1 - AMPCO - 1

Reference:

Exhibit 1: Administration P19

Question:

Please provide the affiliation of each of the five independent Directors of the Board.

Response:

The five independent Directors of the Board are not directors of any other affiliate of ENWIN Utilities Ltd., nor to ENWIN's knowledge are there any other board interlocks.

1 - AMPCO - 2

Reference:

Exhibit 1: Administration

Question:

Please provide a copy of the business plan or other correspondence that was approved by the ENWIN's Board of Directors regarding the investment levels in this application.

Response:

Please find appended to this response a copy of a board report titled "*ENWIN Utilities Ltd. (EWU) 2019-2024 Business Plan and Operating and Capital Budgets*" dated August 28, 2018 and subsequent minutes approving the recommendations contained in the report by the ENWIN Utilities Ltd. Board of Directors.

AMPCO 2 - Attachment 1 – Copy of report titled "*ENWIN Utilities Ltd. (EWU) 2019-2024 Business Plan and Operating and Capital Budgets*" dated August 28, 2018;

AMPCO 2 - Attachment 2 – Minutes of Board meeting held September 17, 2018 approving recommendations contained in above report.

AGENDA SUBMISSION

IN CAMERA

To: EWU A&F Committee and Board of Directors
WCU A&F Committee and Board of Directors

August 28, 2018

From: Byron Thompson

Re: ENWIN Utilities Ltd. (EWU) 2019 – 2024 Business Plan and Operating and Capital Budgets

Background

The 2019 – 2024 Business Plan and Operating and Capital Budget report attached to this report provides a comprehensive summary of the operating and capital budget presented for review and approval by the Audit Committee and Board. The report provides an executive overview, summary of financial highlights, key budget assumptions, detailed operating budget financial statements, variance analysis and details of the capital budget as well as details of certain major operating expenses such as legal and consulting fees. Detailed explanations of capital expenditures planned for 2019 and 2020 are provided at the end of the report for additional information.

Similar to prior years, the budget was built at a departmental level with input from operational Managers, Directors and finance staff followed by multiple levels of review by finance staff, senior management. Prior to commencement of budget meetings parameters were set to encourage cost control and continue recent favourable cost trends to allow for optimal profitability together with minimal rate increase for our customers.

Unlike prior years, Management is seeking Board approval for two years; 2019 and 2020 in order to have Board approved budgets to include in its 2020 Cost of Service (COS) application in April 2019. While Management has taken care to ensure the attached operating and capital budget will suit both our internal needs and are reasonable for the COS application, it is important to note that additional detailed analysis is required for the COS application which may necessitate some changes to this budget. Ultimately as the detailed documentation is prepared for the application, and continued customer feedback is sought, some changes to capital programs for instance may make sense for which we presently do not have information. Should additional information become available, it may be necessary to refresh certain elements of either the capital or operating budget accordingly to ensure our records are in sync. If that is required Management will report back to the Board later in the year, or early next year and seek approval for any necessary updates to this budget.

Analysis

A high level summary of the 2019 and 2020 budget and projections for 2021 to 2024 and key assumptions is provided as follows:

- 2019 Net income of $8.7 million, 2020 Net income of $10.5 million
- 5.76% Rate increase estimated and modelled for 2020 the COS year, and 1.3% for all other years. These rates will ultimately be determined by the OEB.
- For illustrative purposes settlement of major OEB prescribed Group II rate riders is presented as below. These amounts and amortization periods may differ.
    - IFRS /CGAAP transition rate rider is amortized over 5 years at rate of $4.7 million per year. Under MIFRS this is applied to the balance sheet not impacting earnings.
    - The HST/ PST rate rider is estimated to be $4.5 million and has been amortized as a revenue reduction for EWU at $1.5 million per year for 2020, 2021 and 2022 impacting net income in those years.
    - Since we have presented the IRFS/CGAAP transition rate rider as being amortized over 5 years working capital or interest will apply in the amount of $7.1 million in total, or annually $1.42 million per year. This amount is presented as a revenue reduction, impacting income also.
    - Ultimately for all the above rate riders, the amount and disposition period will be determined through the COS application process by the OEB.
- Capital expenditures (net of contributed capital) provided in the budget are as follows:
        - 2019 = 21.39 million
        - 2020 = 19.95 million
        - 2021 = 18.58 million
        - 2022 = 17.77 million
        - 2023= 18.75 million
        - 2024 = 17.99 million

  Average capital expenditures from 2009 to 2017 were $17.59 Million
- Dividends of $4.0 million payable by EWU to WCU are projected for each year.
- The sinking fund is projected as being transferred to WCU, and funded annually via loan repayment from EWU to WCU in the amount of $1.2 million per year. A separate report will be provided to the Board on this matter and other capital structure considerations.
- As a result of the above noted assumptions, cash balances in EWU will reduce from the 2018 projected level of $32.4 million to less than $1.0 million by the end of 2024. While this represents a significant reduction in liquidity, by this time EWU equity is projected to have grown to approximately $ 161 million and outstanding debenture

debt will be $51 resulting in a debt to equity ratio of 31.7% compared to the OEB prescribed rate of 150%. Lines of credit are available at the WCU level in the amount of $75 million to ensure EWU has ample liquidity to continue to fund its infrastructure needs and continue its dividend payment to the City.

Dividends

Similar to 2018, it is projected that EWU earnings and cash flow are sufficient for payment of dividends by EWU to Windsor Canada Utilities Ltd. ("WCU") with a reasonable margin of safety. Accordingly for efficiency of administration (both Board and Staff) and to allow for a more predictable pattern of payment, management proposes that for 2019, the base level of dividends of $4.0 million by EWU to WCU be approved by the Board along with approval of the Budget.

Consistent with historic practices, Management and the Board will review the year end results in April following each year end, and determine if any additional dividends in excess of $4.0 million should be paid.

EWU performance relative to the regularly paid dividends can be monitored as the year progresses through the quarterly financial reports provided to the Board. In the event of adverse financial performance, dividends previously approved but not yet paid could be repealed.

The necessary mechanics of this proposal are included in the recommendation below.

While management is seeking budget approval for 2019 and 2020, it is proposed that dividends for 2020 be approved in the fall of 2019 when more information on the status of the COS application is known.

RECOMMENDATION:

EWU Audit & Finance Committee

That the ENWIN Utilities Ltd. 2019 – 2024 Business Plan and Operating and Capital Budgets be received;

And that the ENWIN Utilities Ltd. 2019 – 2024 Business Plan and Operating and Capital Budgets be recommended to the EWU Board of Directors for approval.

And that the Committee recommends to the Board that four quarterly dividends of $1,000,000 each, be declared and paid to Windsor Canada Utilities Ltd. for 2019, effective March 28, 2019, June 27, 2019, September 26, 2019 and December 19, 2019.

EWU Board of Directors

That the ENWIN Utilities Ltd. 2019 – 2024 Business Plan and Operating and Capital Budgets be approved, as recommended by the EWU Audit & Finance Committee.

And that four quarterly dividends of $1,000,000 each, be declared and paid to Windsor Canada Utilities Ltd. for 2019, effective March 28, 2019, June 27, 2019, September 26, 2019 and December 19, 2019, as recommended by the EWU Audit & Finance Committee.

WCU Audit & Finance Committee and Board

That the ENWIN Utilities Ltd. 2019 – 2024 Business Plan and Operating and Capital Budget report be received.

Vice President Finance and CFO

President and CEO

Business Plan & Operating and Capital Budgets 2019 – 2024

ENWIN

Table of Contents

OVERVIEW

ENWIN Utilities Ltd.'s 2019 – 2024 Business Plan which includes our Operating and Capital budgets has a theme of efficient operations, investment in infrastructure and resetting our regulatory position which includes returning balances owed to customers.

ENWIN continues to focus on providing value to customers and the shareholder. One way of achieving that is focusing on operational efficiencies and excellence. This budget has cost savings embedded in it such as the site consolidation and also has a plan to reduce headcounts through attrition in the near term.

This plan allows for continuous focus on customer satisfaction by investment in our infrastructure to continue to improve our system's safety and reliability while also investing in solutions that will enhance the customer's experience.

Rates paid by our customers are assumed to increase marginally in 2019. The 2019 period along with 2021-2024 are assumed to use the IR model to set rates, which assumes an inflationary increase less an efficiency factor. Therefore the assumed increases to ratepayers are less than inflation in those years.

The budget assumes that ENWIN will file a Cost of Service ("CoS") application with rates effective January 1, 2020. This is scheduled to be the first time ENWIN will re-base since 2009. The CoS process allows for regulatory balances to be settled which will change ENWIN's cash position throughout the projection period. The actual CoS application has not been completed at this time, but the base increase has been estimated as 5.76%. That rate was determined using the values projected in this budget along with some assumptions about how some of the rate models and applications might look when the CoS process is completed. With that said, the preliminary review of our rates suggests that the actual rate impact to the customer may be a reduction of approximately 5%. The reason for the reduction is due to the settlement of regulatory liabilities. Our models have set up within this budget model to assume that ENWIN will settle these balances over five years and is one of the main factors why cash moves into an overdraft position. It is important to remember that the assumed rate increase will not be known until the actual CoS application has been completed and settled on and any increases or decreases may vary by rate class.

2019 & 2020 OPERATING AND CAPITAL PLAN HIGHLIGHTS

✓ **Strengthen financial position**

- ✓ 2019 & 2020 Net income – MIFRS ($8.7 and 10.5 million respectively) – those are lower than 2018 because in 2018 a one-time tax refund is expected.
- ✓ Cash positive (2019 - $27.3 million and 2020 - $19.5 million) – strong liquidity over that period even with expected higher capital spending in 2019 and settlements of regulatory liabilities.

✓ **Investment in capital**

- ✓ Investment in hydro gross assets (2019 - $21.7 million, 2020 - $19.7 million).
- ✓ Investment in IT and cyber security (2019 - $4.6 million, 2020 - $3.5 million).

✓ **Focus on Operational Efficiencies**

- ✓ Operating expenses are projected to grow slower than inflation over the long term.

The CoS costs are included in 2019 and are distorting the trends. The chart below normalizes the actual proposed Operating Expense increases:

Description	(in $000's)					
	2017 Actual	2018 Forecast	2019 Budget	2020 Budget	2021 Projection	2022 Projection
Operating Expenses – per budget	27,605	29,101	29,769	29,522	29,701	30,066
CoS costs	-	-	(807)	-	-	-
Normalized Operating Expenses	27,605	29,101	28,962	29,522	29,701	30,066
Year over year % change	-	5.4%	(0.5%)	1.9%	0.6%	1.2%

- ✓ Rate increases on an IR basis for all years with the exception of 2020 (CoS assumption).
- ✓ Reduction of headcount through attrition.
- ✓ Favourable debt financing.

✓ **Increasing shareholder value**

- ✓ Stable and consistent dividend.
- ✓ Increase in total assets of $21.3 million and increase in shareholder equity of $20.0 million from 2017 to 2020.

FINANCIAL HIGHLIGHTS

($000's)	2017 Actual	2018 Forecast	2019 Budget	2020 Budget	2021 Projection
Distribution Revenue	**50,898**	**52,798**	**53,382**	**51,587**	**52,294**
Other miscellaneous revenue	12	(407)	(354)	2,590	2,643
Net Services Revenue	724	679	660	633	622
Operating expenses	(27,605)	(29,101)	(29,769)	(29,522)	(29,701)
Operating Income	**24,029**	**23,969**	**23,919**	**25,288**	**25,858**
Other expenses	(13,049)	(13,042)	(12,804)	(11,866)	(12,823)
Net Income before taxes	10,980	10,927	11,115	13,422	13,035
Income taxes	(3,740)	1,751	(2,390)	(2,886)	(2,803)
Net Income – MIFRS	**7,240**	**12,678**	**8,725**	**10,536**	**10,232**
Regulatory & OCI Adjustments	(3,900)	(4,861)	(992)	(630)	(4,731)
Net Income – IFRS	**3,340**	**7,817**	**7,733**	**9,906**	**5,501**
Capital Expenditures (net)	14,061	14,533	21,386	19,951	18,577
Dividend	4,000	4,000	4,000	4,000	4,000
Dividend payout ratio	55.2%	31.6%	45.8%	38.0%	39.1%
Debt / Equity – F/S (MIFRS)	0.44	0.41	0.39	0.38	0.36
FTE – electricity only	198	195	195	196	195
Assumed rate increase	1.3%	0.6%	0.6%	4.3%	1.3%
Return on Equity – f/s (MIFRS)	5.8%	10.3%	6.7%	7.8%	7.2%
Return on Equity – f/s (IFRS)	5.1%	5.5%	5.3%	6.2%	3.4%
Return on Equity – Regulatory (OEB calc)	2.6%	2.0%	2.9%	6.0%	5.8%

ASSUMPTIONS

- Electricity Rates – Revenue assumptions:
  - # customers = 88,262;
  - Consumption for budget years were based off of a weather normalized model provided by an external consultant which will be used in our CoS application;
  - Rate increase estimates (actual increases to be determined by the OEB):
    - IRM 2019 – 0.6% and 2021-2024 = 1.3%;
    - CoS = 5.76% on January 1, 2020.

- Rate Riders
  - Existing rate riders are accounted for in this budget. Those adjustments impact the balance sheet only (reduction to regulatory liabilities and reduction to cash).
  - Estimates have been made about certain Group 1 balances (regular cost of electricity and short term timing items) settling over the 2019-2020 period. Again, these adjustments would not impact the income statement but will result in a reduction in cash.
  - Two significant regulatory balances are only able to be settled through a CoS.
    - The HST balance is assumed to accumulate to $4.5M by the end of 2019 and that amount is assumed to be a reduction to revenue over the 2020 - 2022 periods or $1.5M per year.
    - The IFRS/GAAP conversion balance is assumed to be $23.6 million by the end of 2019. This amount is being accrued every year ($4.72M per year) in miscellaneous revenue so once this balance is disposed of, the impact will be a reduction in cash and regulatory liabilities (no future impacts to the income statement after 2020).
      - There is however an interest/carrying charge that has to be accrued. That is estimated to be $7.1 million over 5 years, or $1.4M per year. That amount of interest will directly reduce revenue for the periods 2020 - 2024 as well.

The chart below summarizes the impact of those regulatory adjustments on ENWIN's revenue.

Description	(in $000's)					
	2019 Budget*	2020 Budget	2021 Projection	2022 Projection	2023 Projection	2024 Projection
Normalized Distribution Revenue	51,538	54,505	55,212	55,931	56,658	57,395
% change		5.76%	1.3%	1.3%	1.3%	1.3%
Add: Rate Rider Impact	1,844	(2,918)	(2,918)	(2,918)	(1,422)	(1,422)
Net Distribution Revenue on the F/S – see budget	53,382	51,587	52,294	53,013	55,236	55,973

*$2,217 is also recorded as a reduction to revenue in 2019 as a result of the IFRS/GAAP conversion but it is recorded in the miscellaneous revenue line instead of distribution revenue as per the OEB.

The actual amounts and periods in which these rate riders and adjustments are settled will be negotiated and decided by the OEB at a future date. The actuals amounts may differ compared to than the amounts presented in this budget depending on those negotiations.

ASSUMPTIONS (continued)

→ Inflation is assumed to increase by 2.0% in each of the years.

→ Salary and benefit assumptions were as follows:
  - Salaries and benefits are budgeted at the specific benefit level and may differ individually but an overall increase of 2% was assumed.

→ FTE - Attrition – the Plan assumes that certain positions will not be filled once a retirement occurs.
  - Total FTE in this budget are assumed to be: 2018 – 333; 2019 – 330 and 2020 – 328. The portion attributed to electricity is 2018 – 195; 2019 – 195 and 2020 – 196.

→ Interest rate and investment return assumptions were as follows:
- Debenture interest = 4.134%.
- Interest on deposits were assumed to be 2.20%

→ The sinking fund was assumed to be moved to Windsor Canada Utilities Ltd. effective December 31, 2018. The fund was used to pay off the intercompany debt that previously existed between ENWIN Utilities Ltd. and Windsor Canada Utilities Ltd. A separate report will be presented to the Board regarding this capital restructuring plan.

→ One project that is focused on improving operational efficiencies while reducing costs is the site consolidation project. The budget contains assumptions about consolidating operations into the existing Rhodes facility. A separate Board report was provided descripting this project and the impacts of on the budget are projected as follows:

Site Consolidation	(in ($000's))			
	2018 Forecast	2019 Budget	2020 Budget	Total
Capital Cost	$ -	$ 2,062	$ 1,150	$ 3,212
Incremental Operating Costs (one-time)	96	12	180	288
Total Spending	$ 96	$ 2,074	$ 1,330	$ 3,500
Annual Operating Savings (after 2020)				$388

*offset by proceeds on sale and the gain

→ Income tax rate applicable is 26.5%, and the effective rate for EWU is estimated to be 21.5% based on timing differences between accounting and taxable income.

→ The presentation and allocation of vehicle expenses has been changed in the 2019 budget and for all future years. Historically EWU recorded vehicle expenses directly on it's own line on the income statement. For 2019 and subsequent years, no direct vehicle expense is presented. Consistent with OEB requirements, vehicle expenses are fully allocated across the income statement accounts and to capital as it applies.

ASSUMPTIONS (continued)

→ Dividends – assumed to pay $4 million annually in dividends.
The Dividend payout ratio for the years is as follows:

	2017 Actual	2018 Forecast	2019 Budget	2020 Budget	2021 Projection
Net Income (MIFRS)	$7,240	$12,678	$8,725	$10,536	$10,232
Dividend	$4,000	$4,000	$4,000	$4,000	$4,000
Dividend Payout*	55.2%	31.6%	45.8%	38.0%	39.1%

**Target range is between 25% - 55% (this is under review)*

→ No Merger & Acquisition activity planned or modelled.

RISKS

Environmental/Macro Factors

→ Regulatory Changes:

- Changes in the industry such as the Fair Hydro Plan may significantly impact the operations of the electricity industry within Ontario.

  For example changes in billing requirements may require more investment or may impact the cash flows of ENWIN if disconnections and arrears procedures are modified.

→ Political Factors:

- The new provincial government's commitment to reduce electricity rates may have impacts on the operations of ENWIN.

→ Electricity Rates:

- The 2020 rate assumed within the CoS application may change. This could include a combination of timing and/or the amount of cost recovery requested.
- For IFRS reporting purposes, we have assumed certain regulatory balances would be settled. If those assumptions need to change, the IFRS net income along with the MIFRS balance sheet may also need to be updated. As a reminder regulatory liabilities and assets are recorded on a cash basis rather than an accrual basis. As a result, the impacts of rate riders will impact the net income of the entity until such time that a new IFRS allows for the accrual of those assets/liabilities.

→ Industry Consolidation:

- Consolidations within the industry may increase and result in more pressure to regionalize and/or consolidate.

RISKS (continued)

ENWIN Specific Risks

→ FTE – Attrition:

- Timing of retirements is not guaranteed and although there are plans to reduce total headcount through attrition, there is a risk that the timing may vary and therefore cause variances in certain years. With a significant portion of ENWIN's workforce approaching retirement age, the attrition levels depicted in this budget carry some risks as additional headcount may be required until apprentices are appropriately trained to ensure adequate service levels.

→ Capital Projects:

- In many cases, the timing of projects is contingent upon several external factors. If delays occur or projects are reprioritized (internally or externally), that may impact the ability of the LDC to complete projects in the original year they were budgeted.

→ IFRS

- IFRS 16 – Leases become effective in 2019. For purposes of the budget, the existing lease costs were fully allocated using burdens. A review of the existing leased vehicles and options is currently underway and may result in changes once the full review and analysis is complete.
- IFRS 14 – Regulatory Deferral Accounts – it is anticipated that a new exposure draft will be issued outlining the opportunity for regulated entities to record regulatory assets and liabilities on the balance sheet. The exact timing and impacts of this exposure draft is unknown at this time and will impact the IFRS financial statements rather than the MIFRS financial statements. This budget assumes no change to MIFRS or IFRS.

→ Forward looking projections:

- The Board is being asked to approve the 2019 and 2020 Budget and to assist with that, a 4 year projection has also been provided. There is risk that assumptions and business decisions may change over that time but this projection assumes a stable business environment with modest inflationary increases.

APPENDICES

FINANCIAL STATEMENTS

Appendix A

ENWIN Utilities Ltd.
2019-2020 Balance Sheet Budget
For the period ending December 31st
(In thousands of Canadian dollars)

	2017 Actual MIFRS	2018 Forecast MIFRS	2019 Budget MIFRS	2020 Budget MIFRS	2021 Projection MIFRS	2022 Projection MIFRS	2023 Projection MIFRS	2024 Projectior MIFRS
Assets								
Current Assets								
Cash and Bank	$ 26,205	$ 32,350	$ 27,275	$ 19,480	$ 12,128	$ 7,362	$ 3,199	$ 298
Accounts Receivable	20,121	20,289	20,382	21,197	21,473	21,752	22,035	22,321
Accounts Receivable - Unbilled Revenue	26,641	26,405	26,748	27,818	28,179	28,546	28,917	29,293
Payments in Lieu of Income Tax Receivable	1,410	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Lease Receivable	2	2	2	1	-	-	-	
Due from Related Parties	115	1,035	2,235	3,435	4,635	5,835	7,035	8,235
Due from Windsor Utilities Commission	3,145	3,395	3,600	3,600	3,600	3,600	3,600	3,600
Inventories	4,097	4,008	3,700	3,700	3,700	3,700	3,700	3,700
Prepaid Expenses	1,767	1,317	1,300	1,300	1,300	1,300	1,300	1,300
Total Current Assets	83,503	90,802	87,242	82,531	77,015	74,095	71,786	70,747
Property, Plant and Equipment								
Property, Plant and Equipment	314,864	330,084	356,368	378,995	398,385	416,983	436,569	455,400
Accumulated Depreciation	(80,675)	(92,044)	(103,838)	(115,396)	(127,201)	(139,182)	(151,829)	(165,189
Customer Contributions	(7,700)	(7,577)	(7,330)	(7,083)	(6,836)	(6,590)	(6,343)	(6,096
Assets under Construction	3,011	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Total Property, Plant and Equipment	229,499	234,463	249,200	260,516	268,348	275,211	282,397	288,115
Other Assets								
Net Investment in Lease	8	5	2	-	-	-	-	
Investments	6,530	-	-	-	-	-	-	
Work in Progress	330	500	500	500	500	500	500	500
Receivable from WUC	2,877	2,055	1,233	411	-	-	-	
Future Payments in Lieu of Tax	10,746	10,746	10,746	10,746	10,746	10,746	10,746	10,746
Total Other Assets	20,491	13,306	12,481	11,657	11,246	11,246	11,246	11,246
TOTAL ASSETS	$333,493	$ 338,571	$348,923	$354,704	$ 356,608	$ 360,552	$ 365,429	$ 370,108
Liabilities and Equity								
Current Liabilities								
Accounts Payable and Accrued Liabilities	$ 30,429	$ 30,226	$ 31,037	$ 31,658	$ 32,290	$ 32,938	$ 33,596	$ 34,268
Due to Related Companies	-	50	50	50	50	50	50	50
Due to Windsor Canada Utilities	6,873	-	-	-	-	-	-	-
Due to City of Windsor	5,219	5,300	5,300	5,300	5,300	5,300	5,300	5,300
Customer Deposits, current portion	1,211	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Deferred Revenue	2,172	7,657	7,000	2,000	-	-	-	-
Total Current Liabilities	45,904	44,433	44,587	40,208	38,840	39,488	40,146	40,818
Long-Term Liabilities								
Customer Deposits, long-term portion	7,434	7,000	7,000	7,000	7,000	7,000	7,000	7,000
Long-Term Debt	50,457	50,463	50,483	50,497	50,511	50,526	50,542	50,558
Regulatory Liabilities	30,180	25,792	25,272	24,642	19,911	15,180	10,449	5,719
Deferred Revenue Customer Contributions	12,681	13,717	18,191	20,931	21,185	21,431	21,668	21,897
Employee Future Benefits	68,392	70,043	71,543	73,043	74,543	76,043	77,543	79,043
Total Long-Term Liabilities	169,144	167,015	172,489	176,113	173,150	170,180	167,202	164,217
Equity								
Common Shares	62,008	62,008	62,008	62,008	62,008	62,008	62,008	62,008
Contributed Capital	516	516	516	516	516	516	516	516
Retained Earnings	55,921	64,599	69,323	75,859	82,094	88,360	95,557	102,549
Total Equity	118,445	127,123	131,847	138,383	144,618	150,884	158,081	165,073
TOTAL LIABILITIES AND EQUITY	$333,493	$ 338,571	$348,923	$354,704	$ 356,608	$ 360,552	$ 365,429	$ 370,108

FINANCIAL STATEMENTS (continued)

Appendix A

ENWIN Utilities Ltd.
2019-2020 Income Statement Budget
For the period ending December 31st
(In thousands of Canadian dollars)

	2017 Actual*	2018 Forecast	2019 Budget	2020 Budget	2021 Projection	2022 Projection	2023 Projection	2024 Projection
NET DISTRIBUTION REVENUE								
Residential Distribution	$ 24,812	$ 25,674	$ 25,829	$ 25,198	$ 25,544	$ 25,895	$ 26,999	$ 27,359
General Service - Small Distribution	19,659	20,384	20,805	19,458	19,730	20,006	21,033	21,315
General Service - Large Distribution	4,712	4,950	4,991	5,066	5,132	5,199	5,266	5,335
Street Lighting - Distribution	1,715	1,790	1,757	1,865	1,889	1,913	1,938	1,964
TOTAL NET DISTRIBUTION REVENUE	$ 50,898	$ 52,798	$ 53,382	$ 51,587	$ 52,294	$ 53,013	$ 55,236	$ 55,973
% change YoY		3.7%	1.1%	-3.4%	1.4%	1.4%	4.2%	1.3%
MISCELLANEOUS REVENUES	12	(407)	(354)	2,590	2,643	2,677	2,713	2,747
% change YoY		-3491.7%	-13.0%	-831.6%	2.0%	1.3%	1.3%	1.3%
SERVICES REVENUE								
Services Provided to WUC	19,336	20,455	20,178	19,735	19,770	20,257	20,749	21,361
Services Provided to EWE	168	211	148	128	125	120	123	127
Services Provided to City of Windsor	2,891	3,120	2,828	2,611	2,708	2,759	2,837	2,915
TOTAL SERVICES REVENUE	22,395	23,786	23,154	22,474	22,603	23,136	23,709	24,403
Non-Utility MSA Contra	(19,578)	(20,965)	(20,838)	(20,604)	(20,932)	(21,533)	(22,050)	(22,606)
Depreciaton - MSA	(2,093)	(2,142)	(1,656)	(1,237)	(1,049)	(985)	(1,051)	(1,204)
TOTAL NET SERVICES REVENUE	724	679	660	633	622	618	608	593
TOTAL REVENUES	51,634	53,070	53,688	54,810	55,559	56,308	58,557	59,313
OPERATING EXPENSES								
Distribution Operation and Maintenance	8,970	10,025	10,942	10,904	11,049	11,068	11,102	11,096
Billing and Collection	2,472	2,830	3,049	3,123	3,145	3,188	3,268	3,326
Community Relations	205	244	241	218	220	224	229	234
Administration and General	3,251	3,219	3,534	3,164	3,241	3,291	3,364	3,415
Vehicles Operations and Maintenance	651	732	-	-	-	-	-	-
Property and Tools Maintenance	1,994	1,966	2,031	2,181	1,982	2,020	2,056	2,093
Salaries and Benefits	6,718	6,667	6,332	6,395	6,457	6,597	6,748	6,889
Regulatory	451	476	639	476	485	494	504	514
Employee Future Benefits	2,893	2,942	3,001	3,061	3,122	3,184	3,248	3,313
TOTAL OPERATING EXPENSES	27,605	29,101	29,769	29,522	29,701	30,066	30,519	30,880
% change YoY		5.4%	2.3%	-0.8%	0.6%	1.2%	1.5%	1.2%
OPERATING INCOME/EBITDA	24,029	23,969	23,919	25,288	25,858	26,242	28,038	28,433
% change YoY		-0.2%	-0.2%	5.7%	2.3%	1.5%	6.8%	1.4%
OTHER EXPENSES								
Depreciation	11,153	11,318	11,124	10,800	10,999	11,157	11,804	12,498
Interest Revenue	(457)	(808)	(473)	(512)	(330)	(148)	(187)	(225)
Interest Expense	2,418	2,534	2,153	2,154	2,154	2,156	2,157	2,158
Loss (Gain) on Sale of Property, Plant & Equipment	(64)	(2)	-	(576)	-	-	-	-
Settlement of Regulatory Assets/Liabilities	(1)	-	-	-	-	-	-	-
TOTAL OTHER EXPENSES	13,049	13,042	12,804	11,866	12,823	13,165	13,774	14,431
% change YoY		-0.1%	-1.8%	-7.3%	8.1%	2.7%	4.6%	4.8%
NET INCOME BEFORE TAXES - MIFRS	$ 10,980	$ 10,927	$ 11,115	$ 13,422	$ 13,035	$ 13,077	$ 14,264	$ 14,002
% change YoY		-0.5%	1.7%	20.8%	-2.9%	0.3%	9.1%	-1.8%
Current Income Taxes	3,740	(1,751)	2,390	2,886	2,803	2,812	3,067	3,011
NET INCOME - MIFRS	$ 7,240	$ 12,678	$ 8,725	$ 10,536	$ 10,232	$ 10,265	$ 11,197	$ 10,991
% change YoY		75.1%	-31.2%	20.8%	-2.9%	0.3%	9.1%	-1.8%

* *restated to conform to the current year presentation*

FINANCIAL STATEMENTS (continued)

Appendix A

ENWIN Utilities Ltd.
2019-2020 Cash Flow Budget
For the period ending December 31st
(In thousands of Canadian dollars)

	2017 Actual	2018 Forecast	2019 Budget	2020 Budget	2021 Projection	2022 Projection	2023 Projection	2024 Projection
Cash Provided by (Used in):								
OPERATING ACTIVITIES								
Net Income - MIFRS	$ 7,240	$12,678	$ 8,725	$10,536	$ 10,232	$ 10,265	$ 11,198	$ 10,991
Depreciation	13,563	11,318	11,548	11,312	11,558	11,734	12,400	13,113
Deferred Revenue Depreciation	(317)	(176)	(424)	(512)	(559)	(577)	(597)	(616)
Remeasurement of Post Employment Benefits (OCI)	5,758		-	-				
Change in Post Employment Retirement Benefits	3,159	1,651	1,500	1,500	1,500	1,500	1,500	1,500
Receivable from WUC	822	822	822	822	411	-	-	-
Cost of Issuing Long-Term Indebtedness	12	6	20	14	14	15	16	16
(Gain)/Loss on Sale of Capital Assets	(73)	(2)	-	576	-	-	-	-
Change in Deposits	1,172	(445)	-	-	-	-	-	-
Deferred Revenue - CDM	(1,384)	5,485	(657)	(5,000)	(2,000)	-	-	-
Future Payments in Lieu of Taxes	(1,087)	-	-	-	-	-	-	-
Change in Work in Process	96	(170)	-	-	-	-	-	-
Change in Regulatory Assets	992	(4,389)	(519)	(630)	(4,731)	(4,731)	(4,731)	(4,731)
Change in Non-Cash Working Capital Components	(629)	(169)	(707)	(2,465)	(1,201)	(1,198)	(1,196)	(1,188)
	29,324	26,609	20,308	16,153	15,224	17,008	18,590	19,085
FINANCING ACTIVITIES								
Dividends Paid	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)
	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)
INVESTING ACTIVITIES								
Acquisition of Capital Assets, Net	(15,589)	(16,423)	(26,284)	(23,203)	(19,390)	(18,598)	(19,586)	(18,831)
Acquisition of Investments	(1,200)	(1,200)	-	-	-	-	-	-
(Gain)/Loss on Investment	(197)	(155)	-	-	-	-	-	-
Deferred Revenue - Customer Contributions	2,189	1,213	4,898	3,252	813	823	834	844
Decrease (Increase) in Net Investment in Lease	3	3	3	3	1	-	-	-
Net Proceeds on Sale of Capital Assets	531	145	-	-	-	-	-	-
	(14,263)	(16,417)	(21,383)	(19,948)	(18,576)	(17,775)	(18,752)	(17,987)
Net Increase (Decrease) in Cash for the Period	11,061	6,192	(5,075)	(7,795)	(7,352)	(4,767)	(4,162)	(2,902)
Cash (Bank Indebtedness), Beginning of Period	15,144	26,205	32,397	27,322	19,527	12,175	7,408	3,246
Cash (Bank Indebtedness), End of Period	$26,205	$32,397	$27,322	$19,527	$ 12,175	$ 7,408	$ 3,246	$ 344

2019 BUDGET VARIANCE ANALYSIS

Appendix B

ENWIN Utilities Ltd.
Variance Analysis
2019 Budget vs. 2018 Forecast
(In thousands of Canadian dollars)

NET DISTRIBUTION REVENUE	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Residential Distribution	$ 25,829	$ 25,674	$ 155	0.6%	Projected 0.6% increase in distribution rates, same as 2018 IRM.
General Service - Small Distribution	20,805	20,384	421	2.1%	Projected 0.6% increase in distribution rates, same as 2018 IRM, with a 2.3% increase in consumption (kW).
General Service - Large Distribution	4,991	4,950	41	0.8%	Projected 0.6% increase in distribution rates, same as 2018 IRM, with a 3.2% increase in consumption (kW).
Street Lighting - Distribution	1,757	1,790	(33)	(1.8%)	Projected 0.6% increase in distribution rates, same as 2018 IRM with adjustments based on most recent number of connections.
Total Net Distribution Revenue	***$ 53,382***	***$ 52,798***	**$ 584**	**1.1%**	Update to revenue forecast completed. Forecast is based on the same approved rate increase as the 2018 IRM with adjustments for most recent customer counts/connections and consumption.

