customers' responses.

b) See response to VECC 45.

c) i. Average peak monthly demand for the GS > 50 – 4,999 kW class is approximately 200 kW.

   ii. No direct allocation was required in order to merge the GS > 50 – 4,999 kW class and the GS 3,000 – 4,999 kW class in the cost allocation model.

   iii. ENWIN proposes to merge the existing GS 50-2999 kW and Intermediate customers to be consistent with GS 50-4999 kW class used by many other LDCs in the province. For those LDCs with a GS 50-4999 kW class the cost allocation model is used to determine the allocated cost for this class and the cost allocation model determines the appropriate allocation factors for the GS 50-4999 kW class. ENWIN is using the same method to determine the allocated costs for the proposed GS 50-4999 kW class and believes it to be a reasonable approach.

   iv. For the rate classes that are being merged ENWIN understands the impact on these classes will reflect the weighted average of the separate classes being merged. ENWIN believes this is an acceptable outcome considering the reduction in rate classes will be more cost effective. In addition, a comparison of the main customer allocator (i.e. number of customers) and the main demand allocator (i.e. 4 NCP) in Tab E2 of the cost allocation between the merged case and status quo case indicates there is not a material movement in the value of the allocators for the other classes. This suggests to ENWIN the merged proposal does not have adverse impacts on the allocation of costs to other customer classes.

d) See response to AMPCO 40.

e) See response to AMPCO 40.

f) Yes, both in the cost allocation model filed with the Application, and the updated version of the model filed with the interrogatory responses, the direct allocation of costs for Ford Annex are included with the direct allocation of costs for the Large Use – 3TS class. Both classes of customers have dedicated transformer station assets of which the costs are directly allocated. Please reference Tab I9 Direct Allocation of the Cost Allocation Model.

## 8 - OEB Staff - 116

Reference:

Exhibit 8, Pages 14-16

Preamble:

EnWin Utilities states that there are two options for the MIST meter conversion:

A. Public carrier cellular communication. ENWIN had previously established a private APN with a public carrier that using compatible cellular modems would reliably backhaul the necessary meter data for this rate group.

B. Existing Smart Meter Advanced Metering Infrastructure (AMI) network. The vendor supported ENWIN to evaluate current infrastructure capacity and what optimization and/or level of investment is necessary to accommodate new meters in the future. At the time, the MIST communications technology was not available to meet the August 2020 deadline on our existing Smart Meter Network.

EnWin Utilities is proposing a new specific service charge for the option 1 as below:

ENWIN hereby makes application to the OEB for the creation of a new Specific Service Charge (being a monthly "Cellular Meter Reading Charge") in the amount of $7.50 to be applied to customers adopting

Option 1: Public Carrier Cellular Internet Communication.

OEB Staff notes from the installed base for the $7.50 monthly charge is 825 meters.

Enwin Utilities states that

Currently ENWIN has no reasonable estimate of the potential uptake of the various options to be proffered to the 966 demand metered customers however based on the communications cost comparisons we anticipate >80% cellular penetration.

Question:

a) Please explain how the installed base of 825 meters for the option 1 is derived and the basis of the assumption(s) used if any.

b) Please confirm the $7.50 monthly charge is charged to all demand customers who choose the option 1. If so, why.

Response:

a) ENWIN has used the assumption that when presented with the two connectivity options, the majority of customers will prefer option #1, with the main driver being the cost differential between the two options. The 825 meters is an estimate of 85% of the total demand customers needing to be converted (966 in total).

b) The $7.50 monthly charge is charged to all demand customers who choose option #1. The reason is that all other demand customers in ENWIN's service territory, including customers from the cohort of 966 referenced above that choose option #2, provide the dedicated phone line at their own cost.

## 9 - OEB Staff - 117

Reference:

Exhibit 9; DVA Continuity Schedule; GA Analysis Workform

Question:

a) OEB staff notes that the "Principal Adjustments during 2018" for Accounts 1588 and 1589 pertain to the reversals for the previous year (reconciling item 1b and 2b in 2017). OEB staff notes that there are no 1b and 2b reconciling items for 2018 on the GA workform. Please confirm that the 2018 variances presented on the DVA continuity schedule have been calculated in accordance with the APH Accounting Guidance dated February 21, 2019, i.e. all true-ups are reflected in EnWin Utilities' 2018 GL balance for disposition.

i. Did EnWin Utilities keep its books of accounts open long enough to include all true-ups for 2018 in 2018 balances?

b) OEB staff notes that EnWin Utilities is showing principal adjustments for Accounts 1508, Sub-account - Other (Productivity Initiatives) and Account 1518 in 2018. Please explain why these adjustments were made? Please explain the nature of these adjustments. If the adjustment is related to the prior periods, please breakdown the adjustment into transaction debits by each of the prior year.