SERVICES REVENUE	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Service Provided to WUC	$ 20,178	$ 20,455	(277)	(1.4%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Services Provided to EWE	148	211	(63)	(29.9%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Services Provided to City	2,828	3,120	(292)	(9.4%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Non-Utility MSA Contra	(20,838)	(20,965)	127	(0.6%)	Lower charged service costs anticipated.
Depreciaton - MSA	(1,656)	(2,142)	486	(22.7%)	Reduction is due to a significant asset becoming fully depreciated in 2018.
Total Net Services Revenue	***$ 660***	***$ 679***	**$ (19)**	**(2.8%)**	Consistent with 2018 forecast.

MISCELLANEOUS REVENUE	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Change of Occupancy	$ 376	$ 352	24	6.8%	Increase is mainly due to revenue from change occupancy charges budgeted at historical rates (2018 forecast is lower than average).
Late Payment and Collection Charges	384	392	(8)	(2.0%)	Consistent with 2018 forecast.
Pole Rental	744	689	55	8.0%	Increased number of 3rd party pole attachments with existing customers required for fibre network.
Sale of Scrap	100	113	(13)	(11.5%)	Decrease is mainly due to scrap revenue budgeted at historical rates (2018 forecast is higher than average).
Other Operating Revenue	(1,958)	(1,953)	(5)	0.3%	Consistent with 2018 forecast. The overall debit in both years is a result of the IFRS/GAAP regulated liability being realized in both 2018 and 2019.
Total Miscellaneous Revenues	***$ (354)***	***$ (407)***	***$ 53***	***(13.0%)***	
TOTAL REVENUES	***$ 53,688***	***$ 53,070***	**$ 618**	**1.2%**	

2019 BUDGET VARIANCE ANALYSIS (continued) Appendix B

ENWIN Utilities Ltd.
Variance Analysis
2019 Budget vs. 2018 Forecast
(In thousands of Canadian dollars)

Operating Expenses	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Distribution Operation and Maintenance	$ 10,942	$ 10,025	(917)	(9.1%)	Increased costs are mainly due to the reclassification of costs from Vehicle Operations and Maintenance.
Billing and Collection	3,049	2,830	(219)	(7.7%)	Increase is mainly due to bad debts being budgeted at historical levels (2018 is lower than average).
Community Relations	241	244	3	1.2%	Consistent with 2018 forecast.
Administration and General	3,534	3,219	(315)	(9.8%)	Increase is mainly resulting from the Cost of Service deferral to 2020, resulting in some expenses originally planned for 2018 being delayed to 2019.
Vehicle Operations and Maintenance	-	732	732	100.0%	2019 expenses have been reclassified throughout the income statement (mainly to Distribution Operation and Maintenance).
Property and Tools Maintenance	2,031	1,966	(65)	(3.3%)	Increase is mainly due to increased costs for tool maintenance due to robust tool calibration programs and planned purchases of replacement tools.
Salaries and Benefits	6,332	6,667	335	5.0%	Decreased costs are mainly due to lower headcount.
Regulatory	639	476	(163)	(34.2%)	2019 budgeted costs include additional costs related to the Cost of Service application.
Employee Future Benefits	3,001	2,942	(59)	(2.0%)	Projected 2% increase in Employee Future Benefits cost.
Total Operating Expenses	***$ 29,769***	***$ 29,101***	***$ (668)***	***(2.3%)***	

Operating Income/EBITDA	***$ 23,919***	***$ 23,969***	***$ (50)***	***(0.2%)***	

Other Expenses	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Depreciation	$ 11,124	$ 11,318	194	1.7%	Reduction is due to a significant technology asset becoming fully depreciated in 2018, despite a projected higher level of capital spending.
Interest Revenue	(473)	(808)	(335)	41.5%	Reduction is due to elimination on interest revenue on sinking fund investment as a result of transferring this investment to Windsor Canada Utilities Ltd.
Interest Expense	2,153	2,534	381	15.0%	Reduction is due to lower interest charges on intercompany loan payable to Windsor Canada Utilities Ltd. as a result of transferring the sinking fund investment.
Loss (Gain) on Sale of Property, Plant & Equipment	-	(2)	(2)	100.0%	Consistent with 2018 forecast.
Total Other Expenses	***$ 12,804***	***$ 13,042***	***$ 237***	***1.8%***	

	2019 Budget	2018 Forecast	Positive (Negative) Variance	% Variance	Reasons for Variance
Net Income Before Taxes - MIFRS	***$ 11,115***	***$ 10,927***	***$ 188***	***1.7%***	

Current Income Taxes	2,390	(1,751)	(4,141)	236.5%	Due to changes in the tax deductibility of capitalized costs, a significant tax credit is expected in 2018. Rate is consistent at 21.5%.
Net Income - MIFRS	***$ 8,725***	***$ 12,678***	***$ (3,953)***	***(31.2%)***	

2020 BUDGET VARIANCE ANALYSIS

Appendix B

ENWIN Utilities Ltd.
Variance Analysis
2020 Budget vs. 2019 Budget
(In thousands of Canadian dollars)

NET DISTRIBUTION REVENUE	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Residential Distribution	$ 25,198	$ 25,829	$ (631)	(2.4%)	Projected 5.76% increase in distribution rates based on COS revenue requirement calculations, with adjustments for rate rider refunds to customers resulting from IFRS and HST transitions.
General Service - Small Distribution	19,458	20,805	(1,347)	(6.5%)	Projected 5.76%% increase in distribution rates based on COS revenue requirement calculations, with adjustments for rate rider refunds to customers resulting from IFRS and HST transitions and expiration of the LRAM rate rider.
General Service - Large Distribution	5,066	4,991	75	1.5%	Projected 5.76% increase in distribution rates based on COS revenue requirement calculation, with adjustments to rate riders.
Street Lighting - Distribution	1,865	1,757	108	6.1%	Projected 5.76% increase in distribution rates based on COS revenue requirement calculation, with adjustments to rate riders.
Total Net Distribution Revenue	***$ 51,587***	***$ 53,382***	**$ (1,795)**	**(3.4%)**	Projected 5.76% increase in distribution rates based on COS revenue requirement calculations, offset by adjustments for rate rider refunds to customers mainly resulting from IFRS and HST transitions and expiration of the LRAM rate riders.

SERVICES REVENUE	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Service Provided to WUC	$ 19,735	$ 20,178	(443)	(2.2%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Services Provided to EWE	128	148	(20)	(13.5%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Services Provided to City	2,611	2,828	(217)	(7.7%)	Services provided to WUC and allocated through OEB-reviewed shared services model. Consistent with 2018 forecast with reduced charges for shared operating and capital expenditures.
Non-Utility MSA Contra	(20,604)	(20,838)	234	(1.1%)	Lower shared service cost anticipated.
Depreciaton - MSA	(1,237)	(1,656)	419	(25.3%)	Reduction is due to a significant asset becoming fully depreciated in 2019.
Total Net Services Revenue	***$ 633***	***$ 660***	**$ (27)**	**(4.1%)**	Consistent with 2019 budget.

MISCELLANEOUS REVENUE	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Change of Occupancy	$ 376	$ 376	-	0.0%	Consistent with 2019 budget.
Late Payment and Collection Charges	384	384	-	0.0%	Consistent with 2019 budget.
Pole Rental	1,470	744	726	97.6%	Increase due to the OEB approving increased rates for 3rd party wireline pole attachments.
Sale of Scrap	100	100	-	0.0%	Consistent with 2019 budget.
Other Operating Revenue	260	(1,958)	2,218	(113.3%)	Increase is due to the elimination of the regulatory PP&E adjustment as a result of COS.
Total Miscellaneous Revenues	***$ 2,590***	***$ (354)***	***$ 2,944***	***(831.6%)***	
TOTAL REVENUES	***$ 54,810***	***$ 53,688***	**$ 1,122**	**2.1%**	Consistent with 2019 budget.

2020 BUDGET VARIANCE ANALYSIS (continued)

Appendix B

ENWIN Utilities Ltd.
Variance Analysis
2020 Budget vs. 2019 Budget
(in thousands of Canadian dollars)

Operating Expenses	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Distribution Operation and Maintenance	$ 10,904	$ 10,942	38	0.3%	Consistent with 2019 budget.
Billing and Collection	3,123	3,049	(74)	(2.4%)	Projected 2% increase based on CPI.
Community Relations	218	241	23	9.5%	Reduction is due to completion of Enwin's contribution to support St. Clair College's National Powerline Training Centre initiative.
Administration and General	3,164	3,534	370	10.5%	Reduction is mainly resulting from Cost of Service legal costs budgeted in 2019.,
Property and Tools Maintenance	2,181	2,031	(150)	(7.4%)	Increase is mainly due to moving costs related to the building consolidation.
Salaries and Benefits	6,395	6,332	(63)	(1.0%)	Projected inflationary increases in wages and benefits partially offset by headcount reduction.
Regulatory	476	639	163	25.5%	2019 budgeted costs include additional costs related to the Cost of Service application.
Employee Future Benefits	3,061	3,001	(60)	(2.0%)	Projected 2% increase in Employee Future Benefits cost.
Total Operating Expenses	***$ 29,522***	***$ 29,769***	***$ 247***	***0.8%***	

Operating Income/EBITDA	***$ 25,288***	***$ 23,919***	***$ 1,369***	***5.7%***	

Other Expenses	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Depreciation	$ 10,800	$ 11,124	324	2.9%	Reduction is due to a significant technology asset becoming fully depreciated in 2019.
Interest Revenue	(512)	(473)	39	(8.2%)	Increase is due to higher interest charges on increasing intercompany amount receivable from Windsor Canada Utilities Ltd.
Interest Expense	2,154	2,153	(1)	(0.0%)	Consistent with 2019 budget.
Loss (Gain) on Sale of Property, Plant & Equipment	(576)	-	576	100.0%	Projected gain on sale of property due to building consolidation.
Total Other Expenses	***$ 11,866***	***$ 12,804***	***$ 937***	**7.3%**	

	2020 Budget	2019 Budget	Positive (Negative) Variance	% Variance	Reasons for Variance
Net Income Before Taxes - MIFRS	***$ 13,422***	***$ 11,115***	***$ 2,307***	**20.8%**	
Current Income Taxes	2,886	2,390	(496)	(20.8%)	Rate is consistent at 21.5%.
Net Income - MIFRS	***$ 10,536***	***$ 8,725***	***$ 1,811***	**20.8%**	

CAPITAL BUDGET – Summary

Appendix C

ENWIN Utilities Ltd.
6 Yr Capital Plan Summary Review 2019-2024
(in 000's)

ENWIN Utilities Ltd.	Ref #	Actuals 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget 2024
System Access		1,783	1,733	2,878	3,113	2,663	2,703	2,743	2,784
System Renewal		5,897	5,275	6,780	7,921	8,009	7,605	7,850	7,366
System Service		4,324	4,427	4,221	3,896	3,622	3,610	3,986	3,623
General Plant		2,058	2,265	4,855	3,417	2,980	2,548	2,514	2,684
OEB Category Capital Expenditures		14,061	13,699	18,734	18,346	17,274	16,465	17,093	16,456
Vehicles		-	834	2,652	1,605	1,303	1,309	1,660	1,530
Total ENWIN Utilities Ltd. Capital Expenditures		14,061	14,533	21,386	19,951	18,577	17,774	18,753	17,986

CAPITAL BUDGET – Detail

Appendix C

ENWIN Utilities Ltd.
6 Yr Capital Plan Summary Review 2019-2024
(in 000's)

ENWIN Utilities Ltd.	Ref #	Actuals 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget 2024
System Access									
New Customer Connections									
Bridge Plaza new services		-	50	-	-	-	-	-	-
O/H Customer Connections	1	464	515	525	536	546	557	568	580
U/G Customer Connections	1	1,269	1,100	750	525	1,301	1,327	1,354	1,381
		1,733	1,665	1,275	1,061	1,847	1,884	1,922	1,960
Externally Driven Projects									
Bridge Plaza Relocation	2	1,050	500	1,700	1,000	-	-	-	-
Bridge Duct Extension		-	-	-	-	-	-	-	-
Broadway/Ojibway (WMEG)		-	7	-	-	-	-	-	-
Ambassador Bridge Twin Span	2	-	16	2,000	1,000	-	-	-	-
Road Widening Projects (City Driven Specifics)	2	213	585	226	1,094	1,200	1,200	1,200	1,200
Walker Rd	2	-	-	750	-	-	-	-	-
Cabana Road - Dougall to Dominion	2	-	-	910	-	-	-	-	-
Riverside Vista Project (City Driven Specifics)	2	386	67	-	1,156	-	-	-	-
		1,649	1,175	5,586	4,250	1,200	1,200	1,200	1,200
Metering New Services									
Meter work - new customers (enhancement)	3	581	470	406	417	429	442	455	468
Meter Population Replacement / Upgrade (MIST Meters)	4	23	250	509	519	-	-	-	-
MIST Meter Equipment		13	61	-	-	-	-	-	-
		617	781	915	936	429	442	455	468
Customer Contributions									
CC Road Widening Projects (City Driven Specifics)	2	(82)	(50)	(50)	(260)	(300)	(300)	(300)	(300)
CC Walker Rd	2	-	-	(300)	-	-	-	-	-
CC Cabana Road - Dougall to Dominion	2	-	-	(355)	-	-	-	-	-
CC Riverside Vista Project (City Driven Specifics)		-	(159)	-	(371)	-	-	-	-
CC O/H Customer Connections	1	(246)	(160)	(163)	(166)	(170)	(173)	(176)	(180)
CC U/G Customer Connections	1	(486)	(1,000)	(330)	(337)	(343)	(350)	(357)	(364)
CC Meter work		(13)	-	-	-	-	-	-	-
CC Rt. Hon. Herb Gray Parkway		(12)	-	-	-	-	-	-	-
Rt. Hon. Herb Gray Parkway (relocate Huron Line, Ojib, Match, Malden)		-	-	-	-	-	-	-	-
CC Ambassador Twin Span	2	-	(20)	(2,000)	(1,000)	-	-	-	-
CC Bridge Plaza Relocation	2	(1,378)	(500)	(1,700)	(1,000)	-	-	-	-
		(2,217)	(1,889)	(4,898)	(3,134)	(813)	(823)	(834)	(844)
System Access		1,783	1,733	2,878	3,113	2,663	2,703	2,743	2,784
System Renewal									
Sustainment Programs									
Reactive Replacement of Failed Equipment (U/G, O/H)	5	69	55	180	180	180	180	180	180
Reactive Replacement of Failed Cable	5	207	30	90	90	90	90	90	90
Reactive Replacement of Transformers	5	370	275	250	250	250	250	250	250
Reactive Pole Replacement	5	343	150	50	50	50	50	50	50
Reactive Pole Pulling	5	-	-	50	50	50	50	50	50
Reactive Hardware Replacement Program	5	-	57	100	100	100	100	100	100
Reactive Manhole/Vault Rehabilitation	5	-	10	20	20	20	20	20	20
Pole Inspection		-	-	-	-	-	-	-	-
Pole Sustaining Program	6	2,556	2,200	2,950	3,300	3,300	3,300	3,300	3,300
UG PadMount Sustaining Program	7	414	500	280	255	277	297	256	256
Submersible Sustainment Program	8	225	360	690	690	690	690	690	690
O/H 3-Phase Transformer Sustainment	9	192	130	130	130	130	130	130	130
Manhole Rebuild Program	10	109	160	150	150	150	150	150	150
Switching Unit Sustaining Program	11	296	260	300	300	300	300	300	300
Removal of PMH-4 & PMH-Specials		-	-	25	25	25	25	25	25
Vacuum Switch Replacements	12	-	-	-	200	-	-	-	-
CPP Switch Controller Replacements	13	-	-	100	100	100	100	100	100
Underground Cable Sustainment (Feeder)		-	6	17	-	-	-	-	-
Underground Cable Sustainment (Sub Division)	14	46	209	103	512	1,500	841	394	-
Recloser Sustaining Program		142	4	-	-	-	-	-	-
Insulator Replacement Program (427 poles)	15	162	150	200	-	-	-	-	-
Customer SU Vault Sustainment	16	-	-	400	400	-	-	-	-
Switch Animal Protection		-	80	-	-	-	-	-	-
4kv Conversion		-	-	-	-	-	-	-	-
Walker Road-Foster to Airport Rd	17	-	-	-	750	-	-	-	-
		5,130	4,635	6,085	7,552	7,212	6,573	6,085	5,691

CAPITAL BUDGET – Detail (continued)

Appendix C

ENWIN Utilities Ltd.
6 Yr Capital Plan Summary Review 2019-2024
(in 000's)

ENWIN Utilities Ltd.	Ref #	Actuals 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget 2024
Metering Sustainment									
Meter work - end of life (sustainment)		31	65	34	35	36	36	37	38
Retest Smart Meters	18	-	60	125	146	221	453	183	62
Meter Tank Replacement	19	-	87	111	113	115	118	120	-
		31	212	270	294	372	607	340	100
S.A.M Station Sustainment									
Replacement of NSD 70 - MTS	20	-	-	350	-	350	350	350	-
Replacement of NSD 70 with NSD 570 TT Equipment		0	-	-	-	-	-	-	-
Walker TS Disconnect Switch Replacement		-	-	-	-	-	-	-	-
Walker TS Feeder - 27.6 Tie		-	-	-	-	-	-	-	-
GM MTS Conversion to Distribution TS		-	-	-	-	-	-	-	-
PLC /Relay EOL Equipment Replacement		160	-	-	-	-	-	-	-
GM: PLC /Relay EOL Equipment Replacement		-	350	-	-	-	-	-	-
Miscellaneous TS Equipment, EOL Replacement	21	73	75	75	75	75	75	75	75
Miscellaneurs TS assets		-	-	-	-	-	-	1,000	1,500
Walker 2 TS-Units 2- New Gasket & Oil Program		504	3	-	-	-	-	-	-
		736	428	425	75	425	425	1,425	1,575
System Renewal		**5,897**	**5,275**	**6,780**	**7,921**	**8,009**	**7,605**	**7,850**	**7,366**
System Service									
Enhancement Projects									
Conductor Upgrade	17	266	767	712	200	849	407	451	-
55M3 Conductor Upgrade		506	- 26	-	-	-	-	-	-
25M7 Feeder Ring Project	22	-	-	-	380	-	-	-	-
55M25 3 phase extension(Howard Ave)		-	-	-	-	-	-	-	-
15M10 Extension down Walker - Underground		-	-	-	-	-	-	-	-
55M24 Northwood Street Connection		-	-	-	-	-	-	-	-
Sectionalizing Load Break Switches	23	520	595	504	144	-	-	-	-
Automated Switches		571	3	-	-	-	-	-	-
Underground Switching Units	24	-	700	550	550	550	550	550	550
Feeder Reliability Improvement Project	25	940	1,600	1,250	1,224	1,363	783	915	-
Overloaded Transformer Replacement		4	-	-	-	-	-	-	-
GM MTS Feeders		-	-	-	-	-	-	-	-
WFCU Feeder Backup		-	-	-	-	-	-	-	-
Feeder Tie	26	81	90	105	119	140	-	-	-
Feeder Balancing		-	-	50	50	50	50	50	50
Cousineau Road U/G Relocation		195	2	-	-	-	-	-	-
56M6 Jefferson Connection (Green Energy Enable)		1	-	-	-	-	-	-	-
Transformer Metering		53	-	-	-	-	-	-	3
Radial Branch Backups (College & Felix)	27	509	356	400	400	400	400	400	400
Engineering Power Quality		-	0	5	5	5	5	5	5
Wholesale Metering: Keith TS Feeders	28	-	-	-	477	-	-	-	-
CC Wholesale Metering: Keith TS Feeders	28	-	-	-	(118)	-	-	-	-
		3,644	4,087	3,576	3,431	3,357	2,195	2,371	1,008
SCADA									
SCADA FCI's	29	285	200	250	70	70	70	70	70
SCADA Misc Sustaining		52	40	45	45	45	45	45	45
SCADA communications evolution design	30	77	-	150	-	-	-	-	-
SCADA communications Equipment	30	22	-	150	150	150	-	-	-
SCADA EOL GUI Replacement - SmartView		-	-	-	-	-	-	-	-
Hanna Tower to Cook Station - High Speed Radio Link		-	-	-	-	-	-	-	-
		436	240	595	265	265	115	115	115
S.A.M Station Enhancements									
Redundant Station Battery Banks	31	50	100	50	-	-	-	-	-
Green Energy Plan / Walker 2 Reactors	32	-	-	-	200	-	1,300	1,500	2,500
Motion Detection for MTS Sites/ Security Enhancements		8	-	-	-	-	-	-	-
Protection Coordination Study - MTS		186	-	-	-	-	-	-	-
		243	100	50	200	-	1,300	1,500	2,500
System Service		**4,324**	**4,427**	**4,221**	**3,896**	**3,622**	**3,610**	**3,986**	**3,623**

CAPITAL BUDGET – Detail (continued)

Appendix C

ENWIN Utilities Ltd.
6 Yr Capital Plan Summary Review 2019-2024
(in 000's)

ENWIN Utilities Ltd.	Ref #	Actuals 2017	Forecast 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget 2024
General Plant									
Tools									
Operations		229	90	93	92	101	101	101	91
Engineering		-	-	5	5	5	5	5	5
Meter Shop		2	-	89	5	5	5	5	5
		231	90	187	102	111	111	111	101
Building and Equipment									
Leasehold Improvements for Alton C. Parker Building	33	-	-	150	-	-	-	-	-
Remediation of Substations		108	30	-	-	-	-	-	-
Scada Distribution Management System		-	-	-	-	750	250	200	200
Site Rhodes	34	205	304	2,442	1,521	507	500	501	496
Site Ouellette		39	20	-	-	-	-	-	-
Weld Shop / Meter Shop / Stores / Garage		87	88	71	75	75	75	75	75
		439	442	2,663	1,596	1,332	824	775	770
Information Technology									
Life Cycle Upgrades	35	326	458	452	503	423	803	478	478
Telephone System Upgrade		-	-	-	-	-	-	-	100
GIS Evolution and Integration	36	152	195	190	210	355	210	450	355
SAP Evolution	37	118	275	100	100	160	250	350	280
Network Infrastructure Update and Cyber Security	38	167	100	100	100	50	50	50	100
Customer Relationship, Billing and IVR	39	125	255	315	240	200	200	200	400
NorthStar Evolution	40	-	-	324	-	-	-	-	-
Records Management System	41	-	-	345	332	-	-	-	-
Strategic Enhancements and Tools	42	-	300	180	235	350	100	100	100
SAP HANA/Integration		499	150	-	-	-	-	-	-
EnSight GIS (Including CYME)		-	-	-	-	-	-	-	-
		1,387	1,733	2,005	1,719	1,538	1,613	1,628	1,813
General Plant		2,058	2,265	4,855	3,417	2,980	2,548	2,514	2,684
OEB Category Capital Expenditures		14,061	13,699	18,734	18,346	17,274	16,465	17,093	16,456
Vehicles									
Hydro Operations	43	-	739	2,556	1,281	1,165	1,309	1,660	1,500
Hydro Metering	43	-	24	-	95	-	-	-	-
Hydro Control Room	43	-	-	-	-	-	-	-	-
Hydro Engineering	43	-	47	-	70	33	-	-	-
Technical Services	43	-	24	-	-	35	-	-	-
Safety	43	-	-	60	-	-	-	-	-
Site Rhodes	43	-	-	-	123	-	-	-	30
Mail Room	43	-	-	-	35	-	-	-	-
Fleet Services	43	-	-	-	-	-	-	-	-
Store Room	43	-	-	-	-	-	-	-	-
Meter Reading	43	-	-	37	-	70	-	-	-
Vehicles		-	834	2,652	1,605	1,303	1,309	1,660	1,530
Total ENWIN Utilities Ltd. Capital Expenditures		14,061	14,533	21,386	19,951	18,577	17,774	18,753	17,986

LEGAL AND CONSULTING SCHEDULE

Appendix D

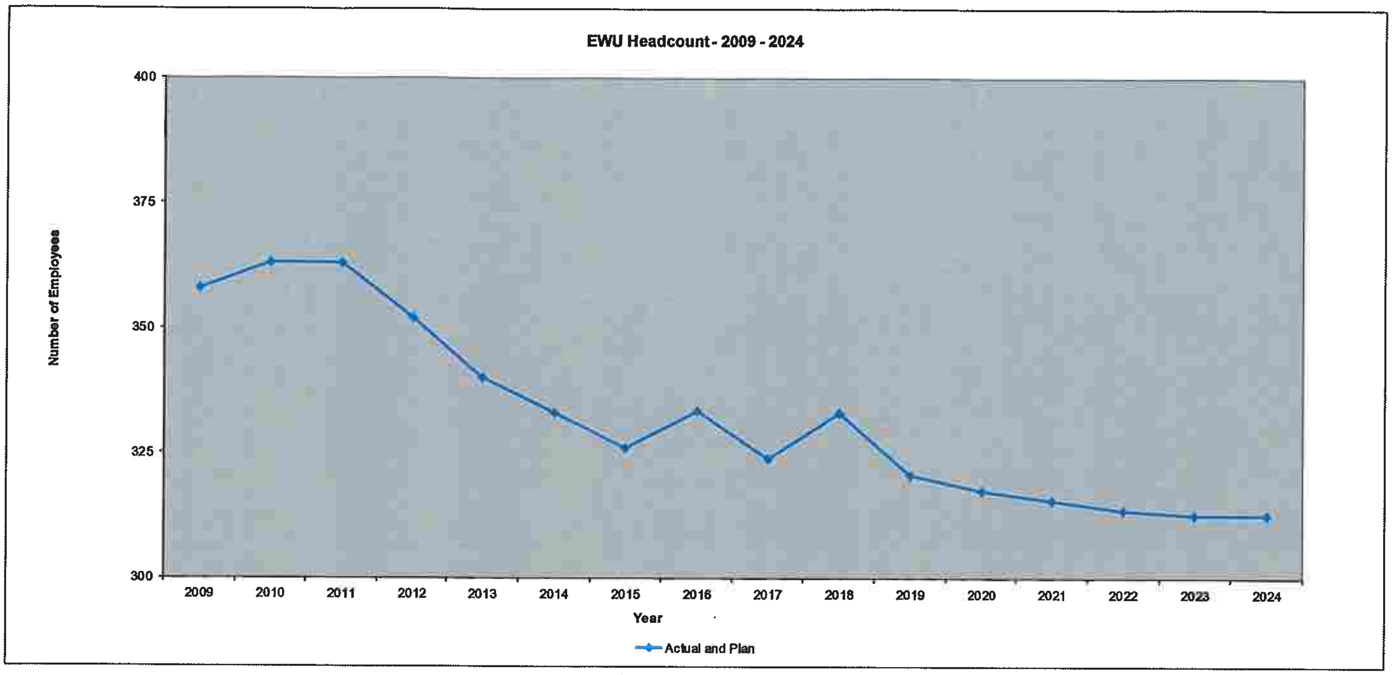
ENWIN Utilities Ltd.
Legal & Consulting Budget
2019-2020 Budget