c) OEB staff notes that EnWin Utilities is showing principal adjustments for Accounts 1531 and 1532 in 2018. Why were these adjustments made?

d) OEB staff notes that EnWin Utilities did show transactions in Accounts 1531 and 1532 up to year 2017.

i. Does EnWin Utilities have a balance in these accounts? If so, how much?

ii. Why is EnWin Utilities not proposing disposition of these accounts in this proceeding, as all Group 2 accounts must be disposed in a cost of service proceeding?

iii. Did EnWin Utilities follow the APH accounting guidance, including the March 2015 guidance for these accounts?

iv. The 2015 accounting guidance indicates that these accounts must be discontinued after a distributor has filed a DSP in a cost of service proceeding. Please confirm that EnWin Utilities would discontinue the use of these accounts in accordance with the OEB policy.

v. Please update EnWin Utilities' Group 2 rate rider including disposition of Accounts 1531 and 1532.

---

Response:

a) i.) ENWIN held the 2018 financial records open until March 2019 to capture the appropriate 2018 variances for the 1588 and 1589 with the exception of embedded generation which is settled on a lag basis. More explanation regarding the timing and recognition of the embedded generation is described within the response to Interrogatory OEB Staff-126. Otherwise, all true ups were reflected appropriately in accordance with the Accounting Procedures handbook and guidance provided on February 21, 2019.

b) Please refer to the responses to VECC-46, SEC-4 and SEC-34 for ENWIN's response to Account 1508 Productivity Initiatives adjustment details.

Please refer to the response to OEB Staff-120 for ENWIN's response to Account 1518 RCVA adjustment details.

c) Upon review of Appendix 2-FA during the completion of the Cost of Service application, ENWIN determined that the immaterial amounts recorded in these deferral accounts did not meet the qualifications of the 2.2.2.7 Chapter 2 requirement, nor did it meet the Ontario Energy Board Act, section 79.1 requirement and therefore the amounts were reversed.

Originally the balances represented costs for a 2nd SCADA instance for monitoring and controlling the FIT generators (and other points) that were connected to the distribution system.

The expenditure made was to facilitate monitoring and interruption of larger FIT and other generators should ENWIN need to temporarily re-configure the distribution system. The generators are only allowed to generate when they are connected to the station and feeder for which they have been given a generation capacity allocation. When ENWIN has many generators on the system and needs to reconfigure for operating reasons, without some means of controlling those generators remotely, ENWIN could not comply with this requirement as it would be impractical to manually interrupt the generators or to call all of them and request they go off-line. The main purpose of the expenditure was driven only by the generator connections so it was thought that all customers should not pay for something that was driven only by the generators. However, since the OEB has narrowly defined what is allowed in the deferral accounts, and it does not include these types of expenditures, ENWIN could not support keeping the investment amounts in the deferral Accounts 1531 and 1532.

d) i. and ii. ENWIN no longer has a balance in Accounts 1531 and 1532 as of December 31, 2018.

iii. Please see response to part c) above.

iv. ENWIN confirms it will discontinue use of these accounts in accordance with the OEB policy.

v. ENWIN no longer has a balance in 1531 and 1532. Therefore, disposition of these accounts is not necessary in the DVA Continuity.

## 9 - OEB Staff - 118

Reference:

GA Analysis Workform for 2018

Preamble:

The 2018 GA Analysis Workform shows a reconciling item #8 for the billing adjustment of $942,819.

Question:

a) Please provide a detailed explanation for this adjustment.

---

Response:

a) ENWIN has provided a revised GA Analysis Workform along with the Interrogatory responses. The original submission on April 26, 2019 had an adjustment line of $942,819 and was based on the information available within ENWIN's system at that time.

   In the original submission, the Non-RPP Class B kWh was derived by taking the total ENWIN load including Embedded Generation, less the RPP loss adjusted usage and Class A loss adjusted usage to obtain the Non-RPP Class B loss adjusted usage. This however is not the usage that was billed to the customer for GA.

   ENWIN subsequently had reporting and analysis developed to assist with this process. The revised GA Analysis Workform is now consistent with the OEB GA Analysis Workform instructions.

   Once the usage was entered it was apparent that the actual system losses were lower than the approved Total Loss Factors (TLF). ENWIN's 2017 system loss was 2.94%, while ENWIN's TLF is 3.77%. This resulted in a $496,351 difference in actual system losses compared to the TLF.

## 9 - OEB Staff - 119

Reference:

Exhibit 9, Section 9.4, pages 16 – 17; EnWin Utilities' 2009 CoS application EB-2008-0227 Settlement Agreement, Page 26

Preamble:

The settlement agreement of EnWin Utilities' 2009 CoS application stated that:

The Parties have agreed to the establishment of a new deferral account to be called the "Productivity Initiatives Deferral Account" to enable EWU to retain external experts and to facilitate stakeholder involvement to further EWU's productivity initiatives. The Parties propose that this account be a subaccount of 1508 "Other Regulatory Assets". The account would include expenditures of up to $100,000 per year paid to external persons, including both experts and stakeholders, to assist in developing or assessing productivity initiatives. Internal costs associated with such initiatives are included in the Base Revenue Requirement. Disposition of the Productivity Initiatives Deferral Account would be reviewed in EWU's next rebasing rate case.

EnWin Utilities is requesting recovery of $977,507 in Account 1508, Sub-account Other (Productivity Initiatives).

OEB staff summarizes the continuity schedule for this account using the 2018 DVA workform filed by EnWin Utilities as below:

| 2013 | | 2014 | 2014-2017 | 2018 | | | | 2019 | |
|---|---|---|---|---|---|---|---|---|---|
| Opening Bal. | Interest (Opening + 2013) | Transaction Debits | Interests | Transaction Debits | Principle adjustment | Interest | Interest adjustment | Interest | **Total Request** |
| 307,871 | 10,682 | 15,447 | 15,855 | 100,000 | 476,682 | 16,638 | 14,105 | 20,228 | **977,508** |

Question:

a) Please confirm the above table prepared by staff.

b) Please provide a breakdown of the 2013 opening balance of $307,871 to the prior years showing how this opening balance was derived by year.

c) For each of the transaction debits made in the account from 2009 to 2018, please discuss in detail the related productivity initiatives EnWin Utilities undertook and the funds spent on each activity.

d) Please confirm that the expenditures recorded in the accounts were 100% incurred and paid to the external persons but not the internal costs.

e) Did the external experts retained by EnWin Utilities make any recommendations with respect to the productivity initiatives?

i) If 'yes' to the previous question sub-part, what were they, and have they been implemented?

f) Did the productivity initiatives result in measurable outcomes and productivity gains?

g) Please discuss the productivity improvements that have been accomplished as a result of investing in the productivity initiative activities.

---

Response:

a) ENWIN has confirmed the above table prepared by OEB Staff is accurate with one adjustment of $1 on the ending balance, which is $977,507.

b) The 2013 opening balance in USoA 1508 was as follows:

**OEB 1508**
**Sub-Account: Productivity Initiatives Deferral Account**

| **Vendor** | **Description** | **Year** | **Amount** |
|---|---|---|---|
| | Various invoices subsequently reversed | | 7,871 |
| FMR | Future State Supervisor Role | 2010 | 100,000 |
| Optimus SBR Inc. | Operational Workforce Review | 2011 | 52,122 |
| Optimus SBR Inc. | Compensation Package Review | 2011 | 8,000 |
| Optimus SBR Inc. | Exec Leadership Strategy Workshop | 2011 | 39,878 |
| FMR | Stores and Supply Chain process | 2012 | 60,106 |
| Optimus SBR Inc. | Establishment of an Enterprise Project Mgmnt office | 2012 | 39,894 |
| **Total Principle Balance 2013** | | | **307,871** |

c) Please refer to Interrogatory - SEC #34 for the response to this question.

d) ENWIN has confirmed that the expenditures recorded in the accounts were 100% incurred and paid to the external consultants. No internal costs or allocations were applied to that account.

e) Please refer to Interrogatory - SEC #34 for the response to this question.

f) Please refer to Interrogatory - SEC #34 for the response to this question.

g) Please refer to Interrogatory - SEC #34 for the response to this question.

## 9 - OEB Staff - 120

Reference:

Exhibit 9, pages 16 to 18; Appendix 2-H Revenue Offsets

Preamble + Question:

**a) Account 1518 Retail Cost Variance Account**

EnWin Utilities is requesting a debit balance of $319,456 for disposition.

According to the APH:

This account shall be used monthly to record the net of: i) revenues derived, including accruals, from the following services: a) Establishing Service Agreements; b) Distributor-Consolidated Billing; and c) Retailer-Consolidated Billing. AND ii) the costs of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the **incremental costs** incurred to provide the services in (b) and (c) above, as applicable, and the avoided costs credit arising from Retailer-Consolidated Billing, including accruals. [Emphasis added]

i. Please confirm that all costs pertaining to RCVA Retailer causing variance in this account are incremental to the costs that were built in EnWin Utilities' rates for years 2009 – 2018.

ii. Please describe in detail EnWin Utilities' process for determining the amounts that were recorded in Account 1518 from 2009 to 2018.