Legal & Professional Details	2017 Actuals	2018 Forecast	2018 Budget	2019 Budget	2020 Projection	2021 Projection	2022 Projection	2023 Projection	2024 Projection
Legal Fees									
Corporate & Commercial									
Hydro Executive	-	420	-	-	-	-	-	-	-
Hydro Administration - litigation	68,953	31,586	40,000	50,000	50,000	50,000	51,000	52,020	53,060
Hydro Distribution	-	3,380	5,510	5,000	5,000	5,000	5,100	5,202	5,306
SCADA	(45)	-	-	-	-	-	-	-	-
Hydro Engineering	6,997	5,000	10,000	7,000	7,000	7,000	7,140	7,283	7,428
Technical Services	6,489	5,919	6,900	3,450	3,450	3,450	3,519	3,589	3,661
Hydro Metering	3,069	2,850	5,700	-	-	-	-	-	-
CEO Executive Office - corporate initiatives	5,085	51,506	100,000	100,000	100,000	100,000	102,000	104,040	106,121
CFO Executive Office - governance	10,805	-	-	-	-	-	-	-	-
Information Technology - contract review	25,330	32,410	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Hydro Geomatics	113	-	-	-	-	-	-	-	-
Finance	250	1,310	2,000	1,800	1,800	1,800	1,836	1,873	1,910
Purchasing	(547)	13,536	7,646	12,420	12,420	12,420	12,668	12,922	13,180
Stores	-	-	-	-	-	-	-	-	-
Customer Service	2,859	2,000	4,000	4,000	4,000	4,000	4,080	4,162	4,245
Employment / Labour	26,691	30,677	50,000	50,000	50,000	50,000	51,000	52,020	53,060
Regulatory	104,240	62,977	112,000	55,000	56,000	57,020	58,160	59,324	60,510
Cost of Service	31,168	69,992	130,000	300,000	-	-	-	-	-
MSA	(32,262)	(57,956)		(95,649)	(95,649)	(95,649)	-	-	-
Total Legal	**$ 259,195**	**$ 255,608**	**$ 513,756**	**$ 533,021**	**$ 234,021**	**$ 235,041**	**$ 336,504**	**$ 342,434**	**$ 348,483**
Professional & Consulting Fees									
Executive / Governance									
Strategic Planning / Provisional Consulting	16,885	60,000	120,000	120,000	120,000	120,000	122,400	124,848	127,345
S&P / Computershare	58,510	8,177	5,253	10,950	-	10,950	-	11,169	-
Executive/Governance Consulting	30,000	12,500	25,000	36,800	36,800	36,800	37,536	38,287	39,052
Studies & Appraisals building consolidation	-	53,050	100,000	-	-	-	-	-	-
Human Resources									
Pay Equity / Miscellaneous	18,156	6,092	12,000	12,000	32,000	12,000	12,240	12,485	12,734
EAP	14,310	14,100	17,040	17,040	17,040	17,040	17,381	17,728	18,083
WSIB Consultant	8,413	5,900	10,020	10,020	10,020	10,020	10,220	10,425	10,633
Benefits Consultant	40,200	22,450	21,500	23,500	23,500	23,500	23,970	24,449	24,938
Salary Market Review	17,301	-	-	-	-	-	-	-	-
Surveillence	-	3,000	6,000	6,000	6,000	6,000	6,120	6,242	6,367
Finance / IT / Regulatory									
Regulatory Studies	-	1,300	2,600	2,600	27,600	27,600	28,152	28,715	29,289
Cost of Service	231,309	118,800	124,000	100,000	-	-	-	-	-
Actuarial Fees	15,000	15,000	15,000	30,000	16,000	16,000	16,320	16,646	16,979
Audit Fees/Tax Consulting	51,700	84,460	104,000	90,000	92,000	92,500	94,350	96,237	98,162
Internal Audits	991	26,700	53,400	55,400	58,900	53,400	54,468	55,557	56,669
IT Consultation	155,680	248,840	346,674	372,110	263,304	244,891	249,788	254,784	259,880
Operations									
ISO/ESA Audits	7,802	28,040	2,500	5,500	29,500	5,500	5,610	5,722	5,837
Asset Management Fees	-	1,650	3,300	3,300	3,300	3,300	3,366	3,433	3,502
H&S External Audit	7,186	21,746	14,600	14,600	14,692	14,786	15,082	15,383	15,691
MSA	(165,404)	(249,272)	-	(344,898)	(301,318)	(282,180)	-	-	-
Total Professional & Consulting	**$ 508,039**	**$ 482,532**	**$ 982,887**	**$ 564,922**	**$ 449,338**	**$ 412,107**	**$ 697,003**	**$ 722,112**	**$ 725,162**

HEADCOUNT SCHEDULE

Appendix E

ENWIN Utilities
Headcount Report
Budget 2019 & 2020 Submission



	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Fcst 2018	Budget 2019	Budget 2020	Proj. 2021	Proj. 2022	Proj. 2023	Proj. 2024
Services	135	132	128	129	127	121	128	135	133	138	133	133	132	132	132	132
Water	101	101	100	95	86	82	79	70	68	68	65	61	61	61	61	61
Electricity	122	130	135	128	127	130	119	129	123	127	123	124	123	121	120	120
Total Headcount	358	363	363	352	340	333	326	334	324	333	321	318	316	314	313	313
2018 Budget	358	363	363	352	340	333	326	334	334	333	330	328	327	324	322	
Variance	0	0	0	0	0	0	0	0	10	0	9	10	11	10	9	
OEB - electricity only	194	192	193	196	198	190	190	197	198	195	195	196	195	193	192	192

ENWIN UTILITIES LTD.

BOARD OF DIRECTORS MEETING
IN CAMERA MEETING MINUTES

MONDAY, SEPTEMBER 17, 2018

ATTENDANCE:

Directors: Vic Neufeld (Chair), Drew Dilkens, Garnet Fenn (by phone), Jo-Anne Gignac, Marty Komsa and Abe Taqtaq

Management: President & CEO Helga Reidel, VP Shared Services & COO John Wladarski, VP Water Operations Garry Rossi, VP Hydro Operations Jim Brown, VP Finance & CFO Byron Thompson, Director of Finance Matt Carlini, Director of Regulatory Affairs and Corporate Secretary Paul Gleason, Director of Customer Service Rob Spagnuolo, Director of Human Resources Suzanne Leonard, Manager of Conservation Demand Management Chris Routliffe, Assistant Corporate Secretary Stephanie Wrixon, Communications Coordinator John-Paul Bonadonna and Assistant to the President and Recording Secretary Debbie Ens

Guest: Janice Guthrie, City of Windsor

CALL TO ORDER & DECLARATION OF CONFLICTS OF INTEREST

The Chair noting quorum called the in camera meeting to order at 10:04 a.m.

No conflicts of interest were declared.

CONSENT AGENDA

Moved and seconded
That the following Consent Agenda items be approved as recommended.

- EWU In Camera Board Meeting Minutes for June 26, 2018 be approved.

-CARRIED

COMMUNICATION AGENDA

COGECO / 350 ERIE STREET

A Board member inquired about the total cost of the sale transaction. The CEO explained the details of the transaction and what was still outstanding. There was discussion on what could be done differently in the future, with the CEO noting that multiple sale agreements should be avoided, that leases should be registered on title, and that legal counsel should remain continuous on a matter, to the extent possible.

TECUMSEH BULK SUPPLY RATE ADJUSTMENT
A Board member requested information on Tecumseh's water rates compared to Windsor's. The CEO advised that it can't easily be compared because of Tecumseh's separate distribution costs, but Management will report back to the Board with information. G. Rossi advised that the Corporation of the Town of Tecumseh approved the increase at the September 11, 2018 meeting of Council.

Moved and seconded
That the following Communication Agenda items be received as recommended.

- Draft EWU Executive Committee Meeting Minutes for August 24, 2018 be received.
- Draft EWU Governance & Human Resources Committee Meeting Minutes for August 23, 2018 be received.
- Draft EWU Audit & Finance Committee Meeting Minutes for September 5, 2018 be received.
- Whistleblower Hotline Second Quarter Report for the period ended June 30, 2018 be received.
- Listing of Open Legal Matters: Semi-Annual Update (Q1/Q2 2018) report be received.
- Cogeco / 350 Erie Street Update be received.
- Street Lighting Update Report be received.
- Tecumseh Bulk Supply Rate Adjustment report be received.
- Initiative Tracking Report be received.

-CARRIED

ENWIN EXECUTIVE REPORTS

EWU BUSINESS PLAN 2019 - 2024

Moved and seconded
That the EWU Business Plan 2019 – 2024 BE APPROVED. **-CARRIED**

EWU 2019 – 2024 DRAFT BUSINESS PLAN AND OPERATING AND CAPITAL BUDGETS

The CEO advised the Board that the headcount schedule included at Appendix E of the report had been amended since the report presented at the Audit & Finance Committee meeting of September 5, 2018 .

Moved and seconded
That the ENWIN Utilities Ltd. 2019 – 2024 Business Plan and Operating and Capital Budgets be approved, as recommended by the EWU Audit & Finance Committee.

And, that four quarterly dividends of $1,000,000 each, be declared and paid to Windsor Canada Utilities Ltd. for 2019, effective March 28, 2019, June 27, 2019, September 26, 2019 and December 19, 2019, as recommended by the EWU Audit & Finance committee. **-CARRIED**

REGULATORY AFFAIRS REPORT

Moved and seconded
THAT the Regulatory Affairs Report be RECEIVED for information. **-CARRIED**

WUC 2019 – 2024 DRAFT BUSINESS PLAN AND OPERATING AND CAPITAL BUDGETS

Moved and seconded
That the WUC 2019 – 2024 Business Plan and Operating and Capital Budgets be received. **-CARRIED**

CORPORATE METRICS – 2018 INTERIM REPORT AND 2019 PROPOSED

Moved and seconded
That the report of the President & CEO regarding the corporate metrics BE RECEIVED for information and that the 2019 Metrics BE APPROVED IN PRINCIPLE subject to a final report not later than April, 2019. **-CARRIED**

NON UNION INCENTIVE PROGRAM REPORT

Moved and seconded
That the Non Union Incentive Pay Plan Report BE APPROVED by the Board, as recommended by the EWU Audit and Finance Committee. **-CARRIED**

WATER AND HYDRO DIVISION COLLECTIVE AGREEMENT UPCOMING NEGOTIATIONS

The chair advised that this topic was discussed at the Governance Committee meeting. Management is to look at post-retirement benefits and benefit supplier.

Moved and seconded
That this report be received for information and that the Board provide any direction alternative to the contents of this report, to Management. **-CARRIED**

BOARD & COMMITTEE EVALUATION SUMMARY

Moved and seconded
That the Board and Committee Evaluation Summary for the ENWIN Utilities Ltd. report BE RECEIVED for information. **-CARRIED**

OTHER BUSINESS

None noted.

MOTION TO TERMINATE IN CAMERA SESSION

Moved and seconded
That the In Camera session be terminated. **-CARRIED**

The In Camera session terminated at 10:28 a.m.

Chair

Recording Secretary

1 - AMPCO - 3

Reference:

Exhibit 1: Administration

Question:

Please update Chapter 2 Appendices with 2018 actuals and 2019 forecast.

Response:

Chapter 2 Appendices have been updated with 2018 actuals. The 2019 forecast remains as filed on April 26, 2019.

Please note that due to restrictions in the model, ENWIN was not able to update the column headings on the following tabs to state "2018 Actuals": App.2-AB, App. 2-K, and App. 2-Z. However, the information contained in the columns is 2018 Actual information.

2 - AMPCO - 4

Reference:

Exhibit 2: Rate Base P45

Preamble:

The evidence indicates System Renewal expenditures in 2009 were $1,059,664 greater than originally filed in the 2009 Cost of Service. Additional 4 kV projects (22F1 and 22F9) were undertaken resulting in an expenditure increase of $300,898. Several other areas exceeded budget estimates, such as subdivisions, cable replacements and manhole rebuild expenditures.

Question:

a) Please explain the need to undertake additional 4 kV projects.

b) Please explain the reasons why several other areas exceeded budget estimates.

Response:

a) ENWIN slightly revised the schedule of 4 kV feeders to assure that "tie" feeders were converted in tandem, preventing the creation of feeder "islands" with no accessible back up source of power when a substation or feeder is down. The revised plan included the addition of 22F1 and 22F9 in order to preclude this risk for other feeders for which these feeders were back-up supplies. As well, other investments were reduced for a variety of reasons and the actual capital spend for 2009 was $1.98M less than budgeted.

b) The budget estimates were prepared based on preliminary designs and average costs based on previous similar projects. The final designs with detailed scope definitions resulted in actual construction costs higher than originally estimated.

2 - AMPCO - 5

Reference:

Exhibit 2: Rate Base P51

Preamble:

The evidence indicates significant expenditures were made in the 27.6 kV systems during 2015. As well, a one-time update of pole inspection database was undertaken as that database was in poor condition and adversely affecting ENWIN's ability to efficiently manage that asset type. These expenditures assisted in the increase in the investment category in 2015.

Question:

a) Please explain the need for increased expenditures in the 27.6 kV systems during 2015.
b) Please explain how the database was adversely affecting ENWIN's ability to efficiently manage that asset type.

Response:

a) While significant expenditures were made on the 27.6 kV systems in 2015, the net capital expenditures in 2015 were only slightly greater than in 2014 with 2015 investments at $16.6M as compared to $16.4M in 2014. The increase in investment in 2015 was not driven so much by an increased need as much as the project selection was such that some larger projects were selected and there were some modest construction cost overruns which pushed the 2015 net capital investment over the 2014 net capital investment.

With regard to System Renewal investments, there was a small amount of 4 kV work to finalize projects that were started in 2014. Replacement of the 27.6 kV system was above the budgeted amount. This was, in part, to offset a late start to a pole inspection project that was needed to replace a badly outdated and unreliable pole condition database. Additionally, one of the large pole replacement projects included underground primary connections ($265k) that were included in the pole replacement expenditure category rather than the cable replacement expenditure category as it was integral to that project. Reactive replacement work was up as 2015 was a year with a number of significant storms which pushed ENWIN’s reliability stats in a negative direction.

For System Service investments, the conductor upgrades exceeded budget due to the 15M11 project, which cost $858k, plus some other minor projects. The System Service new connections expenditure category exceeded the planned spending due to a number of large projects, including:

1. the 15M10 Walker/Cabana project at a cost of $1,860k (including station egress), which was estimated to cost $1,558k; and
2. the WFCU backup feeder connection on McHugh for $1,246k, which was estimated to cost $1,030.

Additionally, SCADA and Station Improvements included an estimate for $1,185k to convert the GM MTS to a 4-wire distribution station.

b) The following explanation of the deficiencies of the old pole database was originally part of ENWIN's internal business case that was used to justify the pole inspection project and provides a thorough description of the issues with ENWIN's inspection system prior to 2015. Some staff names have been removed from this copy.

There are a number of inadequacies with the current pole inspection process, database and historical information which are discussed here. The requirement to inspect poles preceded the requirement to develop an asset management plan by several years. In the beginning, EnWin viewed the pole (and other plant) inspection as a compliance requirement. The initial intent was to identify bad poles and have them changed out fairly quickly. As inspection data was developed, EnWin became more sophisticated regarding its approach to pole asset health. It was realized that the pole asset class needed to be managed and plans developed for determining pole health, tracking remedial treatments, tracking condition, ensuring maximum asset life commensurate with an acceptable level of risk and identifying replacement projects with groups of poles in a given area to minimize cost and customer inconvenience.

Initial inspections were recorded on paper with paper processes for follow-ups. It was then recognized that a pole information database was required and one was developed and implemented. While this was an improvement upon the initial paper process, this database and the information collected suffered from a variety of problems. One of the initial problems was that EnWin's poles are not numbered in the field. The numbering was developed during the inspections when field inspectors identified poles on maps and then let the pole database create a unique number for the pole. This number was eventually transcribed to the GIS map so that the pole asset now had a unique number, but that number only then existed on the map and the database and not on the pole in the field. In discussion with firms that specialize in pole inspection for other Ontario utilities, they report that about 75-80% of utilities have their poles "field numbered". A further problem with the existing database is that it does not adequately identify pole ownership or usage. This causes a problem when lists of poles in poor condition are created. EnWin's pole sustainment program manager (System Planning/Distribution

Engineer) develops lists of projects for replacement of poles in poor condition. It has been determined that these lists cannot be trusted and must be vetted as the pole database does not adequately distinguish streetlight poles from hydro poles. This distinction is accommodated in the new 2012 version of the database. As well, pole ownership is not well documented in the old database. Joint Use Bell poles are changed out through a different process than are EnWin poles due to the ownership difference and it is difficult to develop reliable replacement projects when the pole ownership cannot be relied upon.

Additionally, it was EnWin's practise to re-use pole numbers when replacing a pole. Thus, when a poor pole was replaced, a new pole would be installed and the number of the old pole re-used. As well, there was no procedure to update the pole database with the fact that the pole was now new. Thus, any subsequent listing of poles in poor condition would include those that had already been replaced. The characteristics of the new pole would only be entered into the database when the pole was next inspected, which could take up to 3 years due to the 3-year inspection cycle. This problem has been remedied in the new pole database however the process to update records when a pole is changed out has not been fully developed and implemented and it will take 3 years to complete the updating of the database. The consequence of re-use of the pole numbers is that any listing of the current health of the pole assets is suspect and every project identified through the data is required to be vetted in the field before it can be considered a valid project, budgeted and turned over to Engineering to design. In fact, EnWin cannot state the number of poles that it owns in an accurate fashion as the database does not adequately indicate which poles are EnWin's, Bell's or City of Windsor streetlight poles. Finally, EnWin's agreement with Bell and other attachers is that it is to undertake a Joint Use audit of the poles every 5 years, yet the last Joint Use audit was approximately 12 years ago.

As well, EnWin's means of determining pole health is reasonable but not very scientific. The poles are "sounded" by hitting them with a hammer and listening to differentiate between a solid pole and one that has or is beginning to deteriorate. Clearly, this is a subjective determination and can differ between operators and will be subject to ambient noise interference. As well, EnWin will core drill any poles that are deemed to be "suspect". The sawdust is examined for rot and the level of effort needed during the drilling process is observed. The core drilling weakens the pole to a minor degree and holes are filled with a preservative and capped. This method suffers from the fact that the pole is only sounded above and slightly below ground line and often rot occurs about 8-inches to a foot below grade. Every year, EnWin has poles that fall that have rotten cores but have not been identified as "critical – requiring immediate replacement" – during their last inspections. The 2012 inspection results have been plotted and seem to suggest that there is no correlation between age of the pole and *pole health, which defies logic. This is likely due to our inability to accurately know the age of a pole and accurately determine the health of the pole.*

There are other methods of determining core strength of a pole. These include ultrasonic testing and Resistograph testing whereby a small, thin drill is used and the drilling effort is graphed, depicting whether or not there is rot in the core. This hole is started near ground level and angles down and detects core rot below grade. Pole inspection firms will typically ultrasound and/or Resistograph drill poles that are 20 years or older.

Finally, EnWin has been challenged to keep up with the requirement to inspect its poles on a 3-year cycle. Currently EnWin has 3 regular pole inspectors however only two are actually inspecting poles at any given time. One of these inspectors is currently off due to a long term disability and is unable to work. As well, two recent audits of pole inspection results showed that there was incorrect or missing data in half of the individual pole inspection records.

Current State of Pole Inspection Database: EnWin's pole information is stored on both a Microsoft Access database and an SAP database. The Access database is not considered a "corporate class" database as is the SAP database. The Access database was built and supported by one internal staff resource and requires work to keep it current and usable. The database was upgraded in 2012 and it was consequently not available for the inspectors for a large part of 2012, resulting in fewer poles being inspected that year than necessary to maintain a 3-year inspection cycle. The support staff's current role does not afford them the necessary time to manage this database. There are currently some problems with the database that are unresolved.

Poles are "point" (as compared to "linear") assets and the system of record for EnWin's point assets other than poles is SAP. Consideration was given to converting the Access pole database entirely to SAP at the time that SAP was implemented however it was understood that if there was a future need to add an attribute to the database in SAP then all records would need to be updated individually. This would be a daunting process and likely not worth the effort for the addition of any particular attribute. Also, it was understood that in SAP only health information can be updated through field inspection and attribute information would need to follow a separate process. It was known at the time that additional attributes would be required in a more complete database and that the existing set of pole attributes suffered from errors that were expected to be corrected as inspections continued. A comprehensive correction to the pole database in SAP was not considered to be "in scope" at the time of the SAP implementation.

Consequently, the SAP pole database is a minimal database used primarily for Finance to account for the pole assets. The SAP pole database contains the pole number, type, size, ownership and age. These difficulties led to the decision to keep the poles on the existing Access database.

This decision then complicates the integration of pole information to the GIS system. In fact that integration has not occurred save for the fact that pole numbers are common between the GIS and the Access database. When a new pole is installed, that pole needs to be independently added to the GIS, the SAP pole database and the Access pole database. Similarly, 3 record sets need to be updated when a pole is removed from service. The information that is currently provided when a new pole is set is sufficient to update the SAP database but not the Access database. The Access database is updated during the next inspection cycle, which could take up to 3 years or even longer since EnWin is challenged to keep up with the required 3-year inspection cycle.

Since the pole health inspection data is not on SAP then the inspections are not managed on SAP. Pole inspections are managed on tablets (2) that are carried by the field crews. The work is dispatched to the crews by secondary map. The secondary map with the poles and pole numbers are loaded onto the tablet which has the Access database on it. Crews inspect poles by selecting a pole on the map, then searching in the Access database for that pole number, bringing up the pole information and inputting the attribute and inspection data and then saving that record to the Access database. When all the poles on the map have been inspected the tablet is then given back to CAD who then downloads the information to the corporate (as compared to mobile) copy of the database and that map is removed from the tablet and another put on. The problem with this is that seldom are the inspectors able to access all the poles in a given area (i.e. cannot get into a backyard, etc.) and the inspectors run out of work in an area. Then CAD loads another area into the tablet but do not take the old area off as once a tablet has its map removed with the database updates, those missed poles are no longer available on the tablet for inspection. The unintended consequence of this process is that the tablets keep having more and more work loaded onto them without their records coming back into the system to update the systems of record. In fact, it is not uncommon for months of work (inspections) to be on a tablet. This gives rise to a risk that if the tablet were to corrupt or be lost, damaged or stolen, months of work would be lost, an event that has already happened at least once in the last 2 years.

EnWin has been trying to improve its pole data and collection means through continuous improvement. The paper-based data system has been automated. Data collection has moved from paper data entry by a clerk to field staff data entry on a tablet. The database itself has migrated from paper to a first and now second generation electronic database. Poles have *moved from CAD drawings to having unique pole numbers in a GIS database with each pole having attributes on the map. Despite these improvements, the database and its collection are not sufficient for today's requirements and the reliance that is being put on the data. In fact, EnWin cannot state the number of poles that it owns or has a joint use agreement in place with any degree of confidence in the numbers. It is taken from the data that EnWin has plant on approximately 35,000 poles however that number is thought to be ±5,000.*

In summary, EnWin's pole inspection database is not as accurate as is desired for use as a tool to confidently assess the health of the pole asset class and to determine short and mid-term expenditure levels without vetting each project prior to committing it to the budget. EnWin's inspection method is as well deficient. Joint Use audits and inspections have not been kept up nor does EnWin have the resources it needs to catch up the audits, inspections and data. Poles are a large and important asset class in which EnWin will continue to invest. As such, it is important to have and maintain quality data about this asset class and the need to improve the data and its collection is clear.

2 - AMPCO - 6

Reference:

Exhibit 2: Rate Base P52

Preamble:

The evidence indicates the decrease in System Renewal expenditures in 2016 was due to a reduced investment in the planned pole replacements for 2016. Station equipment investments were also reduced during the year.

Question:

Please explain why planned pole replacements was decreased in 2016.

Response:

System Renewal expenditures were lower in 2016 than 2015 however they were very close to the planned investment level. The 27.6 kV expenditures were $278k above what was planned due to the choice of projects. Additionally, as the pole inspection work progressed, a number of dangerous poles were identified, which were added to the project scope. These dangerous poles were not ascertained when the original plan was set. The costs for reactive pole replacements also exceed planned amounts due to a line replacement caused by a tornado that hit Windsor in 2016 and catch-up work on pole pulling.

For System Service investments, several planned conductor upgrade projects were delayed by customers, including a project at a waste treatment plant supply, due to delays with a customer returning a signed agreement, and delays on other projects with Hydro One and CN Rail pushed a planned 55M3 upgrade to 2017. Additionally, the City deferred a planned road widening replacement and upgrade of a line section on Walker Road due to issues they were having obtaining property on the west side of the road.

2 - AMPCO - 7

Reference:

Exhibit 2: Rate Base P52

Preamble:

The evidence indicates the anticipated increase in System Renewal in 2018 is primarily due to increased investment in the underground transformer sustainment program as well as the underground cable sustainment program for subdivisions.

Question:

a) Please explain the need for the increased investment in the underground transformer sustainment program as well as the underground cable sustainment program for subdivisions.
b) Please discuss 2018 forecast spend compared to actuals.

Response:

a) The increased investment in the underground transformer sustainment program as well as the underground cable sustainment program for subdivisions was mainly caused by the "Rivard Avenue" project that was planned for 2018 due to the poor condition of submersible transformers and underground cable servicing the area. Transformer failures and associated customer complaints in the beginning of the year resulted in the need to expand the scope of the rebuild of the system in the area.

   As well, the Windsor area is the focus of providing "Fibre to the Home" by two telecommunications companies. These companies are investing in fibre infrastructure in nearly every neighbourhood in the City, including the Rivard Avenue area. The telecommunications companies are taking up the remaining available ROW in the street and had installed their plant before ENWIN started its Rivard Avenue project. The take-up of available ROW was unexpected when the Rivard Avenue job was designed and running lines needed to be revised throughout the job due to conflicts with fibre telecommunication lines. As well, many locations could not be open cut and required extensive vacuum excavation to avoid damaging the telecommunication lines which increased the civil works cost for the project.

b) Please refer to the response to OEB Staff - 57 for an explanation of variances between 2018 forecast and actual system renewal expenditures.

2 - AMPCO - 8

Reference:

Exhibit 2: Rate Base P52

Preamble:

The evidence indicates the anticipated increase in System Renewal in 2019 is primarily due to increased investment in the Pole Sustaining program, specifically 27.6kV pole replacements, and the underground Switching Unit Vault Sustainment Program.

Question:

Please explain the need for the increased investments.

Response:

The System Renewal investment planned for 2019 is $2,950k for planned projects and $50k for reactive projects for a total of $3,000k for 27.6 kV pole replacements. This has been the targeted investment level for pole sustainment since 2016. Actual expenditures may vary from that amount however the target investment level as determined from ENWIN's Asset Management Plan is as noted.

The Vault Sustainment Expenditure is a result of a determination that the existing vault which houses transformers and switches for a major downtown high-rise commercial building was a poor location for that equipment. The equipment is at end of life and an alternate, accessible above-ground site is planned for the replacement equipment. Staff has been trying to extend the life of the equipment in the vault by using plastic sheeting to direct salt water spray from an adjacent road from landing on and corroding the equipment however the success of that effort has met its limitations and the equipment is in very poor condition and accessibility is difficult.

2 - AMPCO - 9

Reference:

Exhibit 2: Rate Base P63

Question:

With respect to Appendix 2-G, Service Reliability and Quality Indicators, please add 2018 to the table.

Response:

Please see AMPCO 9 – Attachment 1.

Appendix 2-G
Service Reliability and Quality Indicators
2013 - 2018

Service Reliability

Index	Including outages caused by loss of supply						Excluding outages caused by loss of supply						Excluding Major Event Days					
	2013	2014	2015	2016	2017	2018	2013	2014	2015	2016	2017	2018	2013	2014	2015	2016	2017	2018
SAIDI	1.019	0.813	1.066	0.968	0.730	1.325	0.942	0.808	1.061	0.645	0.724	1.277	0.881	0.813	1.066	0.802	0.730	1.156
SAIFI	2.428	1.911	1.996	2.119	1.751	2.968	2.292	1.849	1.878	1.470	1.697	2.748	2.198	1.911	1.996	1.882	1.751	2.445

5 Year Historical Average

Index	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	0.980	0.903	0.913
SAIFI	2.149	1.928	1.997

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum	2013	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	99.7%	100.0%	99.1%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	N/A	100.0%	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	82.2%	86.8%	75.5%	70.7%	78.2%	76.9%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	99.8%	99.7%
Written Response to Enquires	80.0%	99.9%	99.2%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	98.0%	98.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	2.1%	1.3%	2.8%	3.8%	3.9%	2.9%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	98.5%	94.8%
Rescheduling a Missed Appointment	100.0%	100.0%	N/A	100.0%	N/A	100.0%	99.9%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

2 - AMPCO - 10

Reference:

Exhibit 2: Rate Base P63 Table 2-39

Question:

Please add 2018 data to Table 2-39.

Response:

Please see the response to AMPCO - 9.

2 - AMPCO - 11

Reference:

Exhibit 2: Rate Base Attachment 2-A P14

Question:

The Kinectrics Asset Condition Assessment was completed on April 4, 2018.
Please confirm the vintage of the asset data used in the DSP.

Response:

The Kinectrics Asset Condition Assessment was completed in early 2018 but the engagement started in 2017 and the data provided to Kinectrics was the asset health/inspection data that was current in 2017. ENWIN uses a 3-year cycle for asset inspection so the asset data current in 2017 would have consisted of asset inspection data from 2014, 2015 and 2016 and a partial data set from some 2017 inspections.

The Kinectrics Asset Condition Assessment informed the development of the DSP which was written in latter 2018 and early 2019. The 2019 and 2020 Test Year investment plans were completed in third quarter-2018 and were also informed by the Kinectrics Asset Condition Assessment. The DSP and the 2020 Test Year investment plan was based on the same data set as Kinectrics Asset Condition Study plus a more complete data set from the 2017 inspections.

2 - AMPCO - 12

Reference:

Exhibit 2: Rate Base Attachment 2-A P14

Preamble:

ENWIN indicates its asset condition and replacement rates are informed through an ACA, which identifies an FFA plan of assets expected to require attention over 10 years.

Question:

a) Please provide the ACA from EB-2010-0079.
b) Please provide a copy of the ACA prior to the Kinectrics April 4, 2018 ACA.

Response:

a) The only ACA that has been undertaken prior to the Kinectrics ACA study for this Cost of Service Application was completed in 2007. This ACA is included in AMPCO 12 – Attachment 1.

b) Please see the answer to (a) above.

KINECTRICS

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

September 11, 2007

Stephen L. Cress
Manager
Distribution Department

Ray Piercy
Principal Engineer
Distribution Department

PRIVATE INFORMATION
Contents of this report shall not be disclosed without authority of client.
Kinectrics Inc., 800 Kipling Avenue
Toronto, Ontario, Canada M8Z 6C4

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

September 11, 2007

Prepared by:

Ray Piercy
Principal Engineer
Distribution Department

Peer Review by:

Stephen L, Cress
Manager
Distribution Department

Approved by:

Raymond Lings
General Manager
Transmission and Distribution Technologies Business

Dated: Tuesday, September 11, 2007

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and ENWIN Utilities, PO 11308, April 2, 2007..

REVISIONS

Revision Number	Date	Comments	Approved

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

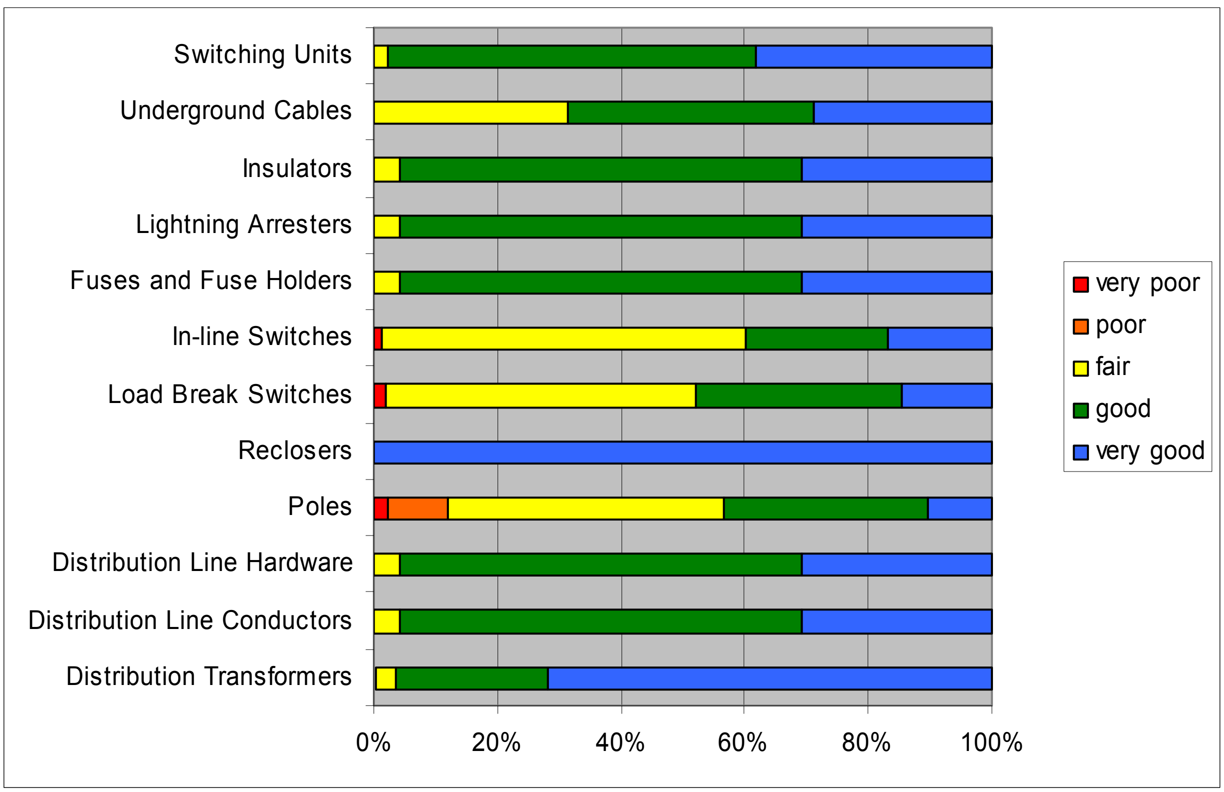
Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

Stephen L. Cress
Manager - Distribution Department

Ray Piercy
Principal Engineer - Distribution Department

EXECUTIVE SUMMARY

This report contains the results of an asset condition assessment and capital replacement plan for the 27.6 kV distribution assets of Enwin Utilities. It is based upon information provided by ENWIN and upon visual inspections and analysis conducted by Kinectrics. The analysis calculated health indices for the twelve major types of component. The health indices can be used as an over all indication of condition and as a basis for estimating the remaining life of components and predicting a required capital replacement plan. The resulting recommended replacement plan identifies the annual capital budget that will be required to maintain the system. If capital spending is below the required level, the condition of the equipment will slowly degrade and increasing customer interruptions and decreased safety can be expected.

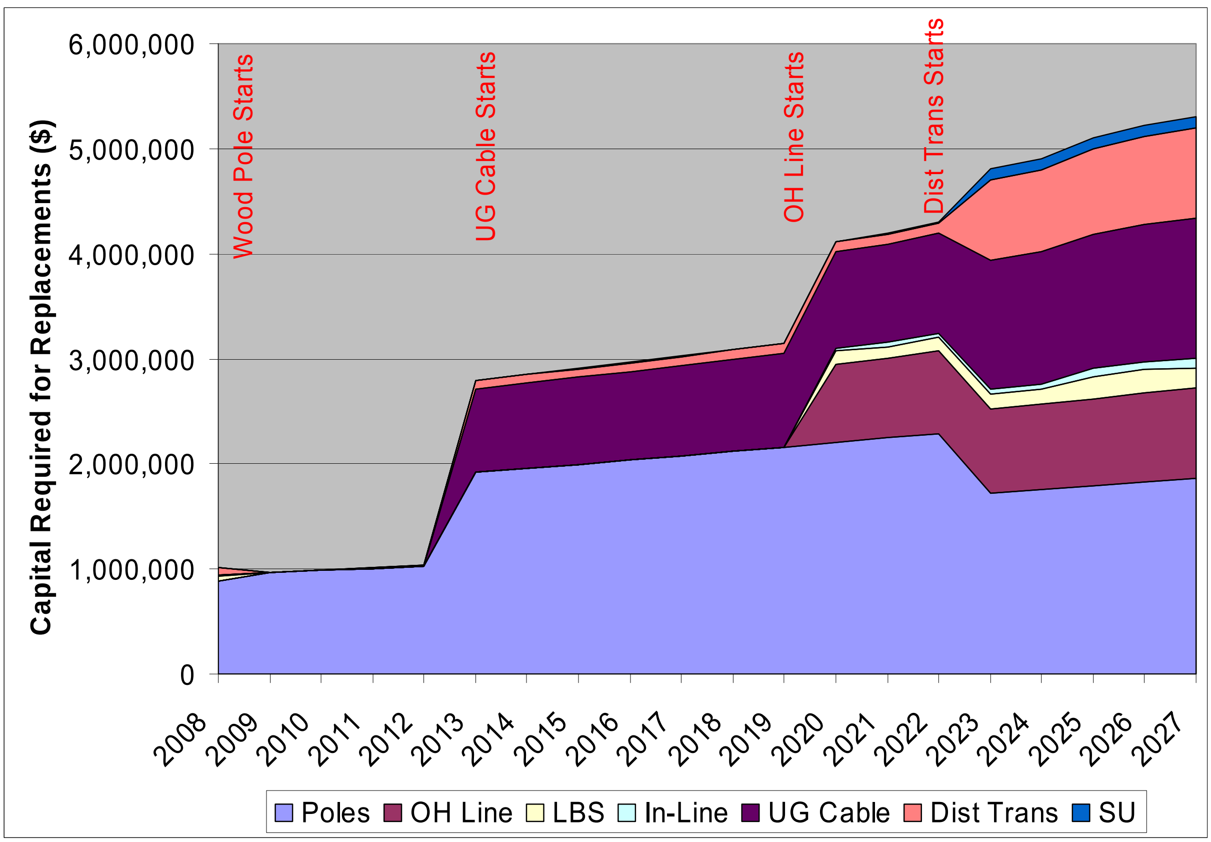


The overall asset condition at ENWIN Utilities is good. The health index results are shown in the following figure. They show that the assets are generally in good condition. Approximately 15% of the poles are in poor condition and need to be replaced. In addition there are a few switches in need of replacement.

The condition monitoring program at ENWIN includes a pole grading program. Recommendations for improving the condition monitoring program of this and other assets are included in the report.

Overall spending on maintenance is at the low end of the range of other utilities in southern Ontario, at $44 in O&M per year per customer and $90 in capital replacement per year per customer. Recent capital replacement programs have reduced overtime and maintenance costs, but capital spending may need to be increased in the future to maintain the system in the present good condition. At the present time, capital spending is only 83% of the annual depreciation.

The following figure shows the recommended capital plan for equipment replacement based on the health indices. It shows that the priority in the near future should be to replace the wood poles that are in poor condition. It also shows that the required capital will increase in about five years as the underground cable will start to need replacement. The further increase in fifteen years will be driven by the need to replace the older overhead lines.



The required replacements over the next twenty years have been grouped by geographic area to identify which areas of the city will require the most work in which years.

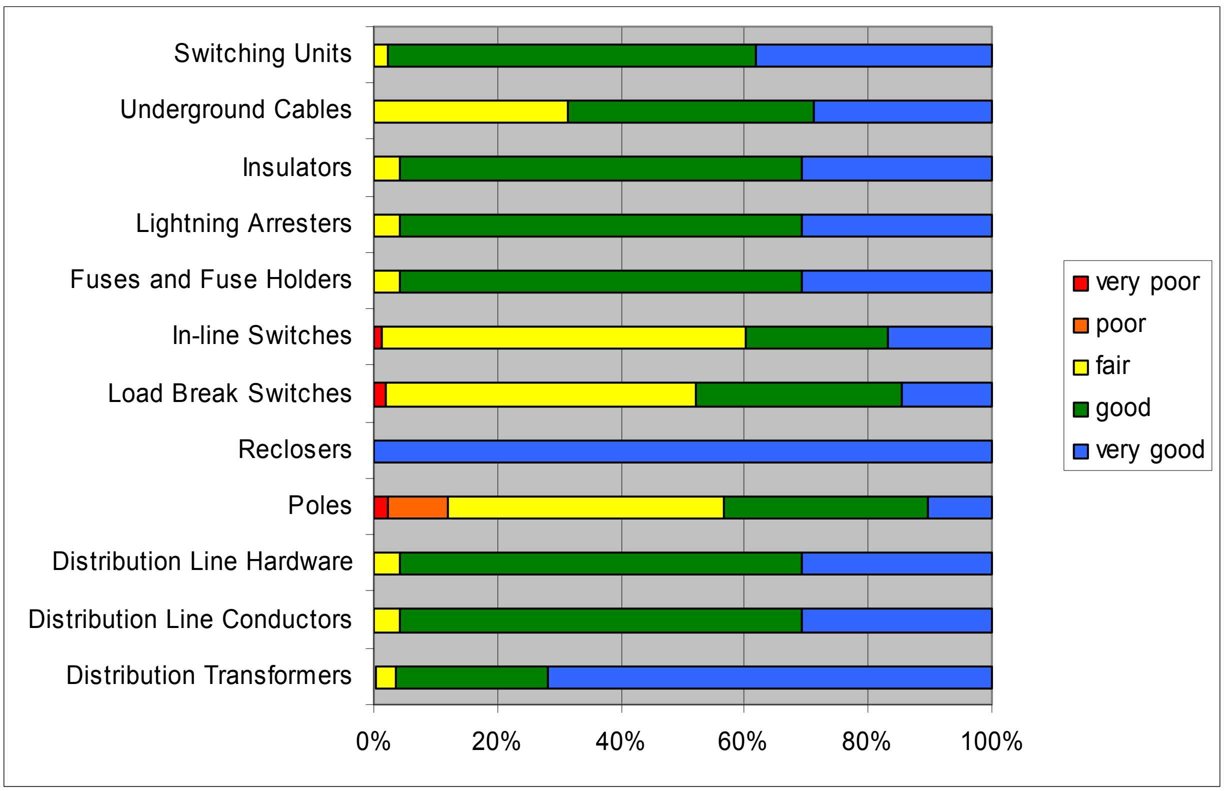
TABLE OF CONTENTS

PAGE

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

1 CONCLUSIONS AND RECOMMENDATIONS

1. The overall asset condition at ENWIN Utilities is very good. The Health Index results are shown in the following figure. They show that the assets are generally n good condition. Approximately 15% of the poles a4re in poor condition and need to be replaced. In addition there are a few switches in need of replacement.



2. The condition monitoring program at ENWIN includes a pole grading program. The following table summarizes the recommended additions to the condition monitoring program.

Asset Type	Available Parameters	Recommended Parameters
Distribution Transformers	age*, loading*	age visual
Distribution Line Conductors	line age, visual*	visual tensile strength
Distribution Line Hardware	line age, visual*	
Poles	rating, line age*, visual*	
Reclosers	age	maintenance cost failure rate
Load Break Switches	line age, visual*	age visual maintenance cost failure rate
In-line Switches	line age, visual*	age visual failure rate
Fuses and Fuse Holders	line age, visual*	
Lightning Arresters	line age,	
Insulators	line age, visual*	age*
Underground Cables	age	failure rate VLF breakdown
Switching Units	age	visual maintenance cost, failure rate
Civil Infrastructure (concrete pads, vaults, ducts)	visual	
Mobile Substations	age	oil breakdown oil moisture oil furan

* not available for individual units, only as a distribution or sample of the population

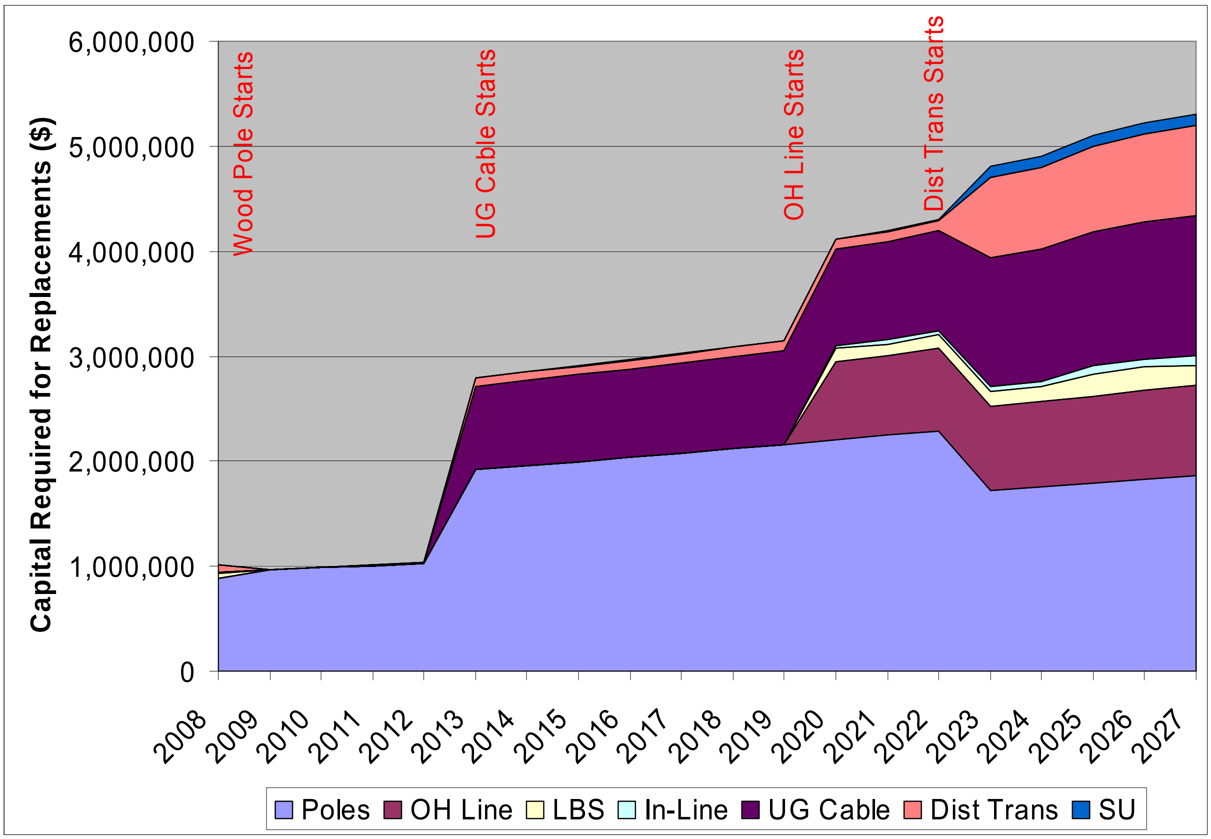
It is recommended that the routine visual inspections assign a condition grade to the inspected component, such as 1 – Excellent (like new), 2 – Good (no visible problems), 3 – Fair (some evidence of degradation), 4 – Poor (obvious problems, near end of life), and 5 – Bad (needs priority replacement).

The expensive tests (tensile strength for overhead conductor and very low frequency (VLF) breakdown for underground cables) are only recommended for use on components at least 80% through their expected life, or on components experiencing a higher than normal failure rate, to determine if condition is the problem. They should not be done more frequently than every five years.

3. It is recommended that ENWIN Utilities replace the poles, distribution transformers, and the rest of the OH line equipment independently, rather than rebuild a section of line replacing all components, whenever this independent replacement is operationally feasible. This recommendation is based on the difference in condition that was found

between these groups of assets. The poles are generally in worse condition than the conductors and transformers and will reach their end of life first.

4. Overall spending on maintenance is at the low end of the range of best practices in the industry, at $44 in O&M per year per customer and $90 in capital replacement per year per customer. Recent capital replacement programs have reduced overtime and maintenance costs, but capital spending may need to be increased in the future to maintain the system in the present good condition. At the present time, capital spending is only 83% of the annual depreciation. The following figure shows the recommended plan.



5. The required replacements over the next twenty years have been grouped, in the report Tables 26 to 32 , by geographic area to identify which areas of the city will require the most work in which years.

6. It is recommended that ENWIN continue the existing targeted replacement programs that are not yet complete, for all assets that will not be made redundant as part of the voltage conversion program. Examples are: porcelain insulators with wood pins, non-tree-retardant UG cable, Dominion disconnect switches.

7. It is recommended that ENWIN change the present policy of replacing wood poles only when they fail. The replacement of wood poles only in response to failure and not based on condition can result in large unplanned capital expenditures. A wood pole is subjected to widely varying loading. A weak pole can go for years without failing because it does not experience a stress close to its design stress. However, if they are not replaced, gradually many poles would be in this condition and then when a large stress comes (a big wind or ice storm) it will fail a large portion of the system all at once.

In addition the CEA standard mandates pole replacement when the design load factor is one or less, because falling lines are a public safety hazard.

If individual pole replacement is adopted it is recommended that Enwin investigate the use of pole re-enforcement and re-treatment with preservatives to delay replacement.

8. It is recommended that ENWIN collect data on end of life for components in their service conditions to further refine this parameter in future analysis.

9. It is recommended that ENWIN consider using a single data base to record condition data. This reduces the cost of asset condition monitoring and most utilities are moving toward this practice. The data recorded needs to be several grades of condition rather than the OK/notOK that is used in maintenance data bases.

10. It is recommended that ENWIN continue to monitor the secondary breaker operation rate in CSP transformers. No planned replacement program is necessary until operation rate increases and becomes a significant operational expense or drain on manpower.

2 INTRODUCTION

As part of their asset management program Enwin Utilities has requested an assessment of the present condition of their 27.6 kV power distribution system infrastructure and a business plan for the strategic replacement of distribution assets to maintain a reliable 27.6 kV system. Together with the regular maintenance program, the result of this assessment will ensure that the equipment will provide optimal service life and that the capital equipment replacement rate is adequate to ensure that there are no large unexpected increased capital requirements in future years.

This report deals with the findings of the asset condition assessment and the equipment replacement capital planning process. The report provides an assessment of the present condition of the assets, an evaluation of the life expectancy identified by geographic region, a review of the asset management program at ENWIN benchmarking it against "best practice" in the industry, and a year by year plan for asset replacement extending out to twenty years.

The assessment has been restricted to the 27.6 kV power system equipment, excluding the substations, land, buildings, office equipment, tools and maintenance vehicles.

3 DOCUMENTATION AND INFORMATION

3.1 Sources Of Information

Requests were made for the detailed information listed in Appendix A of this report. The following summarizes key documentation that was made available by ENWIN Utilities:

- present loading of circuits
- number of wood poles, switches, automated switches, distribution transformers, km of overhead line and underground cable
- age distribution of most assets
- condition grade of poles
- reliability indices
- capital expenditure budget
- book value of capital costs
-

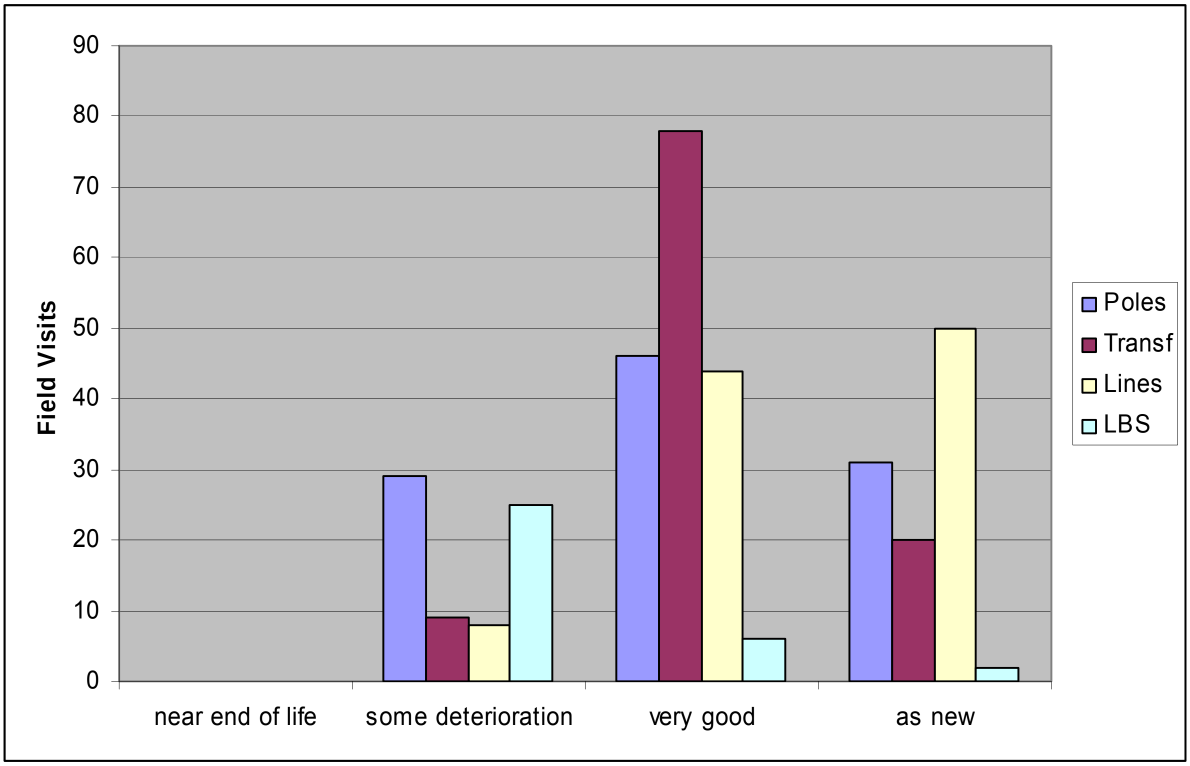
When ages of lines were not available, ENWIN provided an estimate made by experienced staff. This age was recorded on a paper map.

3.2 Field Visits

Field visits to ENWIN Utilities were conducted in May 2007. A sample of 116 locations on the overhead distribution lines were inspected and evaluated. The information obtained in the field visits has been incorporated into the asset condition assessment in report section 3.2. Pictures illustrating the condition of assets are presented in Appendix B. This visual inspection "audit" was used to confirm the asset condition based on age data.

The following figure summarizes the results of the field visits. This figure cannot be used to draw conclusions about the condition of the equipment because a visual inspection is often a poor indicator when used alone.

Figure 1 Results of Field Visits



3.3 Interviews

Additional information utilized in this review was received verbally from interviews with ENWIN Utilities staff. Interviews were conducted with the following staff: Tom Kosnik, Val Ward, Nimal Weeratunga, Doug Collins, Jim St Louis, Shawn Filice.

Information was solicited in each of the interviews on the historical condition, present condition, maintenance activity, and future issues for Enwin Utilities on both Overhead and Underground systems. The notable issues related to asset condition and management are detailed in Appendix C. The information has provided insight into a number of asset issues that were not readily apparent from site inspection and documentation.

In general, it was noted that Enwin is aware of the impact of most asset issues and is taking systematic steps to solve problems as they arise. There have been several targeted replacement programs in the past 20 years, non-tree-retardant UG cable direct buried, lighting arresters, porcelain insulators, and distribution transformers (for overloads and PCB). Squirrel guards, covered conductor and reclosers have been added to improve reliability. The result of these replacement programs is that these assets are in very good condition and the required maintenance has been decreasing. The general strategy has been to spend money on capital replacements and minimize maintenance spending and overtime costs.

The condition of assets is generally thought to be good now, but the ACA is being done to ensure that in the future reliability continues to be good and there are no catastrophic failures or unplanned for, large, increases in capital requirements.

Condition data has not been collected and stored in a common data base. The exception is that there has been an ongoing pole inspection program resulting in a data base with a condition grade on every pole. The inspections have been done by station maintenance staff, who have been trained, but lack experience. As a result some of the individual condition grades are incorrect. Equipment replacements have been done in response to failure rather than based on condition.

Infra-red scans are conducted each year.

The maximum age of the 27.6 kV system assets should be 38 years.

The areas of worst OH asset condition are in the downtown core and some of the back lot single phase lines. Wood poles, in-line switches, underground vaults and some pad mounted switching units are in poor condition. There is no condition monitoring of in-line switches, beyond infra-red scans, and no maintenance is done. This is in contrast to the load break switches that are operated once per year. This area could be improved. Poles are run to failure unless they are on major streets. Most of the poles on major streets are concrete. Underground vault maintenance is considered adequate, with every vault being inspected every year. The switching units that are in poor condition are poor because of moisture build up, and they urgently require maintenance.

The main causes of outages are tree and animal contact, not equipment failures.

There are some old 4/0 copper conductors, but there have been no problems with them.

4 ASSET POPULATIONS

The following assets were included in the condition assessment and capital plan:

Asset Type	Population	Available Condition Parameters
Distribution Transformers	7881	age*, loading*
Distribution Line Conductors	1266 conductor km	line age, visual*
Distribution Line Hardware		line age, visual*
Poles	19666	rating, line age*, visual*
Reclosers	33	age
Load Break Switches	207	line age, visual*
In-line Switches	115	line age, visual*
Fuses and Fuse Holders		line age, visual*
Lightning Arresters		line age,
Insulators		line age, visual*
Underground Cables	576 conductor km	age
Switching Units	176	age
Civil Infrastructure (concrete pads, vaults, ducts)	462 vaults/manholes	visual
Mobile Substations	3	age

* not available for individual units, only as a distribution or sample of the population

5 HEALTH INDEX METHODOLOGY

The condition of the 27.6 kV system assets has been assessed by calculating a health index for each group of assets. A health index is a number between 0 and 100 that indicates the overall condition of the asset, as it relates to its ability to perform its intended function. The index is intended to give a general overview of the asset condition related to its end of life. It is not an indication of whether maintenance is required. Maintenance programs require more detailed information and information on different condition parameters. For example, the contacts of a switch may be in poor condition and need to be maintained, but that will not result in a low health index because it does not relate tot the end of life of the switch.

The health index is based on a set of parameters that indicate the condition of an asset. Each asset type can have a different set of condition parameters. A set of condition parameters was selected for each type of asset at ENWIN. The set was chosen based on the available data provided by ENWIN. The two most common parameters are age and a condition grade based on a visual inspection. For some assets with high populations, such as fuses or line hardware, the age of individual assets was not available and the age of the line itself was used as a surrogate, with all the assets on the line assumed to have the same age.

The Health Index has been calculated with the following equation:

$$HI = \frac{\Sigma (F_i \times W_i)}{\text{Max Score}} \times 100$$

where:

HI is the health index (0-100, 0=bad 100=good)
F_i is the health index factor for the ith condition parameter
W_i is the weight of the ith parameter
Σ is the sum over all i condition parameters
Max Score is the sum if all factors are at the maximum value

The condition parameters and health index factors have been defined in seven steps. The seven steps were selected to match the existing condition grades in data for poles.

If there are one or more condition factors that are considered to be more relevant than the others they are weighted higher (2 or 3). If they are much more relevant, and can indicate end of life all on their own, then the health index is divided by two if the relevant condition factor has a value of 1, and by five if the value is 0. This eliminates masking of poor condition by good values in the less relevant parameters.

The health index is designed so that a value of less than 50% indicates that replacement should be considered and planned for and a value of less than 30% indicates the asset should be replaced as soon as possible. The health index essentially indicates remaining strength, assuming an original design safety factor of 2. So if a pole has a design load of 50 kN and a design load factor of 2, its original strength would be 100 kN. At a health index of 50% it would have 50 kN remaining strength, and should be planned for replacement in the next five years or so. At a health index of 30% its remaining strength would be 30 kN which is well below the design load, indicating that replacement should be a priority.

Table 1 Interpretation of the Health Index

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

The different rates of degradation for different components is handled by altering the “Expected Lifetime” column. The expected lifetime used in this project has been based on industry experience. It is recommended that ENWIN collect data on end of life for components in their service conditions to further refine this parameter in future analysis.

The following example will illustrate the health index calculation method. Poles will be used as the example. There are three condition parameters available for poles, a pole rating from the individual pole inspection program (0 – good to 6 – bad), the age of the line, and a condition grade based on a visual inspection of a sample of poles. Each of the parameters are divided into seven ranges, such as age >10 and <20 years, and each range is assigned a “factor” value. The details for every range of all three condition parameters are provided in Table 7 on page 15. Taking age as an example, the age range “<10 years” is assigned a factor value of 6, indicating the maximum good condition. The age range “>10 <20” is assigned a factor value of 5, indicating slightly worse condition. All the factor values must be high for good condition and low for poor condition because they are used directly in the equation for health index where a high health index is defined as good condition. The factor values for the pole condition ratings are therefore the reverse of the condition ratings, so that a pole rating of 0 (indicating good condition), becomes a factor value of 6 (indicating good condition).