**b) Revenue offsets**

i. Please confirm that EnWin Utilities has included the revenues in Appendix 2-H for retail services in its proposed distribution rates using the updated charges outlined in the EB-2015-0304 Decision and Order. If this is not the case, please explain why not.

ii. Please confirm that EnWin Utilities has implemented the new service charges outlined in the Decision and Order above with respect to retail services as of May 1, 2019, and has continued to accumulate the retail service cost and revenue variances in Accounts 1518 and 1548. If this is not the case, please explain why not.

iii. Please provide EnWin Utilities' best estimate of what the Account 1518 and 1548 balances will be as of the end of December 31, 2019, given year to date amounts and projections for the remainder of 2019.

iv. Does EnWin Utilities believe that it can reasonably forecast the December 31, 2019 balances in these accounts? If so, what would EnWin Utilities' position be with respect to disposing these amounts in the current application, as well as discontinuing these accounts effective January 1, 2020, given that EnWin Utilities would discontinue the use of these accounts?

v. If EnWin Utilities can reasonably forecast the December 31, 2019 balance in Accounts 1518 and 1548, please make this adjustment in the DVA continuity schedule and recalculate the amount requested for disposition and the associated rate riders.

vi. The use of Account 1518 and Account 1548 is predicated on the fact that retail service costs and revenues are excluded from distribution rates (and thus are recorded in variance accounts instead). Please confirm that EnWin Utilities excluded these items from the calculation of their distribution rates in their prior rate application. If this is not the case, please explain, in detail, the types of costs and revenues included in distribution rates versus the ones that have been recorded in these variance accounts.

**c) Account 1508 – Sub-account Pole Attachment Revenue Variance**

EnWin Utilities has proposed to dispose of the excess pole rental revenue earned up to December 31, 2018, which was recognized as a result of the charge increasing from $22.35 to $28.09 in September 30, 2018.

i. Please confirm that EnWin Utilities has included the most recent charge of $43.63, effective January 1, 2019, for the purposes of forecasting other operating revenue. If this is not the case, please explain why not.

ii. EnWin Utilities has proposed to discontinue this Sub-account in 2020. Please confirm that EnWin Utilities commenced charging the Pole Rental rate of $43.63 as of January 1, 2019, and has been recording the difference between $43.63 and $22.35 in this sub-account during 2019. If this is not the case, please explain why not.

iii. Does EnWin Utilities believe that it can reasonably forecast the December 31, 2019 balance in the Pole Rental Revenue account? If so, what would EnWin Utilities' position be with respect to refunding these amounts in the current application and discontinuing this sub-account effective January 1, 2020, rather than waiting until the subsequent cost-based application?

iv. Please provide EnWin Utilities' best estimate of what the Pole Rental Revenue sub-account balance will be as of the end of December 31, 2019, given year to date amounts and projections for the remainder of 2019.

v. If EnWin Utilities can reasonably forecast the December 31, 2019 balance in the Pole Rental Revenue account, please make this adjustment in the DVA continuity schedule and recalculate the amount requested for disposition and the associated rate riders.

Response:

a) i. ENWIN has confirmed that all costs pertaining to RCVA Retailer account 1518 are incremental to the costs that were built in ENWIN's rates for the years 2009 – 2018.

ii. ENWIN's process for determining the amounts that were recorded in Account 1518 from 2009 to 2018 are as follows:

Revenues specifically charged to retailers were isolated from other distribution revenue. The one time setup charge, the monthly retailer charge and the monthly per customer charge along with the billing charge were aggregated.

Expenses related to retailer activities were also isolated from other OM&A costs. Specifically, these expenses include charges from our external vendor for retailers, internal time spent billing and addressing retailer issues and a portion of the CIS support costs for retailer activities.

Those revenue and expenses related to retailer activities were isolated and tracked within the 1518 account.

b) i. ENWIN omitted the projected revenue relating to retailer services in Appendix 2-H.

ENWIN has subsequently calculated the amount of revenue using the updated charges outlined in EB-2015-0304 Decision and Order and revenue of $63,488 should have been recorded in the 2020 Test Year within Appendix 2-H. That amount has not been adjusted in the revised Chapter 2 Appendices.

While investigating the response to this question, ENWIN also identified an error in the OM&A as well related to this retailer activity. The 2020 Test Year OM&A balance had a $206,218 credit for retailer activities that should have been removed but was not. As a result, OM&A was understated by $206,218. Therefore, the net impact on ENWIN's 2020 test year is an overstatement of net income by $142,730.

ii. ENWIN has implemented the new service charges outlined in the Decision and Order above with respect to retail services as of May 1, 2019, and has continued to accumulate the retail service revenues in Accounts 1518 and 1548 until the end of 2019. As of May 1, 2019 ENWIN has elected to discontinue tracking the costs of RCVA per OEB Staff report EB 2015-0304 dated July 19, 2018. "The OEB does not see merit in electricity distributors continuing to track these variances....The elimination of the existing RCVAs should be concurrent with the implementation of the new RSCs in 2019."