The health index is a weighted average of the three factor values. The equation for health index is:

$$HI = [F_1 \times W_1 + F_2 \times W_2 + F_3 \times W_3] / \text{max score} \times 100$$

where F_1 is the pole rating condition factor
W_1 is the pole rating factor weight (= 3)
F_2 is the age condition factor
W_2 is the age factor weight (=1)
F_3 is the visual condition factor
W_3 is the visual condition factor weight (=1)

max score = 6X3 + 6X1 + 6X1 (= 30)

The weights are chosen using engineering judgment. In this case the individual pole rating was considered to be a better indication of condition than the other two condition parameters.

The following table illustrates the health index calculation for a few different combinations of Condition, Age and Visual Condition factors. The “Condition Rating” factor is the rating from the individual pole inspection program.

Table 2 Example Health Index Calculations

A	B	C	D	E	F	G
Condition Rating Factor	Condition Weight	Age Factor	Age Weight	Visual Factor	Visual Weight	Health Index (A*B + C*D + E*F)/max max=6*3 + 6*1 + 6*1 =30
1	3	0	1	1	1	13
6	3	6	1	6	1	100
4	3	4	1	3	1	63
1	3	4	1	1	1	26
3	3	3	1	3	1	50

The health index for each pole is calculated individually. The poles are then grouped into five ranges of health index <30, 30-50, 50-70, 70-85, >85 as in Table 1 above. The poles were divided into geographic regions, based on the secondary map areas, and the number of poles in each health index range was calculated for each geographic area. These numbers were then used to generate the plan for required replacement capital in each geographic area.

6 ASSET CONDITION ASSESSMENT

6.1 Distribution Transformers

Table 3 Distribution Transformer Health Index Formulation

Condition Parameter	**Weight**
Age	1
Loading	1
Visual Inspection	0
Age (years)	**Health Index Factor**
<10	6
>10 <30	5
>30 <40	4
>40 <45	3
>45 <50	2
>50 <60	1
>60	0
Loading (peak as % of rating)	**Health Index Factor**
<100	6
>100 <110	5
>110 <120	4
>120 <130	3
>130 <150	2
>150 <170	1
>170	0
Max Score = 12	

The visual inspection parameter has been weighted as zero, for distribution transformers only, effectively removing it from the assessment, because it is available on only 102 of the 7,882 distribution transformers and it is not as good an indicator of condition as the age and the loading. Some utilities have a detailed visual inspection of every distribution transformer as part of their condition monitoring system. Condition parameters such as bushing condition (contamination, cracks, chips), tank corrosion, and paint, are graded on a scale from 1 to 5 and the grades are recorded electronically in a data base. This is a “better” condition monitoring system but the cost may not be justified. Very few distribution transformers fail because of conditions that can be detected by the visual inspection.

The Health Index Factors for loading are non-linear in their relation to the load level because loading has a non-linear effect on transformer condition, increasing quickly above 100% load.

The condition parameters for distribution transformers are available only as frequency distributions over the entire population, not as specific values for individual units. It was therefore not possible to calculate a health index value for individual units or for geographic areas.

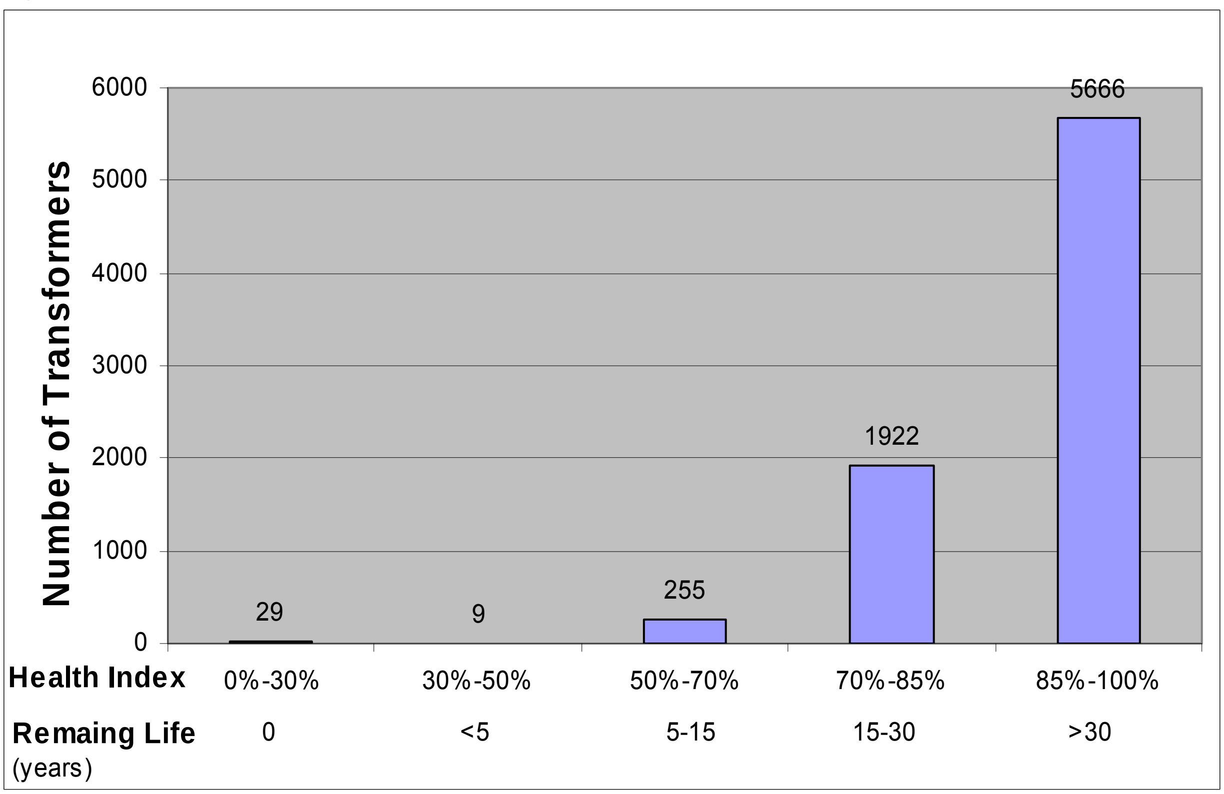
Better indicators of transformer condition, such as furan content of the insulating oil, are not economical to apply to distribution transformers.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

Table 4 Distribution Transformer health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 2 Distribution Transformer Health Index Results



The good condition of distribution transformers indicated by the health index has been confirmed by the interviews with staff and the visual inspections. Many replacements have been made due to load growth and voltage upgrading.

6.2 Distribution Line Conductors

Table 5 OH Conductor Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The visual condition parameters use fewer levels of health index factor because the quality of the input data and its relationship to condition does not warrant more detailed analysis.

The loading was available only for the section nearest the station. Since the data is being analyzed by geographic area, this level of load detail was not sufficient to be used in the quantitative analysis. The load data indicates that in general the lines are not overloaded. Only 20% have peak loads in excess of the line rating and no circuits have average peak loads above the line rating.

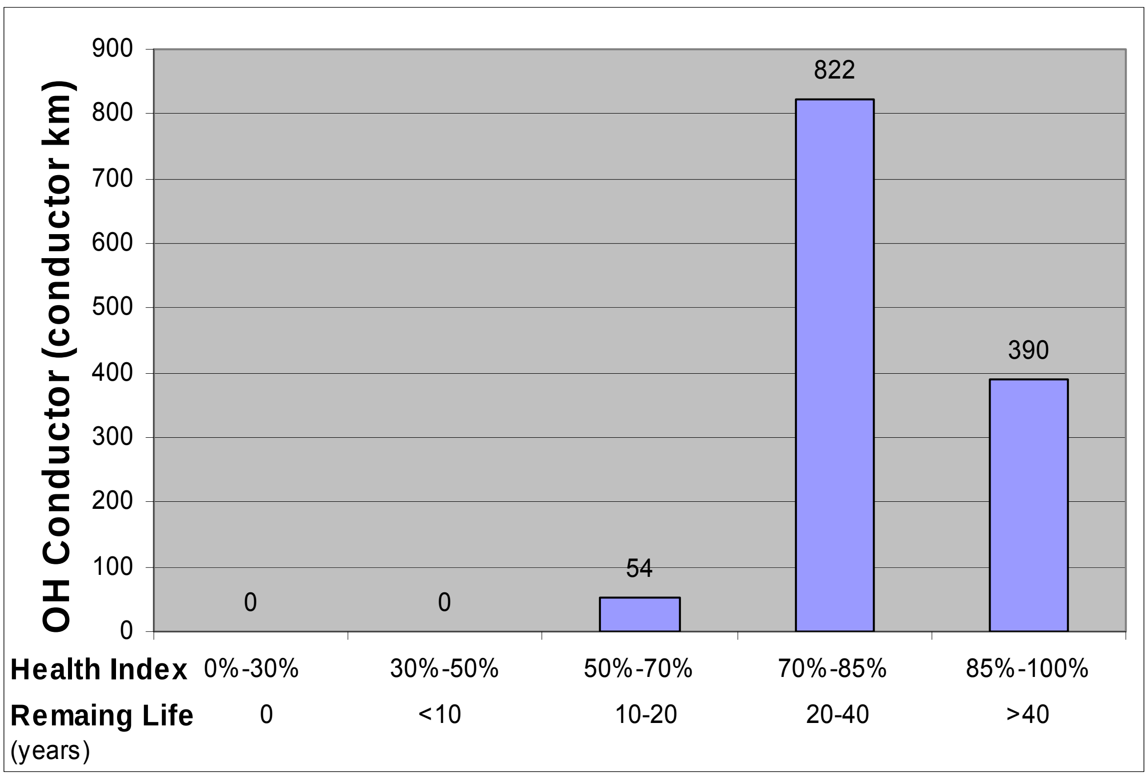
The age was available only from an estimate of the year the line was constructed. However, the accuracy of this should be acceptable because conductor replacements are rare.

Better condition parameters are tensile strength and torsional ductility, but these must be measured on samples removed from the line. The expense of these tests can only be justified if conductor failure rate contributes significantly to safety hazards or reliability problems. It is recommended that ENWIN monitor failure rate and age of conductors.

Table 6 OH Conductor Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 40 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 20-40 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 10 – 20 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 10 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 3 OH Conductor Health Index Results



The good condition indicated by the health index for overhead conductor has been confirmed by the interviews with staff. There have been very few problems experienced, even with very old copper conductor.

6.3 Distribution Line Hardware

Table 7 OH Line Hardware Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

Distribution line hardware includes standoff brackets, braces, clamps and guys.

The health index for distribution line hardware is the same as the health index calculated for overhead conductors, because the age and visual condition data available are the same. There are no other condition parameters that can be used cost effectively to monitor the condition of line hardware.

The present set of condition parameters available at ENWIN is consistent with industry “best practices”.

6.4 Poles

Table 8 Poles Health Index Formulation

Condition Parameter	**Weight**
Pole Rating	3
Line Age	1
Visual Inspection	1
Pole Rating (0 – 6)	**Health Index Factor**
0	6
1	6
2	5
3	4
4	3
5	2
6	1
Line Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <45	2
>45 <50	1
>50	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 30	

The poles had been previously classified in condition ratings based on an individual pole inspection program. This assessment is considered to be more accurate than using the age of the line or the visual inspection of a small sample of poles. The weighting has been set accordingly.

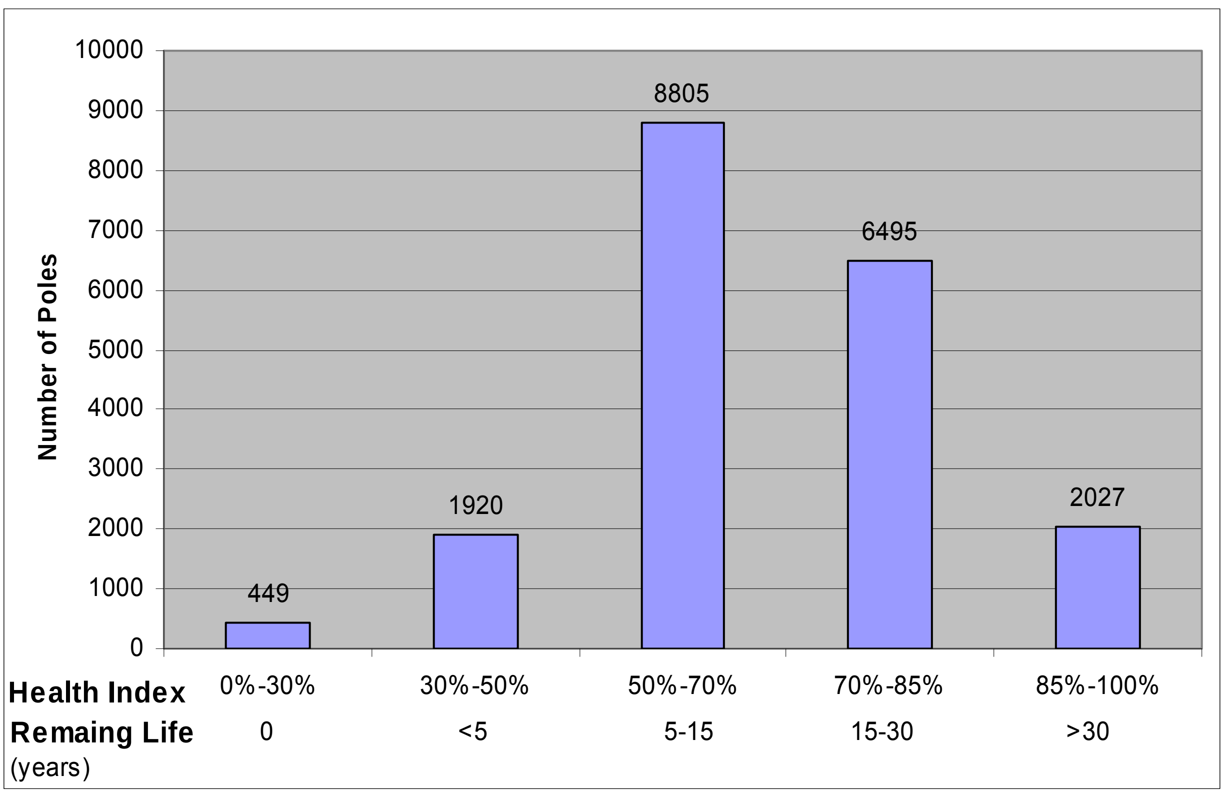
The health index factor for the pole condition rating provided by Enwin has been adjusted to reflect the fact that the Health Index is interpreted as 30% representing end-of-life, but the Enwin condition rating uses a value of 6 as end-of-life. This results in the health index factor being 6 for both Enwin condition ratings of 0 and 1. The health index factor of zero is not used.

The present set of condition parameters available at ENWIN is consistent with industry "best practices". However, the "pole rating" is not defined in relation to the remaining strength of the pole. Defining relative to remaining strength is a "best practice" because it allows the utility to demonstrate compliance with standard CSA C22.3 No1 which requires pole replacement when the strength decreases to the point that the load factor in the design strength calculation is less than one.

Table 9 Poles Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 4 Poles Health Index Results



The wide range of condition of wood poles indicated by the health index has been confirmed by the interviews with staff. Operations staff expressed a growing concern about the number of poles in very poor condition. A recommendation for a pole replacement program has been made in section 10 of this report.

6.5 Reclosers

Table 10 Reclosre Health Index Formulation

Condition Parameter	**Weight**
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

The actual condition of an individual recloser depends heavily on its operating history. The condition degrades quickly with frequent operation and with high fault currents. Condition can be monitored more accurately by recording the number of operations and/or the interrupting I^2t, rather than just tracking age.

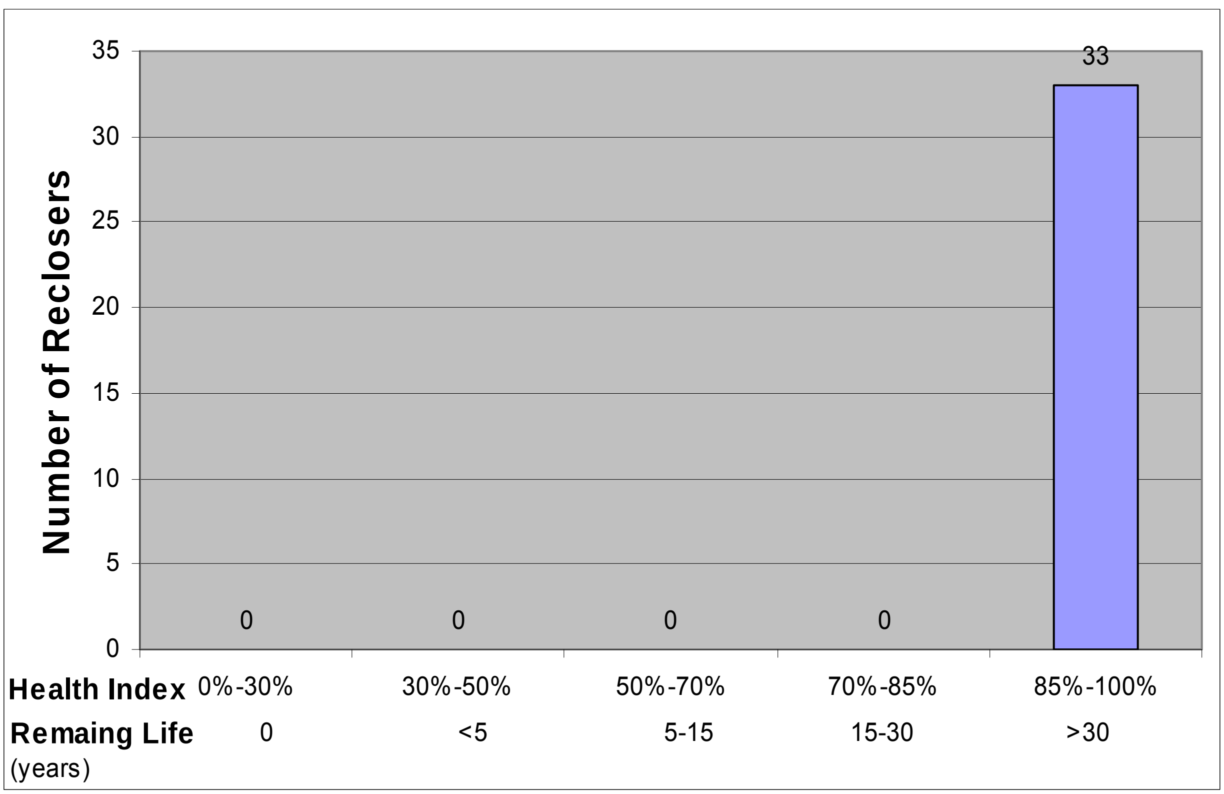
The age of reclosers was only available as an estimate, based on the warranty expiry date. However, the alternative of using the line age as an indication of recloser age was considered less accurate, since most of the reclosers have been added to the system recently.

It is recommended that in the future, ENWIN keep records of the age of individual reclosers and their operation count. Estimating I^2t from operations count can be accomplished by modeling the installation location of each recloser. The reclosers are maintenance free, sealed units so maintenance cost cannot be tracked against replacement cost to indicate end-of-life.

Table 11 Recloser Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 5 Recloser Health Index Results



The excellent condition of reclosers indicated by the health index has been confirmed by interviews with staff and visual inspection. Reclosers have only been installed in recent years in an effort to improve reliability. There have been some failures with units from a specific manufacturer, but these issues are being addressed under warranty with the manufacturer. They are not indicative of the overall condition of the reclosers.

6.6 Load Break Switches

Table 12 Load Break Switch Health Index Formulation

Condition Parameter	Weight
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The actual age of individual load break switches was not available and so the age of the line was used as a surrogate.

The visual condition was available only for a sample of the population (33 of 207 units). Visual condition is a poor indicator of switch condition. The actual condition of an individual switch is better determined by contact resistance measurements, force required to operate, and infrared thermography. However, most of the degradation can be reversed through maintenance, such as replacing contacts, and lubricating linkages, so the condition is not a good indicator of remaining life.

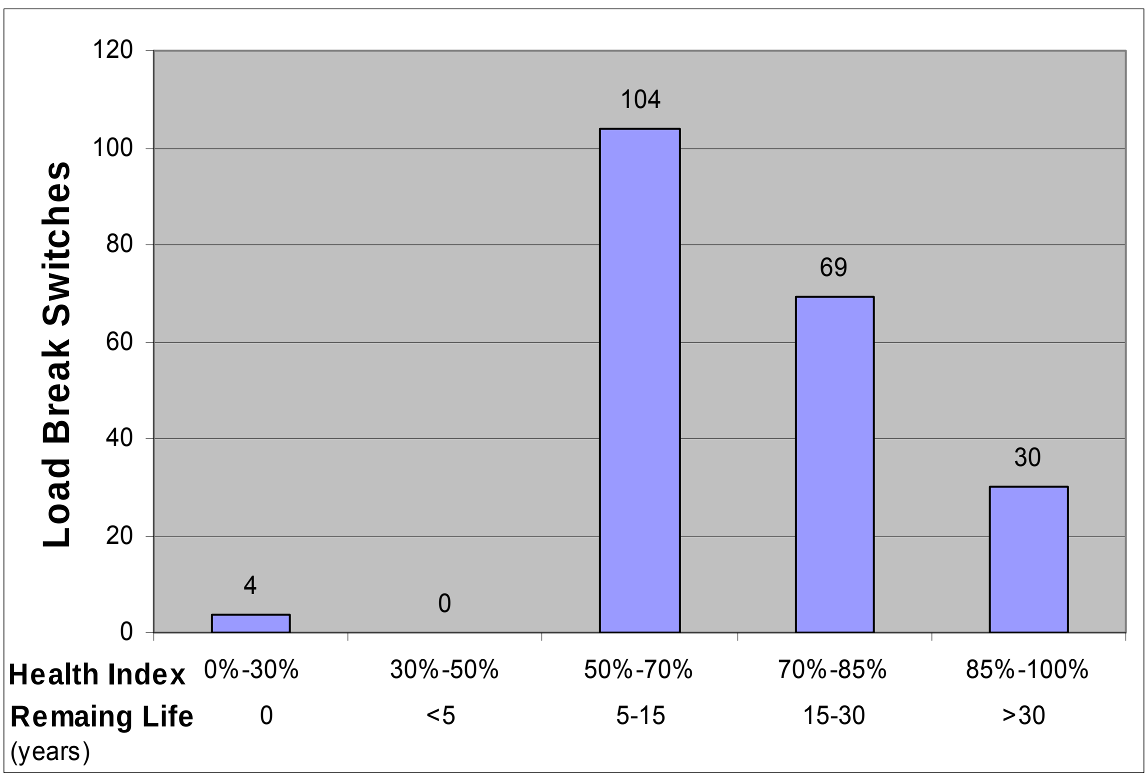
If the annual cost of maintenance was tracked, it could be compared to the replacement cost as an indicator of the economical end of life. Technically the life of the switch can be extended almost indefinitely by maintenance.

It is recommended that in the future, ENWIN keep records of the age of individual load break switches and their annual maintenance costs.

Table 13 Load Break Switch Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 6 Load Break Switch Health Index Results



The generally good condition of load break switches indicated by the health index has been conformed by interviews with staff. The switches are operated annually as part of the scheduled maintenance program and any deficiencies are repaired.

6.7 In-Line Switches

Table 14 In-line Switch Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The actual age of individual in-line switches was not available and so the age of the line has been used as a surrogate.

Visual condition is a poor indicator of switch condition. The actual condition of an individual switch is better determined by contract resistance measurements, force required to operate, and infrared thermography. This level of condition monitoring is not recommended because of the high cost. Since most of the degradation can be reversed through maintenance, such as cleaning contacts and lubricating linkages, the condition of contacts is not a good indicator of remaining life. This leaves age as the best indicator of remaining life.

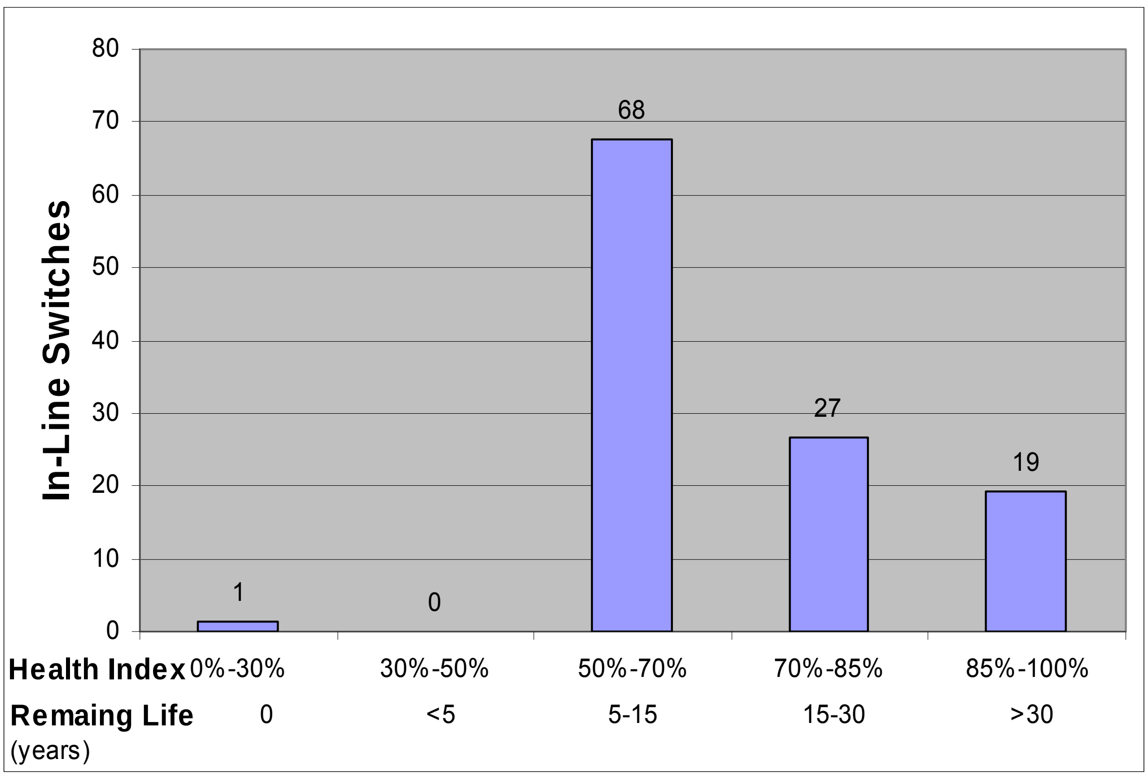
If the annual cost of maintenance was tracked, it could be compared to the replacement cost as an indicator of the economical end of life. Technically the life of the switch can be extended almost indefinitely by maintenance.

It is recommended that in the future, ENWIN keep records of the age of individual in-line switches and their annual maintenance costs.

Table 15 In-line Switch Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 7 In-line Switch Health Index Results



The good condition of in-line switches indicated by the health index has been confirmed by interviews with staff. There have been problems with some designs in the past, but these have been replaced with better designs.

6.8 Fuse Holders

Table 16 Fuse Holder Health Index Formulation

Condition Parameter	**Weight**
Line Age	2
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 18	

There was no data on any condition parameter for fuse holders. Condition can be determined by a combination of visual inspection and laboratory testing of a sample of fuse holders, but this is not recommended because of the low expected benefits compared to the high costs.

The end of life of a fuse holder is usually indicated by cracking of the insulator, or corrosion of the metal parts.

Actual age of individual fuse holders was not available and so the age of the line has been used as a surrogate. This makes the health index for fuses and fuse holders the same as the health index for overhead conductors. It is recognized that this will estimate a health index that is lower than would actually occur in the field because some fuse holders are replaced on an individual basis, not just as part of a line rebuild, and many have been installed at the start of laterals well after the line was built in an effort to improve reliability.

The present set of condition parameters available at ENWIN is consistent with industry “best practices”.

6.9 Lightning Arresters

Table 17 Lightning Arrester Health Index Formulation

Condition Parameter	Weight
Line Age	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Max Score = 6	

Actual age of individual lightning arresters was not available and so the age of the line has been used as a surrogate. This makes the health index for lighting arresters the same as the health index for overhead conductors.

Visual inspection is not capable of detecting the condition of a lightning arrester, unless it has already failed and the disconnector has operated. There is no good condition indicator available for lighting arresters. They should be replaced if the disconnector has operated or the transformer is being replaced.

The present set of condition parameters available at ENWIN is consistent with industry “best practices”.

6.10 Insulators

Table 18 Insulator Health Index Formulation

Condition Parameter	Weight
Line Age	2
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 18	

Actual age of individual insulators was not available and so the age of the line has been used as a surrogate. This makes the health index for insulators the same as the health index for overhead conductors.

The visual inspection can detect broken water sheds, and surface degradation of polymer materials. During the visual inspections conducted as part of this project the condition grade of the insulators was never different than the condition grade of the conductor and over all line.

It is recommended that ENWIN keep records of the age of insulators independently of the age of the line, since the recent insulator replacement program has resulted in some insulators being much newer than the line as a whole.

The present set of condition parameters available at ENWIN is consistent with industry “best practices”.

6.11 Underground Cables

Table 19 UG Cable Health Index Formulation

Condition Parameter	**Weight**
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

Age was the only condition parameter available for underground cables. Most of the cable ages were estimated by ENWIN staff. When age estimates were not available the age of overhead circuits in the same geographic area have been used.

The 40 year end of life assumed here applies to older types of polymer insulated cables. Modern cables with tree retardants and strand blocking are expected to last longer. PILC cables have much longer lifetimes, but individual cable type data was not available.