iii. ENWIN's best estimate of what the Account 1518 and 1548 balances will be as of the end of December 31, 2019, given year to date amounts and projections for the remainder of 2019 is as follows:

1518: $285,309

1548: $33,080

This includes principle and carrying charges.

iv. ENWIN has reasonably forecasted the December 31, 2019 balances in these accounts and proposes to dispose of these amounts in the current application, as well as discontinuing these accounts effective January 1, 2020.

v. ENWIN has updated the DVA continuity schedule to include December 31, 2019 forecasted principal and carrying charge balances and recalculated the amount requested for disposition and the associated rate riders.

vi. ENWIN confirms that we have excluded these items from the calculation of the distribution rates in our prior rate application.

c) i. and ii. ENWIN has included the charge increase from $22.35 to $43.63, effective January 1, 2019, for the purposes of forecasting other operating revenue. The excess pole rental revenue earned has been allocated to account 1508 Sub-account Pole Attachment Revenue Variance for the year 2019.

iii. ENWIN believes it can reasonably forecast the December 31, 2019 balance in the Pole Rental Revenue account and proposes to dispose of this amount in the current application and discontinue this sub-account effective January 1, 2020.

iv. ENWIN's best estimate of what the Pole Rental Revenue sub-account balance will be as of the end of December 31, 2019 is $743,561.30.

v. ENWIN has updated the DVA continuity schedule to include December 31, 2019 forecasted principal and carrying charge balances and recalculated the amount requested for disposition and the associated rate riders.

## 9 - OEB Staff - 121

Reference:

Exhibit 9, Page 19

Preamble:

EnWin Utilities has stated that is not requesting disposition of Account 1557, Meter Cost Deferral Account – MIST Meters in this application. OEB staff notes that Group 2 accounts can only be disposed of in a rebasing proceeding. Also, the OEB policy is to dispose of all account balances in the cost of service proceeding.

Question:

a) Please provide justification for EnWin Utilities' proposal to not dispose of the balance in Account 1557 in this proceeding.

b) What is the balance in Account 1557 – Sub-account Capital, and Sub-account OM&A as of December 31, 2018?

c) What percent of MIST meter deployment was completed as of December 31, 2018?

d) Using the revenue requirement methodology (from the in-service date of the investment to January 1, 2010), similar to the one used in the disposition of smart meter deferral account balances, please calculate the rate riders for Account 1557.

e) Please roll the undepreciated capital cost into the rate base calculation for the test year, ensuring that the rate base is correctly reflected for the historic, bridge and test years.

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Response:

a) ENWIN's approach to the MIST meter implementation impacts is intended to be similar to its approach for smart meter implementation, such that upon completion of MIST meter installations, and through a separate proceeding, ENWIN would bring an application to the OEB to address stranded meter costs as well as the incremental revenue requirement for MIST meters using a model similar to the model approved in EB-2017-0132.

b) The balance in Account 1557 – Sub-account Capital as of December 31, 2018 is $444,364.40, and Sub-account OM&A as of December 31, 2018 is $0.

c) As of December 31, 2018, ENWIN had completed approximately 33.5% of MIST meter deployments.

d) Please see response to part a), above.

e) Please see response to part a), above.

## 9 - OEB Staff - 122

Reference:

Exhibit 9, Pages 21 to 22

Preamble:

EnWin Utilities is requesting a new deferral account to record a one-time net gain on sale of the property at 787 Ouellette Avenue. The "Net Gain" is defined by EnWin Utilities as the Actual Gain on the sale of the property, minus the water proportion, with the remainder shared 50% to the shareholder and 50% to the ratepayer. EnWin Utilities has defined the "Actual gain" as the proceeds from the sale of the property, minus the closing costs, minus the net book value.

Question:

a) EnWin Utilities has discussed the causation, materiality and prudence of the new deferral account and stated that the estimated gain of $576,062 from the sale of the property was removed from the other revenues in 2020. EnWin Utilities also states that the estimated gain is depending on the OEB's approval of EnWin Utilities' business plan. Is this asset included in the calculation of the rate base in this application?

> i) If so, please indicate what portion of this particular asset is included in the PP&E for the purpose of the rate base calculation (i.e. electricity vs. the water portion).
>
> ii) If "yes" to the previous sub-part of this question, please discuss how is EnWin Utilities proposing to account for the excess amount in its revenue requirement over the IRM term when the property would no longer be used for the electricity business (i.e. after it has been sold).

b) Why does EnWin Utilities think it is appropriate to share only 50% of the net gain with the ratepayer when the rate payer has paid 100% for it over the years when it was in EnWin Utilities' rate base?

c) Please confirm that the account would not be needed if the OEB does not approve the proposed business plan regarding the consolidation of the facilities.

d) Please provide a detailed draft accounting order, including details such as the purpose, effective date (from and to), how the amounts would be calculated and recorded in this account, when the account would be brought to the OEB for disposition, whether and how the carrying charges would apply.