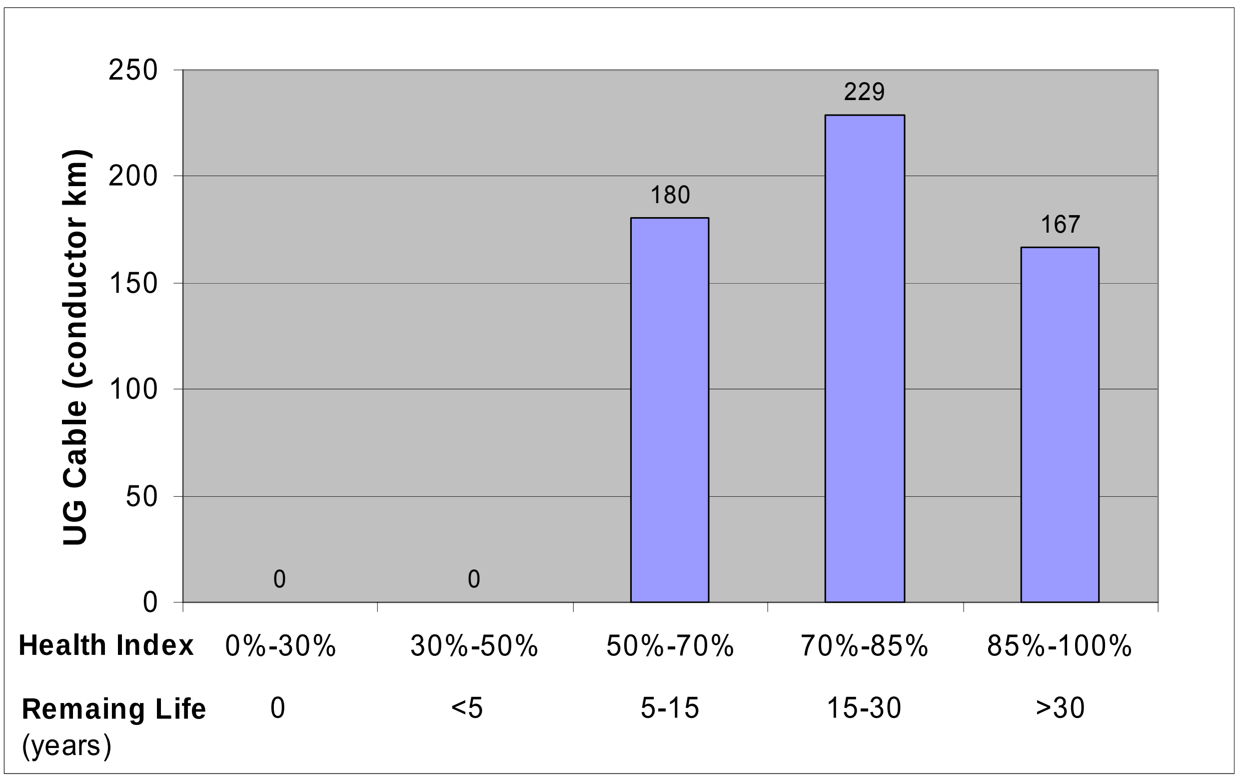
It is recommended that data on cable failure rate be tracked for different cable types, ages, and geographic areas as an indication of cable condition. Present overall failure rates at ENWIN indicate that the UG cables are presently in very good condition overall.

Very low frequency breakdown tests could also be done every few years, on cables older than 20 years, as an additional condition parameter.

Table 20 UG Cable Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 8 UG Cable Health Index Results



The overall good condition of underground cable indicated by the health index has been confirmed by interviews with staff and the low failure rate experienced. The staff interviews identified that there is a targeted replacement program to eliminate the direct buried XLPE cable, about 5% of the installed cable.

6.12 Switching Units

Table 21 Switching Unit Health Index Formulation

Condition Parameter	Weight
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

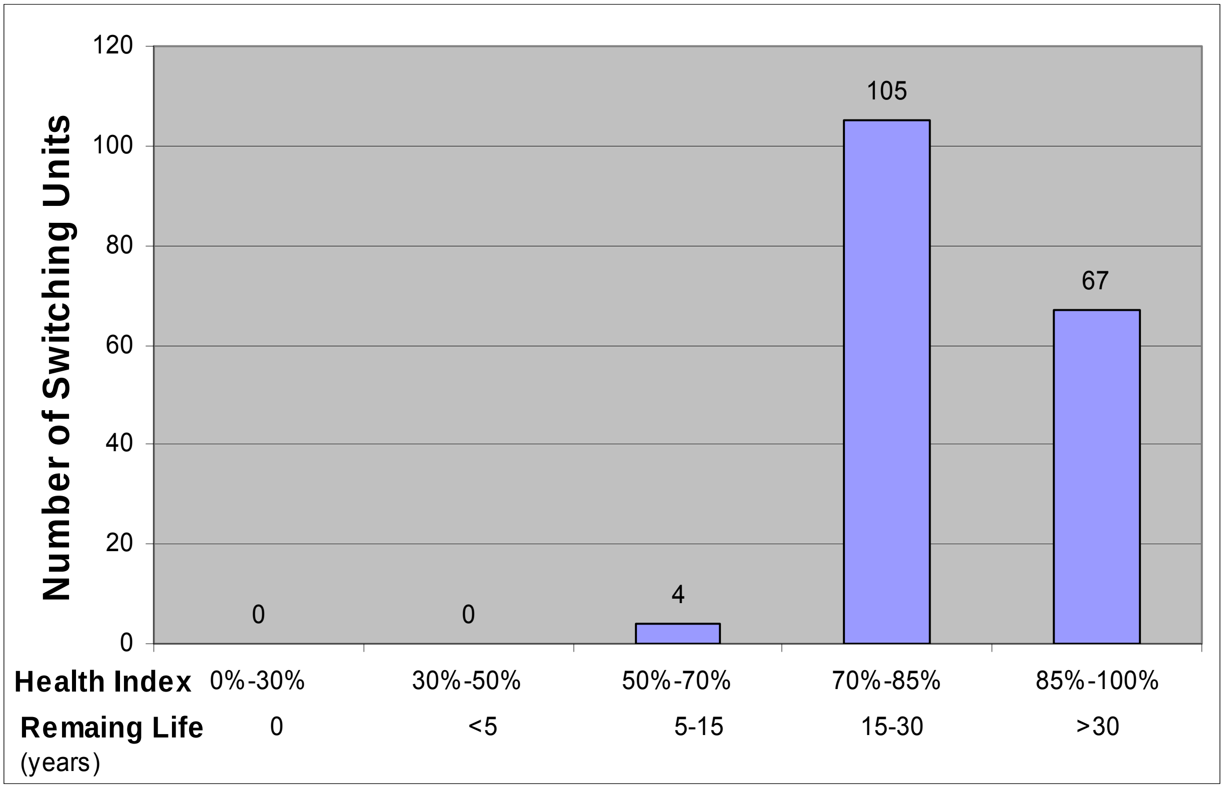
Age was the only condition parameter available for switching units, and only as a distribution based on a sample (113 of 176).

Some utilities have been experiencing high failure rates for switching units. The cabinets and contacts are rusting due to a moist environment and the insulators are becoming contaminated with road salt. A visual inspection has been found to be an effective monitoring technique and an insulator cleaning program can be implemented based on the condition. It is recommended that ENWIN in the future, record a condition grade for switching units based on a visual inspection.

Table 22 Switching Unit Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 9 Switching Unit Health Index Results



The overall good condition of switching units indicated by the health index has been confirmed by visual inspection of a sample of units and interviews with staff. However, the staff interviews did indicate that there are a few units that are experiencing the corrosion problem caused by moisture build up that other utilities are experiencing. If the recommended visual inspection grade is added to the condition monitoring program then health indices calculated in the future will be able to reflect this condition. The present health index analysis is missing these poor condition switches because a visual condition grade was not available on all units.

6.13 Civil Infrastructure

Civil infrastructure includes manholes, concrete pads, underground vaults and ducts.

Age was available for 171 manholes out of a population of 462, but all ages were 1967 and 1968, which was not considered to be representative. A separate project will be conducted on civil infrastructure condition. No health index was calculated as part of this project.

6.14 Mobile Unit Substations

There are three mobile unit substations. The only condition data that was available was age (41, 30 and 24 years). Since these units are only used sporadically, their expected life could be as high as 60 years if they are not overloaded when they are used. Based only on age they would all have a health index of 100%. However, age is not an adequate indicator of substation transformer condition.

A better indication of condition could be made by conducting regular oil tests, particularly furan content, water content, dielectric strength, and interfacial tension. It is recommended that ENWIN conduct these tests every five years.

7 REVIEW OF RELIABILITY STATISTICS

As a component of the asset condition assessment, a review of the reliability statistics provided by ENWIN Utilities was conducted. Reliability statistics are an indicator of the condition of assets, the effectiveness of maintenance, and often the existence of any operational issues.

Table 22 below provides the standard reliability indices utilized by power utilities, indicating the duration, frequency and customer impact of power outages. Data on the cause of outages, particularly the % caused by equipment failure, would be useful in determining the effectiveness of the maintenance program and the general condition of the assets but it was not available.

Table 23 Reliability Statistics

Index	Value (2006)	CEA Urban Utility Average
SAIFI	2.20	1.88
SAIDI	1.38	1.69
CAIDI	0.63	0.95

In general, all of the reliability indices are in the normal range for distribution companies of this size and customer mix, but significantly better than average. From the data provided, it was also noted that the variation in frequency of outages on a year-over-year basis was within the normal range. This better than average performance indicates that asset condition is not seriously affecting the reliability statistics, but comparisons are difficult because weather severity, animal populations, and power system design have large effects on the reliability statistics that are unrelated to asset condition.

Failure rate data was available for some of the asset types and is shown in Table 23. The failure rates being experienced are generally low compared with industry wide expectations. The exception is the reclosers, which are failing at a rate of 10% per year. This is extremely high, given that the reclosers are less than 5 years old. The problem is a specific problem with a particular manufacturer and is being addressed by the manufacturer.

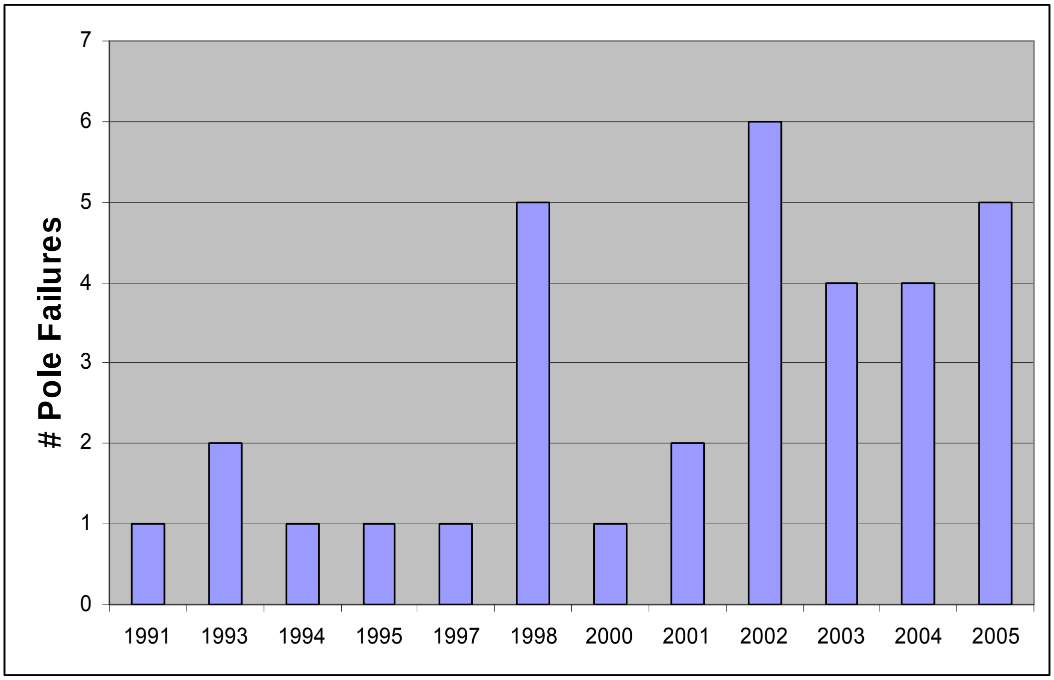
Table 24 Equipment Failures Rates

TYPE	2004	2005	2006
SWITCH		1	1
SU		1	1
RECLOSER		1	3
LI	1	1	1
CABLE		4	5
FUSE HOLDER		1	
LF	2		
ILS	1		
DS	1		
TAP	2		1

The cable failure rate is 5 per 576 conductor km or 0.9 per 100 km per year. Typical industry experience is 1 or 2 failures per 100 km per year.

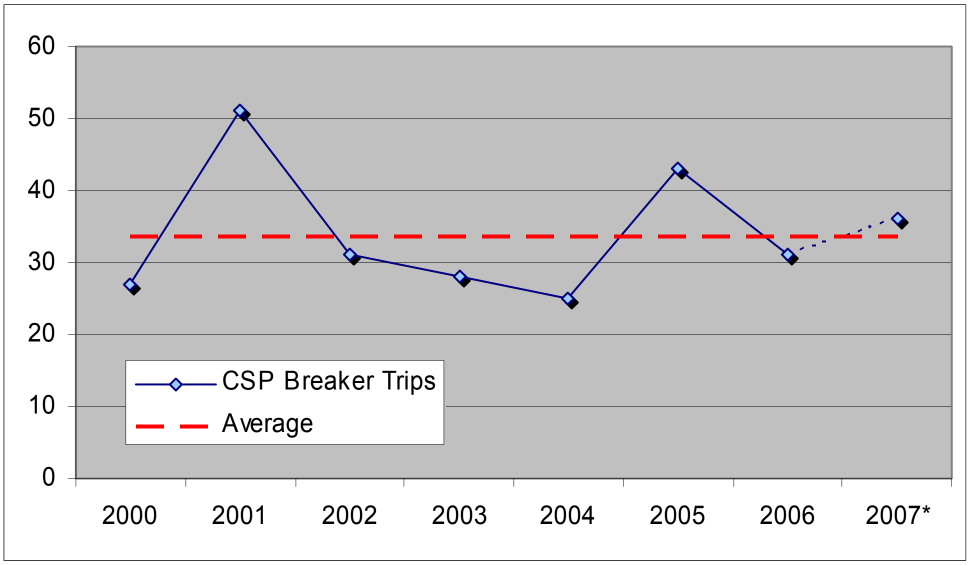
The trend in wood pole failures is shown in Figure 10. Concrete poles have experienced no failures. The failure rate of 5/19666 (0.02%) is low but the trend is increasing. This is an indication that wood pole condition is deteriorating and may require remedial action in the future.

Figure 10 Wood Pole Failure Trend



The trend in secondary breaker trips in completely self protected (CSP) transformers is shown in Figure 11. There is no increasing trend, indicating that the secondary breakers of the CSP transformers are not reaching end of life. There are 2454 CSP transformers installed on the system with an average operation rate of 33.7 per year, which is 1.3%. This operation rate is typical of the industry and also does not indicate end of life.

Figure 11 Trend in CSP Transformer Breaker Trips



* The 2007 value has been estimated by doubling the number of trips from January to July 31 2007 (18).

These reliability and failure rate figures are consistent with the generally good condition found in the health index calculation.

8 REVIEW OF CAPITAL AND MAINTENANCE BUDGETS

As part of the asset condition assessment, the capital and maintenance budgets of ENWIN Utilities were reviewed to ascertain that they were reasonable in light of the asset populations and ongoing maintenance activity.

Table 24 provides a summary of the capital and maintenance budget information. The figures include all distribution equipment including 4.16 kV since separate figures for the 27.6 kV system were not available. The following paragraphs provide some observations on the budget and comments.

Table 25 Summary of Maintenance and Capital Budgets

	ENWIN	Typical[2]
Historic Cost (k$)	189,000	
Net Capital Assets, NBV (k$)	149,000	
Capital Replacement Budget (k$)	7,630	
O&M Budget (k$)	3,380	
Annual Depreciation (k$)	9,203	
Capital Replacement as % of Depreciation	82.9	100 - 140
O&M as % of Capital Replacement	44	45-55
Historic cost /customer ($)[1]	2,230	1,000 - 4,000
Capital Replacement per customer ($)[1]	90	80 - 160
O&M cost per customer($)[1]	40	45 - 65

Note[1] Based on 84,600 customers
All cost are for distribution equipment only, excluding meters, fleet, tools, computers, buildings, land.
Note [2] The “typical” values are taken from annual reports of major utilities in Southern Ontario.

The Enwin figures were provided by their financial department and are as of Dec 31 2006.

Most of the comparison figures for ENWIN Utilities are within the range expected. This indicates that the cost of purchasing and maintaining the systems are similar to other utilities in southern Ontario.

One exception is the size of the equipment replacement budget compared to the annual depreciation. Previous studies have indicated that a typical utility of the size and type of ENWIN Utilities would have a capital replacement budget between 100 and 140% of the annual depreciation of equipment. At ENWIN the capital replacement budget is considerably lower than this. The capital expenditure budget is 7.6 million dollars per year, which is 83% of the 9.2 million dollars depreciation. This could indicate that equipment is not being replaced at a sustainable rate, and that it may need to be increased in the future. However, the capital replacement per customer is in the middle of the range. The 82% may be low because the annual depreciation is high due to higher than average capital expenditures in the previous 25 years. Other utilities may have more fully depreciated systems.

The other metric that is out of the usual range is the O&M cost per customer, which is a bit low. Based on the interviews with staff, this is likely due to a strategy that has recently reduced O&M by focusing on replacement of equipment. Given the low capital replacement budget at the present time, this situation is probably not sustainable. In the future either capital expenditure or O&M, or both, will have to rise.

9 CAPITAL EXPENDITURE PLAN FOR POWER SYSTEM EQUIPMENT REPLACEMENT AT END OF LIFE

Based on information provided by ENWIN Utilities an estimate of the capital plan, for 27.6 kV distribution equipment replacement, was prepared for the next 20 years. The estimated capital plan provides an indication of the likely capital expenditures for equipment replacement. These estimates were done on the basis of the health indexes and the interpretation tables presented in section 5. The capital costs are the dollars required in the year of replacement (not present value). An inflation escalation factor of 2% per year has been included in the estimated costs.

Actual capital replacement requirements will likely be slightly higher than this plan because it does not include other reasons for capital replacement, such as road widening, load growth, equipment obsolescence and improving safety.

Another factor that can increase the capital requirement in any one year is the cost efficiency of replacing many components at once. Rather than replace individual conductors, insulators and hardware based on their condition, it is often cost effective to rebuild an entire line section all at once. This means that some components will be replaced before their end of life, but that the overall long-term cost will be minimized. This plan has been made assuming this efficient replacement strategy. The “OH Line” in Figure 11 includes conductor, insulators and hardware.

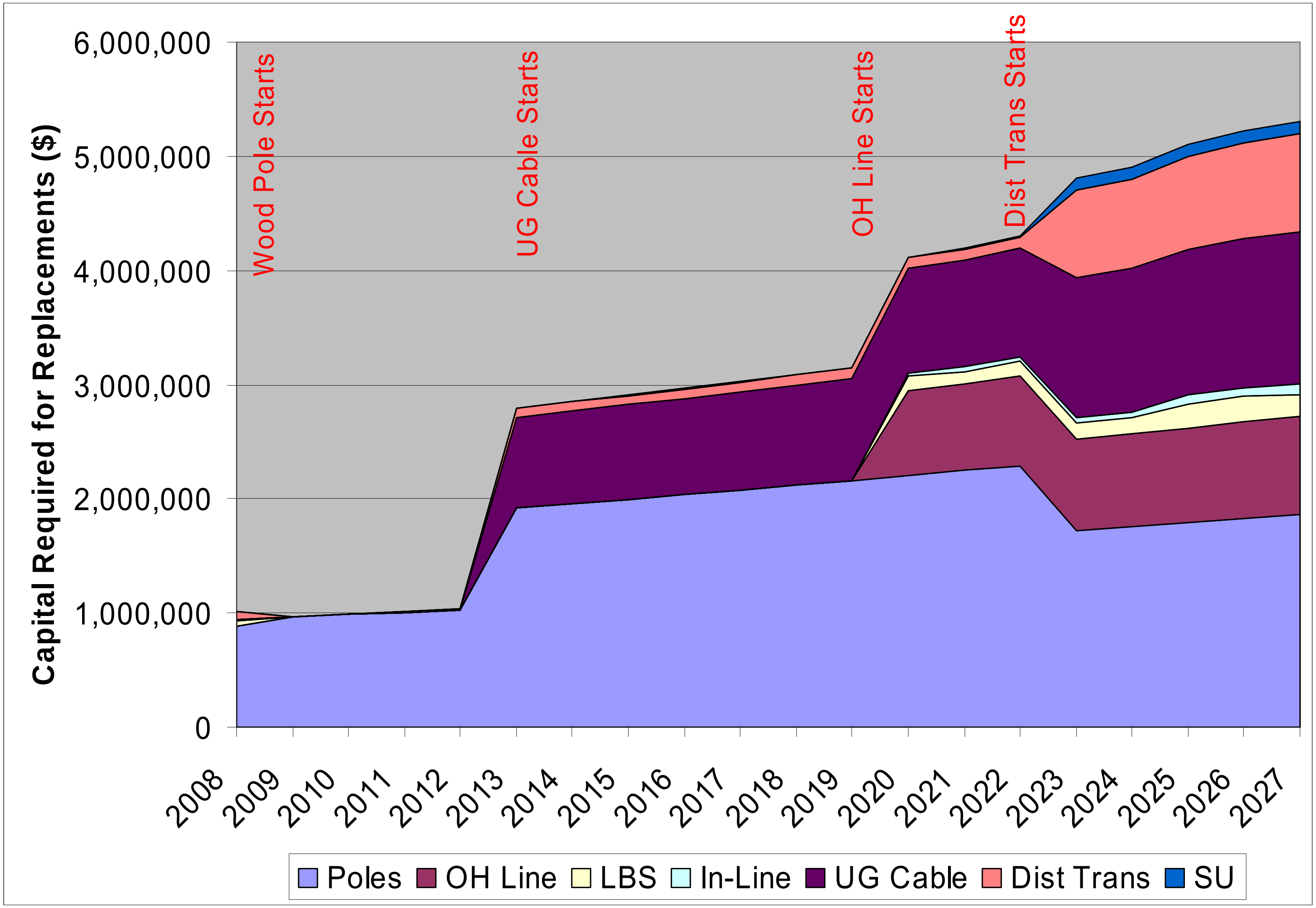
It is difficult to compare the plan in Figure 11 with the present capital spending of $6.1 million because the latter number includes the 4.16 kV and replacements for reasons other than end of life.

The figure shows that pole replacements should begin immediately and double after five years. Underground cable replacements should begin in about five years and continue at a steady rate. In 10-15 years the overhead lines will add significantly to the capital requirements and then in 15 years the distribution transformers will add a significant amount. The required expenditure on switches, although present, will be small in comparison

This plan needs to be combined with the other expected capital expenditures on 4 kV systems and substations to determine a smooth year to year level of capital expenditure. Some of the replacements may have to be moved up to earlier years to create a smooth plan.

It must be stressed that this plan only applies to aging power system equipment and does not include vehicles, tools, buildings, office equipment, or equipment needed for system growth.

Figure 12 Estimated Capital Plan for Power System Equipment Aging Only



10 DEVELOPMENT OF RECOMMENDATIONS

10.1 Review Of Asset Condition Monitoring Program

In comparing the condition monitoring parameters for which ENWIN could provide data with the industry "best practices" there are a few places were a change could be considered by ENWIN. The following table summarizes the available parameters used in section 6 and the recommendations discussed in section 6 for particular asset types.

Table 26 Summary of Recommended Condition Monitoring Parameters

Asset Type	Available Parameters	Recommended Parameters
Distribution Transformers	age*, loading*	age visual
Distribution Line Conductors	line age, visual*	visual tensile strength
Distribution Line Hardware	line age, visual*	
Poles	rating, line age*, visual*	
Reclosers	age	maintenance cost failure rate
Load Break Switches	line age, visual*	age visual maintenance cost failure rate
In-line Switches	line age, visual*	age visual failure rate
Fuses and Fuse Holders	line age, visual*	
Lightning Arresters	line age,	
Insulators	line age, visual*	age*
Underground Cables	age	failure rate VLF breakdown
Switching Units	age	visual maintenance cost, failure rate
Civil Infrastructure (concrete pads, vaults, ducts)	visual	
Mobile Substations	age	oil breakdown oil moisture oil furan

* not available for individual units, only as a distribution or sample of the population

If a parameter is only available as a sample (*) and it is recommended that it be obtained for individual units, then it is included in the "recommended" column without the "*".

It is recommended that the routine visual inspections assign a condition grade to the inspected component, such as 1 – Excellent (like new), 2 – Good (no visible problems), 3 – Fair (some evidence of degradation), 4 – Poor (obvious problems, near end of life), and 5 – Bad (needs priority replacement).

The “maintenance cost” parameter is the expected average annual maintenance cost of the component. It can be compared with the estimated replacement cost to decide when a repairable component has reached the end of its economical life and should be replaced rather than repaired. The exact value at which this occurs should be decided on the basis of lowest net present value which in turn depends on estimates of inflation and the return on capital investment. It is typically about 10%, i.e. when the expected annual maintenance cost is greater than 10% of the replacement cost then the component should be replaced rather than repaired.

The expensive tests (tensile strength for overhead conductor and very low frequency (VLF) breakdown for underground cables) are only recommended for use on components at least 80% through their expected life, or on components experiencing a higher than normal failure rate, to determine if condition is the problem. They should not be done more frequently than every five years.

Failure rate can be tracked to indicate the condition of a group of assets that are a similar age and experience similar service conditions. This is especially recommended for underground cables as it is an industry “best practice”.

It is recommended that Enwin consider defining their pole rating condition parameter in terms of the percentage of the original strength that is remaining. At present each of the levels (0-6) are not defined quantitatively. This make it difficult for Enwin to demonstrate that its pole management program is in compliance with CSA standard C22.3 No.1 Overhead Systems, which requires that poles be replaced when the load factor falls below 1. Typically this occurs at 50 to 66% of original strength. The use of percent remaining strength is standard practice for pole inspection contractors (such as Osmose).

It is recommended that ENWIN consider using a single data base to record condition data. This reduces the cost of asset condition monitoring and most utilities are moving toward this practice. The data recorded needs to be several grades of condition rather than the OK/notOK that is used in maintenance data bases. This represents a significant change to historical practices. When condition monitoring is not being done, and condition checks are only designed to determine if maintenance is required, then the simple OK/not OK information is all that is required. However, this two state information is not adequate for condition monitoring because it does not show gradual deterioration and so does not allow for planned replacement.

10.2 Pole Replacement Program

When a component on a distribution line fails it is always replaced in order to restore service. However, if components are replaced before failure, based on the condition of the component, there are two different strategies that can be employed. One involves replacing individual components one at a time as their condition becomes unacceptable. An alternative strategy is to wait until many components are in poor condition and then rebuild the entire line section replacing all components at once. The choice of strategy depends on a number of factors. Most utilities use a combination of these strategies.

The factors that affect the decision include:

- the relative condition of the different components (are they all degrading together)
- the risks associated with failure, including safety, reliability and cost risks
- the cost effectiveness of group replacement
- the availability of capital for group replacement

In the past Enwin has replaced transformers, lightning arresters, isolating switches and insulators on an individual basis based on condition or on failure rates of specific types of product or manufacturer. However, for poles the strategy at Enwin has been to not replace individual poles unless they failed, or would fail when climbed, and then to rebuild line sections and replace all poles at the same time. This strategy did not require a regular condition assessment of poles.

It is recommended that Enwin adjust its strategy to replace individual wood poles, rather than wait for many to be in poor condition and then rebuilding the line. This recommendation is based on the following rationale:

- the wood poles are in various condition states on most line sections (sometimes due to a partial replacement during voltage upgrading). This makes line rebuilds less cost effective.
- many poles in poor condition scattered throughout the service territory leave the utility exposed to the risk of lengthy restoration activity after a major storm.
- a regular condition assessment of all poles is now being performed at the request of the OEB so extra work is not needed to get the information on which to base individual pole replacement.
- the other components on a line section, such as transformers, insulators, arresters, conductors, are often in much better condition than the poles. This also makes line rebuilds less cost effective.
- Canadian standard C22.3 No. 1 Overhead Systems requires that when a pole's strength has been reduced so that the load factor is less than 1 it should be replaced

Line rebuild can still be recommended in areas where the majority of poles need replacing, or where the majority of other components, such as conductors, insulators, guy wires, anchors, fuse holders etc. need to be replaced.

10.3 Wood Pole Preservation Program

When wood poles are being replaced individually, rather than in groups as part of a line rebuild, the opportunity arises to reinforce and/or retreat individual poles. Most utilities find both of these activities to be cost effective. The decision to reinforce or retreat is always based on lowest long term cost, and often depends on the pricing that individual utilities can obtain from contracting companies.

Poles can be reinforced if they are weak only at certain spots, such as at wood pecker damage, or near the ground line where they often rot the most. The reinforcement can be made by steel trusses, at about $600 per pole or reinforced epoxy wraps at $1400 per pole. This will often extend the life of a pole worth $2000-$4000 by ten or twenty years.

Re-treatment with preservative is harder to evaluate on a cost basis. Once rot is well established re-treatment is not effective. When it will be effective is difficult to determine ahead of time, and the effectiveness is difficult to track after re-treatment.

It is recommended that Enwin investigate both of these options is if adopts a policy of replacing individual wood poles based on condition.

10.4 Completely Self Protected (CSP) Transformer Replacement Program

CSP transformers have been known to have problems with the secondary breaker tripping at too low a load level and causing an unnecessary outage. One of the staff interviews mentioned this issue. There is a potential for this problem to increase as the transformers age. The rate at which customer interruptions are caused by this should be monitored. If the rate becomes unacceptable then a planned replacement program may be necessary. At the present time only the monitoring of the interruption rate is recommended as there is no evidence to show that the rate is unacceptably high at the present time (see Figure 11).

11 GEOGRAPHIC DISTRIBUTION OF EQUIPMENT REPLACEMENT

The following tables show the actual number of components that need to be replaced in each geographic area of the city to make up the capital expenditure plan. Geographic areas are designated by the secondary map numbers. The green, yellow, and red backgrounds indicate increasing levels of replacement. These colours can be used to identify the geographic areas that will require the most work. The years have been grouped into five year groups because the health index end-of-life prediction is not accurate enough to support individual year resolution. This table is intended as a general planning tool. Actual replacements should be done on the basis of equipment condition at the time, not on this prediction.

Switches are not included in the table because they are a small component of the overall expenditure and their columns would be almost all zeros. Distribution transformers are not included because no geographic information was available on distribution transformer condition.

Table 27 Required Replacements by Geographic Area E - I

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
E-1	1	18	18	6	0	0	0	0	0	0	0	0
E-2	0	15	15	9	0	0	0	0	0	0	0	0
E-3	24	19	19	5	0	0	0	0	0	0	0	0
E-4	11	14	14	0	0	0	0	0	0	0	0	604
F-1	2	24	24	8	0	0	0	0	0	0	0	0
F-2	0	13	13	0	0	0	0	0	0	0	0	72
F-3	2	9	9	3	0	0	0	0	0	0	0	0
F-4	11	14	14	1	0	0	0	0	0	600	600	0
F-5	0	0	0	0	0	0	0	0	0	0	0	1800
F-6	5	31	31	5	0	0	0	0	0	3188	3188	0
F-7	5	6	6	0	0	0	0	0	0	1852	1852	926
F-8	6	19	19	22	0	0	0	0	0	0	0	0
G-1	1	40	40	17	0	0	0	0	0	783	783	0
G-2	31	35	35	26	0	0	0	0	0	0	0	0
G-3	0	12	12	19	0	0	0	0	0	0	0	0
G-4	4	8	8	39	0	0	0	0	0	0	0	0
G-5	2	16	16	13	0	0	0	0	0	0	0	0
G-6	14	32	32	1	0	0	0	0	0	0	0	0
G-7	24	52	52	18	0	0	0	0	0	0	0	0
H-1	12	33	33	26	0	0	2638	4397	0	428	428	0
H-2	24	29	29	8	0	0	0	0	0	428	428	0
H-3	19	55	55	14	0	0	0	0	0	300	300	0
H-4	35	47	47	29	0	0	0	0	0	0	0	1851
H-5	7	62	62	8	0	0	0	0	0	0	0	960
I-1	5	35	35	19	0	0	0	0	0	428	428	0
I-2	2	57	57	59	0	0	0	0	0	428	428	0
I-3	0	12	12	6	0	0	0	0	0	0	0	0
I-4	0	24	24	36	0	0	0	0	0	0	0	150

Table 28 Required Replacements by Geographic Area J - L

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
J-1	0	0	0	0	0	0	0	0	0	1229	1229	0
J-2	66	24	24	65	0	0	0	0	0	1229	1229	0
K-1	0	0	0	0	0	0	1512	2520	0	0	0	0
K-10	3	51	51	49	0	0	0	0	0	1710	1710	0
K-11	0	0	0	0	0	0	0	0	0	1206	1206	724
K-2	0	0	0	0	0	0	0	0	0	0	0	0
K-3	11	15	15	3	0	0	0	0	0	0	0	772
K-4	1	63	63	19	0	0	3043	5071	0	0	0	0
K-5	0	51	51	40	0	0	0	0	0	0	0	220
K-6	0	0	0	0	0	0	0	0	0	0	0	1561
K-7	0	0	0	0	0	0	0	0	0	0	0	2345
K-8	0	0	0	0	0	0	0	0	0	1826	1826	304
K-9	0	1	1	1	0	0	0	0	0	0	0	230
L-1	144	34	34	22	0	0	0	0	0	522	522	0
L-10	2	21	21	29	0	0	0	0	0	0	0	0
L-11	30	23	23	36	0	0	2108	3513	0	0	0	603
L-12	2	19	19	0	0	0	1354	2257	0	0	0	0
L-13	0	0	0	0	0	0	0	0	0	0	0	469
L-2	16	56	56	45	0	0	0	0	0	0	0	0
L-3	27	13	13	27	0	0	0	0	0	0	0	0
L-4	2	20	20	37	0	0	0	0	0	0	0	0
L-5	0	12	12	5	0	0	0	0	0	0	0	0
L-6	0	0	0	0	0	0	0	0	0	0	0	0
L-7	64	29	29	24	0	0	0	0	0	0	0	0
L-8	9	58	58	28	0	0	0	0	0	0	0	0
L-9	0	0	0	0	0	0	0	0	0	0	0	0

Table 29 Required Replacements by Geographic Area M - N

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
M-1	26	0	0	8	0	0	0	0	0	13463	13463	0
M-10	67	73	73	29	0	0	0	0	0	51	51	0
M-11	2	26	26	39	0	0	0	0	0	150	150	0
M-12	56	69	69	25	0	0	0	0	0	277	277	0
M-13	0	7	7	3	0	0	0	0	0	0	0	0
M-14	0	0	0	0	0	0	0	0	0	0	0	1304
M-15	0	0	0	0	0	0	0	0	0	0	0	990
M-2	0	0	0	0	0	0	0	0	0	5591	5591	0
M-3	0	0	0	0	0	0	0	0	0	113	113	0
M-4	0	0	0	0	0	0	0	0	0	113	113	0
M-5	0	0	0	0	0	0	0	0	0	113	113	0
M-6	0	0	0	0	0	0	0	0	0	113	113	0
M-7	2	32	32	5	0	0	0	0	0	0	0	0
M-8	2	70	70	28	0	0	0	0	0	0	0	0
M-9	20	49	49	28	0	0	0	0	0	51	51	0
N-1	0	0	0	0	0	0	0	0	0	12494	12494	0
N-10	3	13	13	11	0	0	0	0	0	0	0	252
N-11	0	19	19	12	0	0	0	0	0	0	0	0
N-12	0	78	78	48	0	0	0	0	0	130	130	0
N-13	0	1	1	7	0	0	0	0	0	0	0	4390
N-14	0	0	0	0	0	0	0	0	0	0	0	2969
N-2	16	51	51	26	0	0	0	0	0	7112	7112	0
N-3	37	63	63	28	0	0	0	0	0	713	713	0
N-4	0	0	0	0	0	0	0	0	0	0	0	0
N-5	0	0	0	0	0	0	0	0	0	284	284	0
N-6	9	39	39	34	0	0	0	0	0	113	113	0
N-7	20	43	43	37	0	0	0	0	0	300	300	0
N-8	18	11	11	8	0	0	0	0	0	1122	1122	0
N-9	9	20	20	26	0	0	0	0	0	0	0	3867

Table 30 Required Replacements by Geographic Area O - P

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
O-1	24	58	58	26	0	0	0	0	0	0	0	1776
O-10	2	18	18	2	0	0	0	0	0	0	0	0
O-11	0	29	29	0	0	0	0	0	0	0	0	933
O-12	97	36	36	6	0	0	0	0	0	0	0	3196
O-13	0	2	2	7	0	0	0	0	0	0	0	0
O-2	33	45	45	61	0	0	0	0	0	0	0	0
O-3	8	27	27	4	0	0	0	0	0	113	113	0
O-4	0	0	0	0	0	0	818	1363	0	113	113	0
O-5	38	80	80	10	0	0	0	0	0	0	0	0
O-6	40	54	54	39	0	0	0	0	0	0	0	0
O-7	4	25	25	5	0	0	0	0	0	2407	2407	267
O-8	22	44	44	20	0	0	0	0	0	0	0	2484
O-9	3	50	50	1	0	0	0	0	0	5863	5863	2932
P-1	0	0	0	1	0	0	0	0	0	0	0	0
P-2	0	0	0	0	0	0	0	0	0	0	0	0
P-10	2	11	11	24	0	0	0	0	0	0	0	533
P-11	22	83	83	17	0	0	0	0	0	0	0	0
P-12	0	3	3	37	0	0	0	0	0	0	0	0
P-13	0	0	0	0	0	0	0	0	0	0	0	0
P-3	0	1	1	6	0	0	0	0	0	0	0	0
P-4	19	26	26	55	0	0	0	0	0	852	852	0
P-5	14	44	44	37	0	0	0	0	0	0	0	0
P-6	33	51	51	67	0	0	0	0	0	0	0	0
P-7	11	16	16	9	0	0	0	0	0	652	652	1521
P-8	15	55	55	36	0	0	0	0	0	0	0	0
P-9	5	59	59	1	0	0	0	0	0	0	0	1575

Table 31 Required Replacements by Geographic Area Q - S

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
Q-1-2	0	0	0	0	0	0	0	0	0	0	0	0
Q-2	0	0	0	0	0	0	0	0	0	0	0	0
Q-3	6	47	47	50	0	0	0	0	0	0	0	0
Q-4	27	53	53	33	0	0	0	0	0	0	0	0
Q-5	52	47	47	84	0	0	0	0	0	0	0	0
Q-6	119	62	62	4	0	0	0	0	0	0	0	817
Q-7	20	33	33	36	0	0	0	0	0	0	0	0
Q-8	11	37	37	20	0	0	0	0	0	1488	1488	0
Q-9	2	16	16	51	0	0	0	0	0	879	879	0
R-1	0	0	0	0	0	0	0	0	0	950	950	0
R-2	76	60	60	87	0	0	0	0	0	52	52	0
R-4	47	97	97	26	0	0	0	0	0	899	899	0
R-5	14	78	78	72	0	0	0	0	0	0	0	1067
R-6	2	91	91	49	0	0	0	0	0	0	0	309
R-7	4	7	7	28	0	0	0	0	0	0	0	688
R-8	9	17	17	17	0	0	0	0	0	0	0	490
R-9	1	18	18	40	0	0	0	0	0	879	879	0
S-1	35	46	46	18	0	0	1165	1942	0	518	518	0
S-2	88	41	41	23	0	0	0	0	0	0	0	0
S-3	61	38	38	7	0	0	1354	2256	0	0	0	0
S-4	22	46	46	7	0	0	0	0	0	1055	1055	0
S-5	49	47	47	23	0	0	0	0	0	664	664	0
S-6	69	81	81	27	0	0	0	0	0	0	0	1092
S-7	0	28	28	44	0	0	0	0	0	0	0	3276
S-8	0	26	26	12	0	0	0	0	0	7086	7086	0
S-9	0	16	16	42	0	0	0	0	0	1527	1527	0

Table 32 Required Replacements by Geographic Area T- V

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
T-1	12	9	9	40	0	0	245	408	0	150	150	0
T-10	0	22	22	1	0	0	0	0	0	0	0	0
T-2	29	23	23	58	0	0	0	0	0	150	150	0
T-3	17	39	39	36	0	0	1873	3122	0	1818	1818	0
T-4	32	29	29	17	0	0	0	0	0	0	0	0
T-5	0	2	2	9	0	0	0	0	0	0	0	150
T-6	12	17	17	42	0	0	0	0	0	2287	2287	2287
T-7	6	23	23	46	0	0	0	0	0	0	0	750
T-8	0	0	0	0	0	0	0	0	0	0	0	0
T-9	9	17	17	4	0	0	0	0	0	0	0	0
U-1	53	62	62	10	0	0	0	0	0	0	0	300
U-10	10	39	39	18	0	0	0	0	0	0	0	0
U-2	30	28	28	48	0	0	0	0	0	0	0	0
U-3	0	52	52	48	0	0	0	0	0	175	175	0
U-4	21	30	30	24	0	0	0	0	0	470	470	0
U-5	0	11	11	23	0	0	0	0	0	0	0	0
U-6	11	28	28	17	0	0	0	0	0	0	0	0
U-7	7	10	10	9	0	0	0	0	0	0	0	5042
U-8	1	5	5	22	0	0	0	0	0	0	0	4853
U-9	0	12	12	0	0	0	0	0	0	0	0	0
V-1	6	29	29	38	0	0	0	0	0	0	0	0
V-2	4	13	13	61	0	0	0	0	0	300	300	0
V-3	2	25	25	47	0	0	0	0	0	400	400	400
V-4	0	0	0	0	0	0	0	0	0	0	0	5093
V-5	7	2	2	1	0	0	0	0	0	0	0	0
V-7	0	3	3	15	0	0	0	0	0	0	0	6026
V-8	0	0	0	0	0	0	0	0	0	0	0	11855
V-9	0	0	0	0	0	0	0	0	0	0	0	6250

Table 33 Required Replacements by Geographic Area W - Y

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
W-1	0	4	4	0	0	0	0	0	0	0	0	0
W-2	43	21	21	16	0	0	0	0	0	0	0	2868
W-3	0	0	0	0	0	0	0	0	0	0	0	0
W-4	0	0	0	0	0	0	0	0	0	0	0	0
W-5	0	0	0	0	0	0	0	0	0	0	0	0
X-2	0	13	13	3	0	0	0	0	0	0	0	0
X-3	0	0	0	0	0	0	0	0	0	0	0	0
X-4	0	0	0	0	0	0	0	0	0	0	0	0
X-5	0	0	0	0	0	0	0	0	0	0	0	0
X-7	0	24	24	3	0	0	0	0	0	0	0	4898
X-8	1	6	6	0	0	0	0	0	0	0	0	5972
X-9	3	11	11	1	0	0	0	0	0	0	0	2236
Y-1	0	0	0	0	0	0	0	0	0	0	0	0
Y-2	4	12	12	6	0	0	0	0	0	0	0	600
Y-3	0	0	0	12	0	0	0	0	0	0	0	3179
Y-4	0	0	0	12	0	0	0	0	0	0	0	1488
Y-5	0	9	9	43	0	0	0	0	0	0	0	0
Y-6	0	0	0	0	0	0	0	0	0	0	0	0

12 APPENDIX A Information Requirements for Asset Condition Assessment

The following information is required to provide a basis for asset condition assessment. In some cases a priority level is identified. P1 indicates essential information. P2 indicates that estimation or exclusion of this information will affect the overall assessment by less than 20%.

1. **Maps and Diagrams**
    - Geographic map of system
    - Geographic line and station locations
    - System single line diagrams

2. **Asset Listings, Populations, Inventories, Lengths etc**
    - number, size, of voltage regulators (P1)
    - number, V and I ratings of breakers/reclosers (P1)
    - number and rating of controlled switches (P1)
    - number of manual 3 phase switches (P2)
    - number of manual 1 phase switches (P2)
    - km of overhead 3 phase line by conductor size and type(P1)
    - km of overhead 1 phase line by conductor size and type(P1)
    - insulators by voltage class and material (porcelain, polymer)
    - km of underground 3 phase line (P1) for each cable type and size (ie jacketed\unjacketed, encapsulated jacked, XLPE, tree-retardant TRXLPE) (P2)
    - km of underground 1 phase line (P1) for each cable type and size (P2)
    - km of cable in duct and km of direct buried
    - number of polemounted, padmounted, submersible distribution transformers (P1) for each kVA size (P2)
    - number and type of arresters (polymer, porcelain, gapped, ZnO), cutouts, CLFs
    - number and size of line capacitor banks
    - number of wood poles of various species and treatments (P2)
    - number of concrete poles (P2)
    - number of direct buried steel poles (P2)
    - underground vaults

3. **Age of major assets and age-distribution of minor assets**
    - voltage regulators (P1)
    - breakers/reclosers (distribution P1) (individually P2)
    - controlled switches (distribution P1) (individually P2)
    - manual switches (distribution P1) (individually P2)
    - overhead line (distribution P1) (individually P2)
    - underground line (distribution P1) (individually P2) by cable type (P2)
    - distribution transformers (distribution P1) (individually P2)
    - wood poles (distribution P1) (individually P2)
    - arresters, cutouts, capacitors
    - concrete poles (distribution P1) (individually P2)
    - direct buried steel poles (distribution P1) (individually P2)

- underground vaults

4. Reliability Statistics

- SAIFI, SAIDI, CAIDI for entire system (P2)
- SAIFI, SAIDI, CAIDI for local areas (P2)
- SAIFI, SAIDI, CAIDI for individual circuits (P2)
- SAIFI, SAIDI, CAIDI for individual cable sections, number of splices
- Number of failures, outages, and outage minutes per year by cause of failure (P2)
- Particular reliability issues with individual customers

5. Operation history of major assets and historic operation distribution of minor assets

(operation history is the peak and average loading for transformers, # operations per year for regulators, breakers/reclosers and switches)

- voltage regulators (P2)
- breakers/reclosers (distribution P2)
- controlled switches (distribution P2)
- manual switches (distribution P2)
- overhead line (distribution P1) (individually P2)
- underground line (distribution P1) (individually P2) by cable type (P2)
- distribution transformers (distribution P2)

6. Information on Known Issues

- Elimination of PCB from the system?
- Use of non-tree-retardant cable
- Padmount transformers with drywell canisters
- Porcelain gapped arrester population and failures
- Bolted as opposed to wedge ground connectors
- Loadbreak elbows with aluminum and copper connections and aluminum threaded eye
- Inline switches with polymer insulators prone to failure
- Cable terminations and splices

7. Maintenance Records

- voltage regulators
    i. list of maintenance performed and dates (P2)
- breakers/reclosers
    i. number maintained each year (P2)
- controlled switches
    i. number maintained each year (P2)
- wood pole inspections, testing, and replacement program
- line grounding inspections and maintenance
- inspection program description

i. type of inspection and frequency (P1)

8. Design Standards and Purchasing Specs

- Overhead and underground design standards and purchasing specs

9. Financial Information

- Any existing book value of assets (and depreciation method used)
- purchase price and date for major assets
- replacement cost for major assets or asset groups
- annual capital replacement budget
- itemized annual maintenance budget

13 APPENDIX B Photographs from Visual Inspections

Figure 12 illustrates an old pole with new insulators and hardware. The pole will reach the end of its life before the insulator and hardware do.

Figure 13 Old Pole with New Insulators

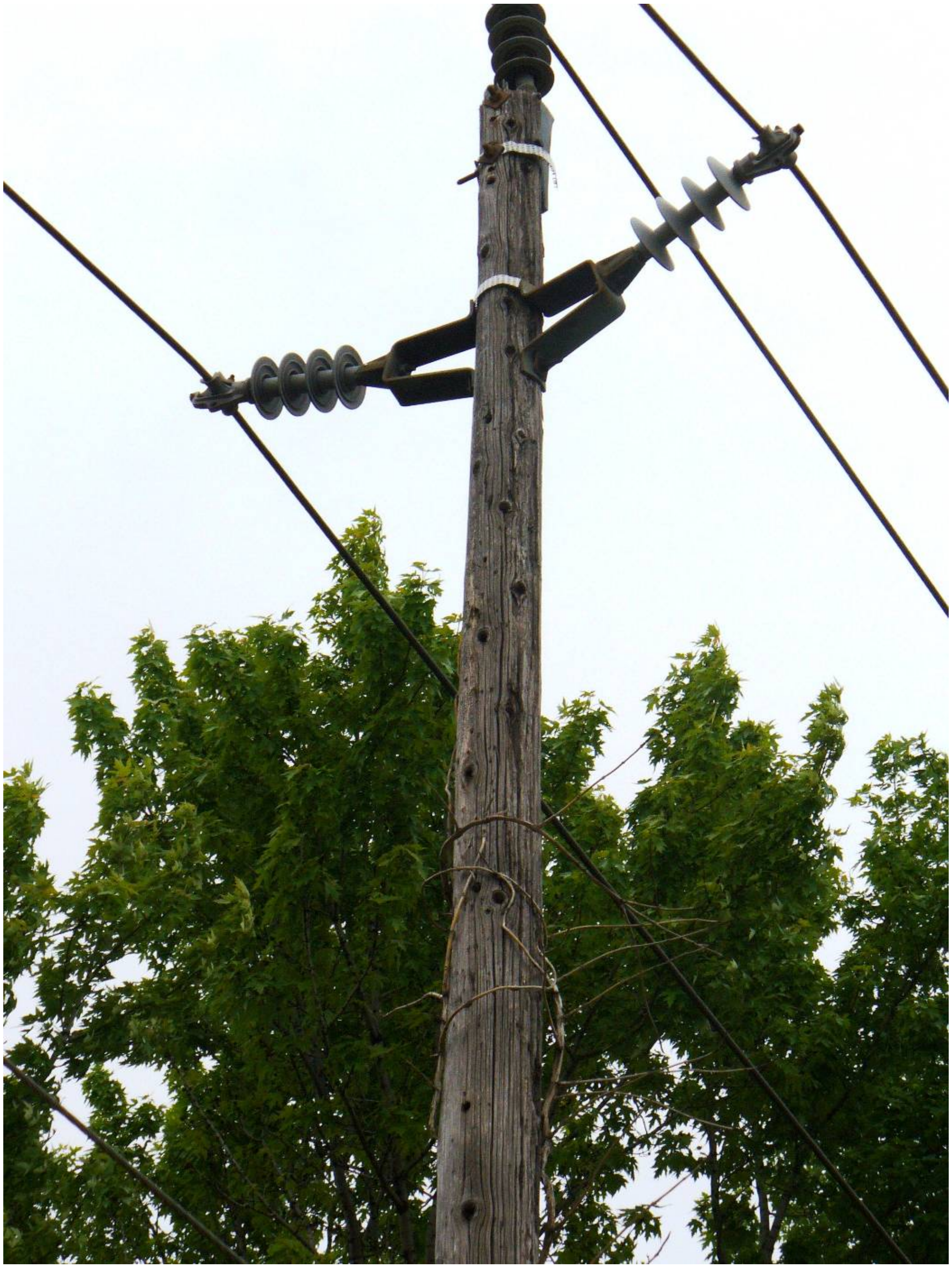


Figure 13 illustrates a problem with back lot lines. The poles in this picture are in good condition but they are inadequately guyed.

Figure 14 Leaning Poles on Back Lot Line

Figure 14 illustrates a concrete pole in poor condition. Water can corrode the exposed rebar and also freeze in the interior of the concrete, cracking the pole and weakening it.

Figure 15 Concrete Pole with Exposed Aggregate

Figure 15 illustrates a conductor that may be in poor condition, but the close splices and the separation of the strands (bird caging) do not necessarily indicate poor mechanical strength. A tensile test is the only reliable condition indicator.

Figure 16 Conductor in Poor Condition

Figure 16 is an example of a transformer in fair condition. It shows signs of deterioration, but the deterioration is not extensive and does not affect its function. Even this small degree of deterioration is rare on the ENWIN system. The transformers are generally in good or excellent condition.

Figure 17 Transformer with Minor Rust

An example inspection form from a field visit is shown below.

Asset Condition Survey
Overhead Distribution

Voltage	27.6	101
Location	Riverside + Green Park	102
sec map	Y-2	

1.0 Remotely Operated Pole Mounted Load Break Switch

brand new
not in service

ID No.		105
	Circle ONLY one	106
1.1 Insulator Condition	A B C D N U	107
1.2 Mechanical Support Condition	A B C D N U	108
1.3 Signs of Over Heating?	A B C D N U	109
1.4 Contact Condition	A B C D N U	110
1.5 Operating Mechanism Condition	A B C D N U	111
1.6 Motor Operator and Control Condition	A B C D N U	112
1.7 Overall Condtion	A B C D N U	113

2 Manually Operated Pole Mounted Load Break Switch

ID No.		117
1.1 Insulator Condition	A B C D N U	118
1.2 Mechanical Support Condition	A B C D N U	119
1.3 Signs of Over Heating?	A B C D N U	120
1.4 Contact Condition	A B C D N U	121
1.5 Operating Mechanism Condition	A B C D N U	122
1.6 Overall Condtion	A B C D N U	123

3 Wood Pole

Location		125
ID No.		126
Age		127
1.1 Holes and Cracks ?	A B C D N U	128
1.2 Rot ?	A B C D N U	129
1.3 Cross arm Condition	A B C D N U	130
1.4 Overall Pole Condtion	A B C D N U	131
1.5 Pole Top Hardware	A B C D N U	
1.6 Guy and Anchor	A B C D N U	
1.7 Conductor	A B C D N U	
1.8 Insulators	A B C D N U	

3 Pole Mounted Transformer

4 pics

Location		133
ID No.		134
1.1 Tank Integrity	A B C D N U	135
1.2 Oil Leak	A B C D N U	136
1.3 Bushing Condition	A B C D N U	137
1.4 Electrical Connections	A B C D N U	138
1.5 Signs of Overheating?	A B C D N U	139
1.6 Overall Transformer Condition	A B C D N U	140

	Name	Date	
Inspector Name and Date	Ray Piercy	2007/05/14	145

(write any comments or concerns on the back of this form)

8/1/2007 Survey Form-1/1 Overhead Distribution VI Form.xls

14 APPENDIX C Asset Condition Information from Staff Interviews

Enwin staff were interviewed to determine the staff perceptions the asset condition and to obtain information about recent equipment replacement programs operational problems. The interviews were conducted April 10, 2007.

Interview with Val Ward - Line Supervisor

Pole condition sampling is horrendous. Sonic test has been used in the past but results were unreliable. They now use boring but results are still not good. A pole graded "OK" in 2004 and when they go to it now it breaks off. The inspections are done by their station maintenance staff, who have been trained, but lack experience.

Their line maintenance is typically done by rebuilding a section of line rather than by maintaining individual components.

In the downtown core the condition of overhead lines is generally poor, especially in areas O1, P1, Q1. Also along Walker Road from the river to Tecumseh Road is old 1/0 conductor. It is scheduled for replacement.

There are some older pin type insulators still near the university. The 27.6 kV switches on the high side of the 4 kV substations are often in poor condition.

All switches are operated once per year as part of standard maintenance program. (actually this is condition monitoring, not maintenance)

There has not been an epidemic of cracked cutouts, only a few isolated incidents.

There has been a problem in the past with in-line switches dropping the conductor, but now they use Ampac switches and have not had a problem. They are starting to use fused in-line switches.

The lightning arrester are 99% polymer.. Over 1000 scout arresters have been replaced in the last twenty years.

Lots of distribution transformers have been replaced. Many in 1988 which was a hot summer and many overloaded. Also many have been replaced as part of the PCB removal program. Many are also new because of the 4 kV conversion program. They convert about 400 poles per year, with 50-60 transformers. This has been going on since 1992.

They have had problems with the secondary breakers on Completely Self Protected (CSP) distribution transformers. They don not use CSP anymore, but there are still many in service.

Pole are run to failure unless they are on a critical circuit. Most of the poles along major streets are concrete. On the back lot lines there are hundreds of rotten poles.

There is an operational concern about how to rebuild 27.6 kV lines. (Nimal thinks just build higher, like a 4 kV conversion.)

The main causes of outages are trees and squirrels. Lots of back lot lines leads to the tree problem.

There is no condition monitoring of in-line switches and no maintenance done. This area could be improved.

The capital replacement program used to be good, but little is done now.

Interview with Nimal Weeratunga

The system is thought to be in good shape right now but the ACA is planning for the future. Work is expected to be needed in five to ten years. The idea is to prioritize areas for replacement.

There has been a problem with some of the new reclosers added to the system in recent years, to improve reliability. They seem to develop vacuum leaks.

The typical conductor life span is 50 years.

The lightning arrester replacement program has been completed.

The in-line switches are thought to be in poor condition.

Wood poles are in poor condition, with a fair amount needing replacement. Concrete poles are in good condition.

The underground cable spreadsheet has new cable included, but does not include single phase laterals.

Many underground vaults/manholes are in very poor condition. PILC and XLPE cables are in good condition.

Pad mounted transformers and pole mounted transformers are in good condition.

Should Enwin use a work order tracking system? They now track for substations, breakers, reclosers, load break switches. Is this the best level to get most of the benefit for the smallest cost (80/20 rule)?

There are no capacitors on 27.6 kV lines. They are all in the stations or on 4 kV lines.

The general strategy has been to use capital replacements rather than do a large amount of maintenance. Equipment is replaced in response to failure, not based on condition.

Infra red scans are contracted out and performed once per year.

The main causes of outrages are trees.

All maintenance is recorded digitally in the Maximo System. A system for tracking work orders is targeted for December 2007.

Interview with Tom Kosnik

The driver for the asset condition assessment is that the management board wants no surprises on budgets. A smooth year to year change is desired. The board also wants to avoid catastrophic failures.

The 27.6 kV system was started in 1970 so the maximum age should be 38 years.

There has been a 10 year replacement program for the old porcelain pin type insulators, replacing with polymer post style. There are still some old wood pin insulators on lines feeding old substations. (COMMENT , may not be worth replacing if 4 kV gone in a few years time)

The old Dominion isolation switches have largely been replaced in recent years.

Only 5% of underground cable now is direct buried. There is a targeted replacement program to replace it with cable in duct ($5M).

There was a large replacement program for distribution transformers in 1988-1990, based on overloading and in the early 2000's based on PCB removal.

There are no known problems with pad mounted transformers. All pad mounted transformers have under oil lightning arresters.

There have been high outage rates due to animal and tree contact in the past. They now use animal guards, covered conductor and a better inspection of tree trimming after the contractor is finished. This is part of a reliability centered program.

There has been an on-going replacement program for lightning arresters since the early 1990's replacing with polymer MOV arresters.

There is some concern about the condition of man holes.

The maintenance program is considered adequate, with no known problems. It uses time based maintenance.

Reclosers have been installed to improve reliability.

Targeted replacement programs have been successful in reducing overtime and maintenance staff level.

Interview with Doug Collins and Jim St Louis –Underground Department

Circuit 25M10 has experienced a large number of failures.

There have been problems with cable splices.

There are no problems with elbows, since 35 kV elbows are used and no load switching is done.

Ducts are all 5" PVC, with a very small amount of old fibre duct.

Vault maintenance is considered OK. Every vault is visited at least once a year.

Old 27.6 kV cable is XLPE, the only PILC is 4 kV. Old direct buried cable is a problem.

Switching units are only in fair condition. Corona can be heard and they have moisture build up. They need maintenance in a bad way. The old Vac-Pac switches have low gas levels.

The sides of the vaults are falling in on some submersible transformer vaults in the Little River Fountain Blue area.

The work order system is more than 20 years old.

Interview with Shawn Filice

The drives behind the ACA assessment are to increase the confidence of the board that the system is in good shape, not falling down. The results will be presented to the OEB.

There are some old 4/0 copper conductors but there have not been any problems. 556 is now standard.

There has been an insulator replacement program for 10 years, starting with the three phase lines. There are still some old insulators around college Ave and Cataraqui and Niagara. Insulators near the expressway are washed spring and fall.

There has been an arrester replacement program, replacing with Ohio Brass.

About 100 in-line switches are worthy of replacement.

Wood poles are in poor condition in areas converted from 4 kV where poles were not replaced.

A summer student was hired to inspect guys, especially bolted connections.

Non-tree retardant XLPE cable has been replaced in 1990's.

Some manholes are on poor shape, with chunks of concrete falling down.

Load break switches are not maintained, just operated every year.

Maintenance is time based, trees trimmed every three years, poles inspected every three years.

There is no specific database for condition information.

DISTRIBUTION

Mr. Shawn Filice	Enwin Utilities (5 copies)
S. Cress	Kinectrics Inc., KL206
R. Piercy	Kinectrics Inc., KL206

2 - AMPCO - 13

Reference:

Exhibit 2: Rate Base Attachment 2-A P16

Question:

With respect to Radial Branch Backup, please provide the number of projects undertaken for each of the years 2012 to 2018 and forecast for 2019 and 2020.

Response:

Please see the requested information in the table below:

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Number of Projects	-	-	-	-	-	3	2	1	2

2 - AMPCO - 14

Reference:

Exhibit 2: Rate Base Attachment 2-A P40 Table 4

Question:

a) Please confirm the target date for each measure.
b) Please advise if SAIDI and SAIFI excludes Major Event Days and Loss of Supply.