Response:

a) The gain on sale is projected to occur in the 2020 Test Year. As part of the transaction, the net book value of the asset(s) have been removed in 2020 and therefore are not included in rate base for the 2020 Test Year.

b) The Ouellette administrative building was built during the 1960's. Since that time, the majority of its deprecation, maintenance and improvement costs have been paid for by a combination of electricity and water ratepayers. Prior to the amalgamation of ENWIN Powerlines Ltd. into ENWIN Utilities Ltd. on January 2, 2007, electricity customers had only paid a portion of building's shared services costs, while other water ratepayers and affiliate companies had paid the remainder.

   Since the amalgamation, the affiliates of ENWIN are charged a proportionate share of costs related to the Ouellette administrative building, including depreciation and a return on asset charge. As the affiliates have shared in the operating costs and deprecation of the building, it is ENWIN's position that the affiliates should also share in a portion of the net proceeds from the sale of the asset. It would be inequitable for the affiliates to have paid a share of the costs of the asset but to then receive none of the related benefits upon disposition. It should be noted that affiliates will also pay for their future share in the Rhodes operating center costs once all functions have been consolidated into that location, however, ENWIN's facility consolidation as a whole will result in a net benefit to ratepayers through reduced costs going forward.

   The most recent allocation of costs of the Ouellette location as between the electric utility and the affiliates was approximately 50/50. Thus, a 50/50 split of the gain was deemed equitable and fair between affiliates and the electricity business. The costs electricity ratepayers have paid related to the Ouellette administrative building were the result of the asset being used and useful in providing electricity service and did not create a property interest in the Ouellette administrative building. However, for ratemaking purposes, ENWIN deemed it fair to equally split the electricity portion of the gain between the shareholder and electricity ratepayers. A 50%/50% sharing of the net gain with ratepayers is intended to reflect the value created by ENWIN management associated with consolidating all employees to a single location, reducing costs over the long term.

c) As the Ouellette administrative building has been sold, a means to capture the portion of the gain attributable to electricity ratepayers is required. ENWIN believes a separate deferral account is an appropriate mechanism to capture this amount.

   If the facilities business plan is not approved, other changes to ENWIN's proposed Test Year revenue requirement and rate base would likely be required to reflect the outcomes of the OEB's decision. This would not be limited solely to the proposed deferral account.

d) ENWIN provided the details of its proposed draft accounting order for this new deferral account in its Exhibit 9 evidence update, filed May 17, 2019 (Section 9.5.1.1, p. 22).

   A proposed draft accounting order is provided as OEB Staff 122 - Attachment 1.

DRAFT

## ENWIN Utilities Ltd.

## DEFERRAL ACCOUNT FOR GAINS ON SALE OF PROPERTY RELATED TO THE COMPANY'S SITE CONSOLIDATION PLAN (SCP)

## DRAFT ACCOUNTING ORDER

The purpose of this account is to record the Net Gain ("Net Gain" is defined as the Actual Gain on the sale of the property, minus the amounts allocated to affiliates, with the remainder shared 50% to the shareholder and 50% to the ratepayer) on sale of the Ouellette Facility.

The Actual Gain on the sale of the property is defined as the proceeds from the sale of the land and building, minus the closing costs, minus the net book value.

ENWIN will establish the following deferral accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount SCP Gains Deferral Account

- Account 1508, Other Regulatory Assets, Subaccount SCP Gains Deferral Account Carrying Charges

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts. The effective date of the account would be from the date establishment of the account is approved by the Ontario Energy Board, and would not be closed until disposition of the account was approved by the Board on a final basis.

The sample accounting entries for the variance accounts are provided below.

A. Record the OEB-approved Net Gain to be cleared to customers through a rate rider:

- DR Account 4355 Gain on Disposition of Utility and Other Property
- CR Account 1508 Other Regulatory Assets, Subaccount SCP Gains Deferral Account

B. Record the carrying charges based on the net of the balances in Account 1508 subaccount SCP Gains Deferral Account. The carrying charges are determined using simple interest applied on the monthly net opening balances:

- DR Account 6035 Other Interest Expense / CR 4405 Interest and Dividend Income
- CR/DR Account 1508 Other Regulatory Assets, Subaccount SCP Gains Deferral Account Carrying Charges

## 9 - OEB Staff - 123

Reference:

Exhibit 9, Page 23; the OEB letter issued on February 9, 2016

Preamble:

In an OEB letter dated February 9, 2016 where Account 1508 – OEB Cost Assessment Variance Account was established, stated the following:

Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or customer IR) incorporating an updated forecast of cost assessments.

…….Regulated entities are expected to seek disposition of the variance account balances when their rates, payment amounts or fees, as applicable, are next rebased/reset, and the accounts will be closed to any further entries at that time.

Question:

a) In light of the above OEB letter, please provide EnWin Utilities' rationale for its proposal to continue this account.

---

Response:

a) Account 1508, Sub-Account OEB Cost Assessment Variance does not require continuation. ENWIN will amend its request in Exhibit 9, Section 9.5.2 of the Application accordingly.

## 9 - OEB Staff - 124

Reference:

Exhibit 9, Page 23: EnWin Utilities' proposal for Continuance of Smart Grid Accounts 1534 & 1535; the OEB Accounting Guidance issued in March 2015

Preamble:

The OEB accounting guidance of March 2015 stated the following:

Under the most recent policy direction of the OEB, the existing deferral accounts for renewable generation connection and smart grid development are to be discontinued following the approval of a rate order that is underpinned by a distributor's first consolidated DS plan. Additionally, the distributors filing cost of service applications in 2014 and subsequent years must include proposals for disposition of any existing balances relating to………deferral Account 1534 Smart Grid Capital Deferral Account and Account 1535 Smart Grid OM&A Deferral Account

Question:

a) In light of the above OEB guidance, please provide EnWin Utilities' rationale for its proposal to continue the Smart Grid accounts 1534 and 1535.

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Response:

a) Account 1534 (Smart Grid Capital Deferral Account) and Account 1535 (Smart Grid OM&A Deferral Account) do not require continuation. ENWIN will amend its request in Exhibit 9, Section 9.5.2 of the Application accordingly.

## 9 - OEB Staff - 125

Reference:

Exhibit 9, Pages 25 to 26

Preamble:

EnWin Utilities provides the Table below for the Non-RPP billing determinants:

| Line No | Rate Class | Percent of 2018 kWh | 2020 Non-RPP kWh | Percent of 2018 kW | 2020 Non-RPP kW |
|---|---|---|---|---|---|
| 1 | RESIDENTIAL | 2.81% | 15,610,676 | - | - |
| 2 | GS<50 KW | 13.91% | 27,195,353 | - | - |
| 3 | GS>50 - 4,999 KW | 81.51% | 742,476,099 | 80.83% | 2,071,136 |
| 4 | LARGE USE REGULAR | 100.00% | 281,863,540 | 100.00% | 542,339 |
| 5 | LARGE USE 3TS | 100.00% | 277,391,364 | 100.00% | 528,993 |
| 6 | STREET LIGHT | 99.72% | 6,400,935 | 99.72% | 18,379 |
| 7 | SENTINEL | 8.59% | 63,183 | 8.53% | 174 |
| 8 | UNMETERED SCATTERED LOAD | 96.01% | 2,133,170 | - | - |
| 9 | **Total** | | **1,353,134,321** | | **3,161,021** |

It is not clear to the staff how Table 9-14 is calculating the load forecast. For example the columns “Percent of 2018 kWh” and “Percent of 2018 kW” do not each add to a total of 100%.

Question:

a) Please clarify and provide an amended Table 9-14 as necessary.

Response:

a) The columns “Percent of 2018 kWh” and “Percent of 2018 kW” represent the relationship between 2018 Non-RPP billing determinants as a percentage of 2018 total actual billing determinants. These percentages were then applied to the 2020 billing determinant forecast to derive the billing determinants listed in the “2020 Non-RPP kWh” and “2020 Non-RPP kW” columns.

For example, in 2018, Non-RPP kWh represented 2.81% of 2018 Actual residential kWh billing determinants. 2.81% was then applied to the 2020 residential billing determinant forecast of

555,916,913 kWh to derive the 2020 forecast Non-RPP billing determinant value (please note the table above would encompass the results using unrounded values).

## 9 - OEB Staff - 126

Reference:

Exhibit 9, Page 32

Preamble:

EnWin Utilities has indicated that settlement for embedded generation is performed with a one month lag and is based on the balance in Enwin Utilities' general ledger for generation (MicroFit and FIT) less Cost of Power.

Question:

a) Are EnWin Utilities' commodity account balances as of December 31, 2018 proposed for disposition, presented on trued-up costs basis?

b) When was the embedded generation related Cost of Power for December 2018 settled with the IESO, and when was it recorded in EnWin Utilities' general ledger?

When were the embedded generation and Class A volumes for December 2018 reported to the IESO for the purpose of the determination of Charge Type 148 (per OEB's February 21, 2019 Accounting Guidance, Section IV)? And when was this recorded in EnWin Utilities' general ledger?

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Response:

a) ENWIN Utilities' commodity account balances as of December 31, 2018 proposed for disposition are presented on trued-up costs basis with the exception of Embedded Generation. See response to part b) below for more detail.

b) The embedded generation related Cost of Power for December 2018 was settled with the IESO in the January 2019 IESO Settlement (filed by the fourth business day of February 2019). This was recorded in ENWIN's general ledger in January 2019 (Charge Type 1412) and therefore not included in the 2018 balance.

   After ENWIN filed this Application, on July 11, 2019, the Board issued its Q&A Guidance on Accounts 1588 and 1589, which outlines that settling embedded generation Cost of

Power with a lag is not acceptable. ENWIN plans to implement an estimation process for embedded generation with its August 2019 IESO Settlement.

The reporting of embedded generation and Class A volumes for December 2018 for the purposes of determining of Charge Type 148 was done in the December 2018 IESO Settlement (filed by the fourth business day of January 2019). The Charge Type 148 reflected on the IESO bill for the December 2018 period was recorded in ENWIN's general ledger in December 2018.

## 9 - OEB Staff - 127

Reference:

Updated Evidence received June 11, 2019; Appendix 2-EA

Preamble:

The updated evidence states:

For Account 1575 IFRS-CGAAP Transitional PP&E Amounts, EnWin Utilities originally filed Appendix 2-EA using 2018 forecast values. The value included in KPMG's audit report represents actual values for 2018. EnWin Utilities is working on updating Appendix 2-EA with 2018 actuals and will be prepared to file this updated information during interrogatory responses.

OEB staff notes from Appendix 2-EA that the net depreciation from 2011 to 2019 for PP&E value under MIFRS matches with the addition in accumulated depreciation of 2011 to 2019 before excluding the fully allocated depreciation for transportation and stores equipment. Please see below for 2019 as an example:

| | 2019 Bridge Year |
|---|---|
| | MIFRS |
| Net Depreciation per Appendix 2-EA | (12,779,291) |
| Net Depreciation per Appendix 2-BA (cell k723) | (12,498,480) |
| **Diff** | **(280,811)** |

| **Fully Allocated Depreciation per Appendix 2-BA** | 2019 Bridge Year |
|---|---|
| Transportation | (251,760) |
| Stores Equipment | (29,051) |
| **Total fully allocated depreciation** | (280,811) |

Question:

a) Please confirm the above staff observation as illustrated in the tables.

i) If confirmed, please explain why EnWin Utilities is not using the fully allocated depreciation for the purpose of calculating the balance in Account 1575.

b) If applicable, please file an updated Appendix 2-EA, as well as the underlying Appendices 2-BAs (fixed asset schedules) and 2-Cs (depreciation schedules) to support the balance for disposition in Account 1575.

Response:

a) ENWIN confirms the above staff table amounts are correct as report in Appendix 2-EA and 2-BA.

i. The $12,779,291 reported on Appendix 2-EA is the amount that impacts the net book value which is the amount to be used in the evaluation. The $12,498,480 reported as net depreciation in Appendix 2-BA is the amount of the depreciation collected in the revenue requirement. The difference between the two amounts is collected in OM&A in the revenue requirement. The gross depreciation is used for NBV purposes (ie. rate base calculations). The net depreciation is used in the revenue requirement.

b) Based on the rationale provided above, ENWIN did not amend Appendix 2-EA, 2-BA and 2-C.

## 9 - OEB Staff - 128

Reference:

The updated evidence filed on June 11, 2019; Appendix 2-EA

Preamble:

The updated evidence filed by EnWin Utilities on June 11, 2019 includes an audit report for EnWin Utilities' 2018 DVA balances. Staff notes that the audit opinion on page 1 of the KPMG audit report states:

We have audited the accompanying schedule of Group 1 regulatory balances of EnWin Utilities Ltd. (the entity) as at December 31, 2018 and notes to the schedule including a summary of significant accounting policies (Hereinafter referred to as the "schedule").

In our opinion, the accompanying schedule as at December 31, 2018 of the Entity is prepared, in all material respects, in accordance with Article 490 of the Accounting Procedures Handbook for Electricity Distributors as published by the Ontario Energy Board effective January 1, 2012 and Guidance and Frequently Asked Questions issued by the Ontario Energy Board from time to time.

OEB staff notes that the 2018 audited balance for Account 1575 is (21,594,606.03).

Question:

a) Please provide the materiality threshold used in the audit of the 2018 DVA balances.

b) Please explain how EnWin Utilities has ensured that the forecasted 2019 transactions that are recorded in Account 1575 and to be disposed in this rate application are reasonably accurate.

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Response:

a) Materiality was set at $2,500,000 for the audit report referenced above.

b) ENWIN has mitigated the risk associated with the projected values within Appendix 2-EA by updating Account 1575 with 2018 Actual activity and will be using the same 2019 capitalization rates in the actual financial reporting compared to Appendix 2-EA. Predictions about future additions and disposal activities during the 2019 year have been discussed with the technical and operational experts within the organization in order to come up with the best available information in order to forecast the 2019 ending balance.