Response:

a) Please see the table below:

Metric	ENWIN Target date
SAIFI	Annual Performance
SAIDI	Annual Performance
CAIDI	Annual Performance
MAIFI	Tracking
MED/SED	Annual Performance
Customer Satisfaction Survey Results	Annual Performance
High Voltage Connections	Annual Performance
Telephone Accessibility	Annual Performance
Appointments Met	Annual Performance
Written Response to Enquiries	Annual Performance
Emergency Urban Response	Annual Performance
Telephone Call Abandon Rate	Annual Performance
Appointment Scheduling	Annual Performance
Rescheduling a Missed Appointment	Annual Performance
Reconnection Performance Standard	Annual Performance
Power Quality	Tracking
Worst Performing Feeder	Tracking
Overall DSP Financial Progress vs Plan	Annual Performance
PEG Efficiency Assessment	Annual Performance
Public Awareness of Electrical Safety	Biennial Performance
Compliance with Ontario Regulation 22/04	Annual Performance
Serious Electrical Incident Index	Annual Performance

Crew Visits	Tracking
Distribution Losses	Annual Performance

b) The SAIDI and SAIFI targets come from the 5 year average from 2014-2018. These figures include Major Event Days and Loss of Supply.

2 - AMPCO - 15

Reference:

Exhibit 2: Rate Base Attachment 2-A P45 Table 8

Question:

a) Please provide the number of power quality complaints by year that were due to a natural part of the system operating.
b) Please provide the total number of Power Quality Complaints in 2018 and 2019 to date and the number due to a natural part of the system operating.

Response:

a) The table below shows the number of power quality complaints from major commercial customers that were logged by our System Control Room Operators. The log began in 2010. The count of reports include reports from multiple customers arising from a single system event and reports from customers that are investigating internal power quality issues that span many months, thus generating a large number of reports and reports of perceived power issues that do not coincide with system events.

There is variability in year by year reporting due to various reasons. In 2018 there was a single 230 kV event that produced 6 customer reports. Also a single customer requested a report of all outages impacting their supply in 2018, which resulted in 8 reports being logged for that customer. ENWIN encourages its customers to report the issues they perceive and the number of voluntary reports ENWIN receives are indicative of the customers' participation.

The reports that are logged may or may not be due to a "natural part of the system operating". As noted, some reports are due to electrical issues at the customer's plant that are not precipitated by an event on the distribution or transmission systems.

Power Quality Reports - Major Customer Power Quality Complaints

Year	Total reports
2010	42
2011	32

2012	36
2013	26
2014	24
2015	22
2016	22
2017	33
2018	50
2019 (Jan 1 to Jul 25)	19

b) The table on the following page provides more in-depth reporting for 2018 regarding the nature of power quality complaints that have been received. This summary was prepared for this response through a review of daily logs from 2018.

2018

Non-typical occurances in yellow

Feeder	Breaker Operation	Customer Name	Date	Time	Customer Info	Hydro One - EWP Control Info	LMD-UGD-SAM Info	Comments	ROGER COMMENT
24M5	H1 FEEDER	1	08-Jan-18	0536	ON JAN 10, CUSTOMER REPORTED THAT THEIR GENERATOR TRIPPED OFF LINE ON JAN 8 AT APPROXIMATELY 530AM.	H1 REPORTED TRIP ON MALDEN FEEDER TO COUNTY LOAD.	NIL	CUSTOMER MADE AWARE VIA EMAIL FROM JEFF SCOTT.	COMMON BUS VOLTAGE DIP - H1 FEEDER TRIP
OTHER H1	24M7	2	09-Jan-18	536	INQUIRY ABOUT VOLTAGE DIP	24M7 LOCKED OUT (COUNTY FEEDER)	N/A		COMMON BUS VOLTAGE DIP - H1 FEEDER TRIP
OTHER H1		3	11-Jan-18	0913	VOLTAGE DIP	56M4 CB LOCKED OUT - DIPPED LAUZON TS VOLTAGE	N/A	NOTIFIED	COMMON BUS VOLTAGE DIP - H1 FEEDER TRIP
15M6	CAP BANK	4	12-Jan-18	1448	REPORT VOLTAGE FLICKER	ESSEX TS SC1J CAP BANK TRIPPED OUT AT 1448 - NO CUASE KNOW	N/A	CUSTOMER NOTIFED	CAP BANK TRIPPED AT ESSEX TS
25M5	25M14	5	16-Jan-18	1345	U OF W SAW VOLTAGE ISSUE - NUG STAYED ON-LINE	25M14 LOCK OUT - HO IN EFFECT FOR BLACK & MAC	25M14 CONTACTED WHILE STRINGING IN NEW 25M14/25M13 CCTS ON TEC W		COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP
24M5	NONE	6	17-Jan-18		CUSTOMER REPORTED ON FEBRUARY 12 OF 4 OCCURANCES OF GENERATOR TRIPS IN JANUARY. JANUARY 8, 17, 22 & 29. JANUARY 8 HAD PREVIOUSLY BEEN REPORTED AND RESPONDED TO (SEE REPORT ON JAN 8). REPORTED VIA EMAIL TO ROB SPAGUOLO.	H1 REPORTS NO MALDEN ACTIVITY OR EVENTS ON JANUARY 17, 22 OR 29.	N/A	RESULTS REPORTED TO ROB SPAGUOLO FOR REPORTING TO CUSTOMER.	NO H1 OR ENWIN EVENTS
23M2	23M2	7	28-Jan-18	1016	CUSTOMER REPORTS POWER BLIP ON SUNDAY JANUARY 28	23M2 A/R	A/R DUE TO SQUIRREL CONTACT AT SITE 795	CUSTOMER REPORTED COMPLAINT ON FEB 2. CUSTOMER ADVISED OF A/R AND REASON.	ANIMAL CONTACT
24M2	24M2	8	25-Feb-18	0030	CUSTOMER REPORTS POWER LOSS @ PLANT (24M2 SIDE OF PLANT) REQUESTS UPDATES WHEN FAULT DETERMINED (519-972-8100) CUSTOMER NOTIFIED VIA ADM PERSONNEL THAT TWO FEEDS INTO CUSTOMER ARE 24M1 & 23M6 – REPAIRS TO BE COMPLETED DURING DAYLIGHT HOURS (ALSO FLOODING IN FIELDS	HYDRO ONE REPORTS LOCKOUT ON 24M2 @ 23:59 PM (ATTEMPT TO CLOSE 24M2 CB FAILED 00:01AM)	F.I. @ '24M2-24M2'L.I. INDICATES R-PH & W-PH FAULT – '24M2'24M2'L.I. OPENED – 24M2 CB CLOSED O.K. FAULT STILL REMAINS DOWNSTREAM OF '24M2-24M2' L.I. (PLM PATROL MAPLEWOOD/IRONWOOD)	RED-PH RESLINE MELTED & FELL ONTO WH-PH CONDUCTOR IN FIELD BTWN. '24M2-24M2'L.I. & 24M2 LLTs @ CORNER OF SPRUCEWOOD & MAPLEWOOD WILL WAIT UNTIL DAYLIGHT TO REPAIR AS TRUCKS HAVE NO ACCESS TO FIELD & FIELD FLOODED @ THIS TIME. (ADM CURRENTLY FED FROM 24M1	INSULATOR FAILURE, CONDUCTOR FELL
NONE	NIL	9	02-Mar-18	156	CUSTOMER REPORTS MOMENTARY OUTAGE AT 0156 MARCH 2	H1 REPORTS NO SYSTEM ACTIVITY		KHE MA NOTIFIED NO EWP OR H1 ACTIVITY	NO H1 OR ENWIN EVENTS
15M5	15M5	10	19-Mar-18	0449	VOLTAGE DIP	15M5 A/R AT 449, 458 & 611)	CABLE INCOMING TO JACKSON PARK DEFECTIVE (SITE 611 ON 25M14 - SECTION ON 15M5)		CABLE FAILURE
15M6	15M5	11	19-Mar-18	0449	VOLTAGE DIP (INQUIRY ABOUT DIP AT 611)	15M5 A/R AT 449, 458 & 611)	CABLE INCOMING TO JACKSON PARK DEFECTIVE (SITE 611 ON 25M14 - SECTION ON 15M5)		COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP
55M1	55M1	12	20-Mar-18	1258	INQUIRY ABOUT VOLTAGE DIP	55M1 A/R	55M1 A/R'S WHILE ATTEMPTING TO SECTIONALIZE OUTAGE ON 4M2 CIRCUIT. FOUND BLOWN FUSES AT Y148 (MARKET SQUARE).		FEEDER A/R DURING SECTIONALIZING FAULT ON ADJACENT FEEDER
OTHER H1	C23Z	13	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL
OTHER H1	C23Z	14	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL
OTHER H1	C23Z	15	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL

OTHER H1	C23Z	16	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL
OTHER H1	C23Z	17	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL
OTHER H1	C23Z	18	26-Mar-18	0440	INQUIRY VOLTAGE DIP	C23Z CIRCUIT LOCKED OUT. SKYWIRE DOWN ON HWY401 AT HWY 40 SE OF CHATHAM. SKYWIRE INTO C23Z CIRCUIT.	N/A		H1 230KV CONDUCTOR FELL
55M6	55M6	19	02-Apr-18	0926	REPORT OF MOMENTARY POWER OUTAGE	55M6 A/R	F1245 BLOWN DUE TO SQUIRREL CONTACT		ANIMAL CONTACT
55M1	56M5 & 56M3	20	05-Apr-18	1133	CUSTOMER REPORTS VOLTAGE DIP	56M5 & 56M3 BOTH TRIPPED OPEN CONDUCTOR DOWN JUST OUTSIDE LAUZON TS. Y175 MUST HAVE FELT SYSTEM DIP - 55M1 NOT IMPACTED	ABOVE	CUSTOMER NOTIFIED	CAESARS MUST HAVE FELT 115KV DIP FROM 28KV FAULT AT LAUZON TS (230KV STATION)
55M1	55M1	21	15-Apr-18	0750	VOLTAGE DIP	55M1 A/R DURING SECTIONALIZING ON 4M2 FEEDER (4M2 OUTAGE ON-GOING)	N/A	CUSTOMER NOTIFIED	FEEDER A/R DURING SECTIONALIZING FAULT ON ADJACENT FEEDER
OTHER H1		22	18-Apr-18	2115	VOLTAGE DIP	230KV CIRCUIT OUT OF CHATHAM SS TRIPPED - NOT INCOMING TO WINDSOR	N/A	NOTIFIED	230KV SYSTEM DIP, IMPACT ALL WINDSOR
OTHER H1		23	18-Apr-18	2115	CUSTOMER INQUIRING ABOUT VOLTAGE DIP	230KV CIRCUIT OUT OF CHATHAM SS TRIPPED - NOT INCOMING TO WINDSOR	N/A		230KV SYSTEM DIP, IMPACT ALL WINDSOR
24M1	24M1	24	26-Apr-18	1954	MOMENTARY OUTAGE	24M1 A/R		NO CAUSE FOUND	CAUSE UNKNOWN
NONE	NONE	25	29-Apr-18	1330	CUSTOMER REPORTS VOLTAGE DIP ON SUNDAY APRIL 29 BETWEEN 1330 AND 1500	NO ENWIN SYSTEM ACTIVITY - HYDRO ONE REPORTS NO 115 OR 230 KV SYSTEM ACTIVITY	N/A	FCA NOTIFIED	NO H1 OR ENWIN EVENTS
15M6	15M6	26	06-May-18	0745	MOMENTARY OUTAGE	15M6 A/R - BLOWN LINE FUSE (NO CAUSE FOUND FOR FUSE)	ABOVE	CUSTOMER NOTIFIED	LINE FUSE BLOWN ON FEEDER, NO CAUSE FOUND
23M6	23M3	27	25-May-18	1635	CUSTOMER REPORTS NUG TRIPPED OFF	H1 REPORTS 23M3 (COUNTY FEEDER) A/R/A - CAUSE UNKNOWN	N/A		COMMON BUS VOLTAGE DIP - H1 FEEDER TRIP
24M1	24M1	28	18-Jun-18	2321	MOMENTARY OUTAGE	24M1 A/R		THUNDERSTORM	THUNDERSTORM
24M1	24M1	29	05-Jul-18	2021	MOMENTARY OUTAGE	24M1 A/R		THUNDERSTORM	THUNDERSTORM
23M2	23M2	30	05-Jul-18	1915	Y118 REPORTS POWER OUTAGE	23M2 LOCKOUT	TREE IN LINES ON OJIBWAY PKWY		THUNDERSTORM

15M6	15M6	31	05-Jul-18	2020	CUSTOMER REPORTS VOLTAGE DIP	15M6 A/R DURING THUNDERSTORM - NO RESULTING OUTAGE OR CAUSE	N/A	CUSTOMER NOTIFIED	THUNDERSTORM
24M1	24M1	32	15-Jul-18	1209	MOMENTARY OUTAGE	24M1 A/R		NO CAUSE FOUND	CAUSE UNKNOWN
24M1	24M1	33	15-Jul-18	1210	NO POWER	24M1 A/R	FEEDER PATROLLED NOTHING FOUND	ADM NOTIFIED RESULTS	CAUSE UNKNOWN
OTHER H1	C21J	34	18-Jul-18	0324	CUSTOMER REPORTS VOLTAGE DIP	C21J AUTO RECLOSE - H1 REPORTS NO CAUSE FOUND	N/A		230KV FEEDER A/R NO CAUSE KNOWN
24M1	24M1	35	22-Jul-18	1604	MOMENTARY OUTAGE	24M1 A/R		NO CAUSE FOUND	CAUSE UNKNOWN
24M1	24M1	36	22-Jul-18	1605	MOMENTARY INTERRUPTION	24M1 A/R		CIRCUIT PATROLLED NO CAUSE FOUND	CAUSE UNKNOWN
24M1	24M1	37	29-Jul-18	936	MOMENTARY OUTAGE	24M1 A/R		FOUND LEANING POLE AT SITE P656	LEANING POLE
24M1	24M1	38	06-Aug-18	1824	MOMENTARY OUTAGE	24M1 A/R		THUNDERSTORM	THUNDERSTORM
24M1	24M1	39	06-Aug-18	1557	MOMENTARY OUTAGE	24M1 A/R		THUNDERSTORM	THUNDERSTORM
55M26	56M6	40	23-Aug-18	0731	MOMENTARY INTERRUPTION	56M6 A/R		55M26 ON 56M6 TO ACCOMMODATE H1 REQUEST FOR LOAD RELIEF ON 115KV SYSTEM. FAULT INDICATORS SHOW FAULT CURRENT PASSING THROUGH 55M26-ILS-SOUTH RISER; 55M26 FEEDER PATROLLED IN AREA NO CAUSE FOUND.	CAUSE UNKNOWN
23M6	23M6	41	09-Sep-18	2004	MOMENTARY INTERRUPTION	23M6 A/R		PATROLLED NO CAUSE FOUND	CAUSE UNKNOWN
24M1	24M5	42	17-Sep-18	1004	VOLTAGE DIP	24M5 A/R		24M5 A/R - NO CAUSE FOUND – STATION VOLTAGE DIP FELT BY ADM	COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP
OTHER H1	C22J	43	17-Sep-18	2241	MOMENTARY INTERRUPTION	C22J A/R: C23J OUT OF SERVICE THUS MOMENTARY OUTAGE FELT AT MALDEN & KEITH TS'S		H1 REPORTS NO CAUSE OF A/R KNOWN	230KV FEEDER A/R NO CAUSE KNOWN
OTHER H1	C22J	44	17-Sep-18	2241	MOMENTARY OUTAGE	C22J A/R: C23J OUT OF SERVICE THUS MOMENTARY OUTAGE FELT AT MALDEN & KEITH TS'S		H1 REPORTS NO CAUSE KNOWN FOR A/R	230KV FEEDER A/R NO CAUSE KNOWN
OTHER H1		45	21-Sep-18	1306	VOLTAGE FLUCTUATION	OGCC REPORTS ARA ON NON-ENWIN FEEDER AT KEITH TS			COMMON BUS VOLTAGE DIP - H1 FEEDER TRIP
15M7	15M7	46	10-Oct-18	0702	EXPERIENCING VOLTAGE DIPS	MULTIPLE A/RS ON 15M7	2 CABLE POLE TERMINATORS FAILED AT 15M7 RISER OUTSIDE ESSEX TS	VOLTAGE DIP FELT AT ESSEX TS FELT BY MET HOSPITAL (15M5)	COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP
15M7	15M7	47	10-Oct-18	0702	CUSTOMER REPORTS VOLTAGE DIP	MULTIPLE 15M7 A/RS	2 CABLE POLE TERMINATORS FAILED AT 15M7 RISER OUTSIDE ESSEX TS	VOLTAGE DIP FELT AT ESSEX TS FELT BY CASINO (15M6)	COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP
15M6	15M6	48	29-Oct-18	1059	MOMENTARY OUTAGE , GEN FORCED OFF LINE	15M6 A/R	FOUND DEAD SQUIRREL AT POLE ON TEC AT TURNER		ANIMAL CONTACT
23M6		49	06-Nov-18	1236	FLICKERING LIGHTS	NIL	PATROLLED 23M6 - NOTHING FOUND	HIGH AMP ALARM RECEIVED ON SCADA, NO DEVICE OR BREAKER OPERATION [ENWIN OR H1] ASSOCIATED WITH THE ALARM. FEEDER PATROLLED REGARDLESS, NO CAUSE FOUND.	CAUSE UNKNOWN
15M6	15M7	50	03-Dec-18	2109	VOLTAGE DIP	15M7 A/R	DEFECTIVE SWITCH AT 15M7-DS-NW15 CAPDS'S CAUSED A/R	VOLTAGE DIP FELT AT ESSEX TS FELT BY CUSTOMER (15M6)	COMMON BUS VOLTAGE DIP - ENWIN FEEDER TRIP

2 - AMPCO - 16

Reference:

Exhibit 2: Rate Base Attachment 2-A P45 Table 9

Question:

Please provide the worst performing feeders for the years between 2016 to 2018.

Response:

Table 9 has been updated below to include the 2016-2018 data.

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
2016-2018	56M8 56M1 55M22 55M25 25M7 56M7 55M21 23M2 24M3 4M2

2 - AMPCO - 17

Reference:

Exhibit 2: Rate Base Attachment 2-A P50

Question:

Please provide the number of Crew Visits and Opportunities for Improvement in 2018.

Response:

In 2018, 1,245 Crew Visits were completed and documented inclusive of 410 Opportunities for Improvement.

2 - AMPCO - 18

Reference:

Exhibit 2: Rate Base Attachment 2-A P52

Question:

Please provide the total number of outages for each of the years 2008 to 2018.

Response:

Please see the requested information in the table below:

Year	# of Outages
2008	1081
2009	806
2010	924
2011	900
2012	797
2013	1003
2014	921
2015	845
2016	929
2017	893
2018	1101

2 - AMPCO - 19

Reference:

Exhibit 2: Rate Base Attachment 2-A P56

Question:

Please provide the SAIFI values for each of the years 2008 to 2018 excluding Major Events Days, Loss of Supply and Scheduled Outages.

Response:

The table below shows adjusted SAIFI excluding Major Event Days, Loss of Supply and Scheduled Outages. Historical data was queried to populate the table and the provided information is based on the best available information from ENWIN's records.

Year	SAIFI ADJUSTED
2008	2.3918
2009	0.9612
2010	1.6728
2011	2.1068
2012	1.5631
2013	1.8598
2014	1.6006
2015	1.6576
2016	1.1971
2017	1.5023
2018	1.9645

2 - AMPCO - 20

Reference:

Exhibit 2: Rate Base Attachment 2-A P57

Question:

Please provide the SAIDI values for each of the years 2008 to 2018 excluding Major Events Days, Loss of Supply and Scheduled Outages.

Response:

The table below shows adjusted SAIDI excluding Major Event Days, Loss of Supply and Scheduled Outages. Historical data was queried to populate the table and the provided information is based on the best available information from ENWIN's records.

Year	SAIDI ADJUSTED
2008	1.0321
2009	0.3780
2010	0.8543
2011	0.9040
2012	0.5071
2013	0.5183
2014	0.5740
2015	0.7984
2016	0.3580
2017	0.5106
2018	0.8112

2 - AMPCO - 21

Reference:

Exhibit 2: Rate Base Attachment 2-A P58

Question:

Please provide the total number of momentary outages for each of the years 2008 to 2018.

Response:

Please see the requested information in the table below:

Year	# of Momentary Outages
2008	263
2009	254
2010	221
2011	262
2012	206
2013	237
2014	243
2015	211
2016	143
2017	187
2018	212

2 - AMPCO - 22

Reference:

Exhibit 2: Rate Base Attachment 2-A P60

Question:

Please complete the following table:

Defective Equipment	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
% Contribution to SAIFI										
% Contribution to SAIDI										

Response:

The table below shows the percent contribution to SAIFI and SAIDI due to defective equipment. In following with the content of the responses to AMPCO-19 and AMPCO-20, loss of supply and major event days were omitted from the calculations.

Defective Equipment	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
% Contribution to SAIFI	20.4%	22.6%	24.4%	11.8%	29.8%	28.1%	31.7%	17.9%	13.9%	30.4%
% Contribution to SAIDI	30.1%	27.2%	28.9%	19.7%	24.6%	19.4%	22.6%	16.2%	31.0%	24.7%

2 - AMPCO - 23

Reference:

Exhibit 2: Rate Base Attachment 2-A P64

Question:

a) With respect to SAIFI, for each of the years 2013 to 2018, please provide a breakdown of the causes of defective equipment.
b) With respect to SAIDI, for each of the years 2013 to 2018, please provide a breakdown of the causes of defective equipment.

Response:

a) The table below shows the percent contribution of defective equipment to SAIFI by equipment type.

Defective Equipment	2013	2014	2015	2016	2017	2018
OH Transformer	7.2%	3.0%	8.5%	0.6%	0.3%	5.8%
UG Transformer	3.5%	2.0%	2.0%	4.5%	2.4%	4.5%
OH Switch	0.2%	1.9%	6.5%	1.7%	1.4%	2.8%
UG Switch	2.1%	0.3%	2.1%	0.9%	0.2%	0.1%
UG Cable	11.3%	6.0%	9.5%	9.9%	6.0%	6.2%
Connections	2.7%	1.6%	0.1%	0.1%	3.3%	0.1%
OH Conductor	2.1%	3.8%	2.5%	0.1%	0.1%	6.9%
Station Equipment	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Pole	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
Other	0.7%	9.6%	0.5%	0.1%	0.1%	3.7%
Total	29.8%	28.1%	31.7%	17.9%	13.9%	30.4%

b) The table below shows the percent contribution defective equipment contributed to SAIDI by equipment type.

Defective Equipment	2013	2014	2015	2016	2017	2018
OH Transformer	2.7%	1.8%	4.7%	3.1%	2.0%	4.3%
UG Transformer	6.3%	3.5%	2.3%	8.3%	6.4%	2.9%
OH Switch	0.7%	1.2%	3.9%	1.4%	11.0%	2.5%
UG Switch	1.0%	0.2%	0.7%	0.2%	0.5%	0.0%
UG Cable	6.6%	5.3%	8.6%	2.7%	6.0%	4.9%
Connections	3.0%	0.4%	0.1%	0.1%	4.0%	0.1%
OH Conductor	4.2%	4.4%	2.1%	0.1%	0.9%	1.1%
Station Equipment	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Pole	0.0%	0.0%	0.1%	0.1%	0.0%	2.5%
Other	0.1%	2.6%	0.1%	0.1%	0.2%	6.3%
Total	24.6%	19.4%	22.6%	16.2%	31.0%	24.7%

The tables above show the percent contribution to SAIFI and SAIDI due to defective equipment by equipment type. In following with the content of the responses to AMPCO-19 and AMPCO-20, loss of supply and major event days were omitted from the calculations.

2 - AMPCO - 24

Reference:

Exhibit 2: Rate Base Attachment 2-A P64

Question:

a) Please provide the calculation of the 3.07% and 1.67%.
b) Please provide the outage statistic result for 2018.
c) Please explain how the target of 5% was derived.

Response:

a) Please see the table below:

Year	Outages >1000 customers and >5 minutes (A)	Total Outages (B)	Statistic (A/B)*100
2016	33	1074	3.07%
2017	18	1081	1.67%

b) Please see the table below:

Year	Outages >1000 customers and >5 minutes (A)	Total Outages (B)	Statistic (A/B)*100
2018	34	1316	2.58%

c) The 5% target was chosen by consensus based on the size of ENWIN's feeders as well what ENWIN determined to be an outage of substantial length. An in depth statistical analysis was not conducted to come up with this figure.

2 - AMPCO - 25

Reference:

Exhibit 2: Rate Base Attachment 2-A P67

Question:

For each of the Program/Projects listed in Table 21, please identify the Program/Projects that are new since 2009 and provide the year they were initiated and why.

Response:

Program/Project Name	Year Initiated	Reasons Why
Feeder Reliability Improvement	2011	To address the issue of insufficient capacity to support a loss of one supply station to the ENWIN distribution system. The program is to build a high capacity ring feeder between Windsor's major supply stations. The ring feeder will be capable of moving sufficient power in the case of a loss of any station so that all feeders would have sufficient supply during peak load times.
Feeder Tie	2013	The opportunity to build automated feeder ties arised from ENWIN's prior expenditures on sectionalizing reclosers and switches. The feeder ties provide ENWIN the opportunity to transfer load quickly in the event of contingencies such as the need to off-load a feeder for maintenance work or in the event of an issue at the Hydro One supply station. The overall plan is for ENWIN to be able to sectionalize feeders in thirds and to provide adequate cross ties so that power may be restored to customers that are unaffected by the faulted section of the feeder.
Radial Branch Backups	2016	This program is intended to improve reliability for customers. A radial branch is a feeder section that does not have connectivity to feed from downstream by another source. The goal of this program is to ensure that large pockets of customers have dual feeds so that in the event of an upset, at least some, if not all, of those customers can be restored quickly. ENWIN's standard is that there should be a maximum of 500 customers on a single ended feed.

2 - AMPCO - 26

Reference:

Exhibit 2: Rate Base

Question:

Please provide the percentage of the capital budget undertaken by external resources for the years 2009 to 2018.

Response:

Please see the requested information in the table below. Please note ENWIN does not systematically track this information and does not have data available prior to 2011. The information provided in the table below was manually extracted based on the total cost of outsourced work contracted each year in comparison with the total amount of actual expenses incurred. The increase in 2014 was due to the Winsor Essex Parkway project.

Year	Percentage of external resources
2011	20
2012	19
2013	24
2014	32
2015	18
2016	9
2017	27
2018	11

2 - AMPCO - 27

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix 2-AA

Question:

a) Line 30 - Please separate the planned and reactive transformer investment costs for each year.
b) Line 40 Conductor Upgrades – The 2020 budget reflects $200,000 whereas the Conductor Upgrade Project – 23M2 LTP1 at Appendix F reflects $350,000 in 2020. Please reconcile.

Response:

a) Please see the table below:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test Year	2021 Forecast Year	2022 Forecast Year	2023 Forecast Year	2024 Forecast Year
Total # Transformers Replaced	183	249	270	261	210	260	214	167	194	N/A	N/A	N/A	N/A	N/A	N/A
# Transformers Reactive Basis	N/A	N/A	N/A	N/A	N/A	38	38	41	40	N/A	N/A	N/A	N/A	N/A	N/A

Note: The total numbers of transformers above includes new transformers and replaced transformers under System Renewal (planned and reactive). The number of transformers replaced on a reactive basis since 2015 were manually extracted from ENWIN's records. ENWIN does not have records of transformers replaced on a planned basis versus reactive basis prior to 2015.

b) Line 40 of the 2020 budget reflects only one of the projects planned for execution under the Conductor Upgrade program for the year. The Conductor Upgrade Project – 23M2 LTP1 is a conductor upgrade project that is planned to be done in conjunction with the replacement of poles at end of life with a small incremental cost (around 3%) for the larger conductors required for the implementation of a high capacity feeder.

2 - AMPCO - 28

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix 2-AA

Question:

a) Line 28 27.6 kV Pole Replacements – Please provide the number of poles replaced for each of the years 2009 to 2018 and forecast for 2019 and 2020.
b) Line 29 Planned Cable Replacements – Please provide the metres of cable replaced for each of the years 2009 to 2018 and forecast for 2019 and 2020.
c) Line 30 Planned & Reactive Transformers – Please provide the number of transformers replaced on a planned basis compared to a reactive basis for each of the years 2009 to 2018 and forecast for 2019 and 2020.
d) Line 31 – Reactive Pole Replacements: Please provide the number of poles replaced on a reactive basis for each of the years 2009 to 2018 and forecast for 2019 and 2020.
e) Line 32 Reactive Equipment Replacements – Please explain how the Reactive Equipment Replacements 2020 budget was derived.
f) Line 34 Manhole Rebuilds – Please provide the number of Manhole Rebuilds for each of the years 2009 to 2018 and forecast for 2019 and 2020.
g) Line 37 Other Renewal – Please explain how the Other Renewal 2020 budget was derived and provide a breakdown.
h) Line 48 Other - Please explain how the Other 2020 budget was derived and provide a breakdown.

Response:

a) Number of poles replaced:

	2010 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	491	1,234	1,062	1,271	830	765	426	470	675	500	544	544	544	544	544

Note: 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.

b) ENWIN has neither records of meters of cables replaced under this budget line nor the meters of cable planned for replacement for the forecast period (these are planned on a project cost basis, not by meters of cable).

c) Number of transformers:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test Year	2021 Forecast Year	2022 Forecast Year	2023 Forecast Year	2024 Forecast Year
Total # Transformers Replaced	183	249	270	261	210	260	214	167	194	N/A	N/A	N/A	N/A	N/A	N/A
# Transformers Reactive Basis	N/A	N/A	N/A	N/A	N/A	38	38	41	40	N/A	N/A	N/A	N/A	N/A	N/A

Note: The total numbers of transformers above includes new transformers and replaced transformers under System Renewal (planned and reactive). The number of transformers replaced on a reactive basis since 2015 were manually extracted from ENWIN's records. ENWIN does not have records of transformers replaced on a planned basis versus reactive basis prior to 2015.

d) Number of poles replaced on a reactive basis:

	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

Note: The table above shows the number of poles replaced on a reactive basis since 2015, manually extracted from ENWIN's records. ENWIN does not have records of poles replaced on a planned basis versus reactive basis prior to 2015.

e) The Reactive Equipment Replacements 2020 budget was derived from historical expenditure incurred with failed equipment and hardware.

f) The number of manhole rebuilds by year are as shown in the table below, including forecast for 2019 and 2020.

Year	Manhole Rebuilds
2009	10
2010	9
2011	15
2012	48
2013	24
2014	44
2015	7
2016	0
2017	2
2018	12
2019	6
2020	14

g) The "Other Renewal" budget amount was derived by addition of a number of different projects, the breakdown of which is shown in the table below.

Project	Capital Expenditure
Reactive Manhole Replacement	$ 20,000
Metering	$ 294,000
MIST Meter Population Replacement	$ 519,000
Walker Rd - Foster to Airport Rd	$ 750,000
Mischellaneous TS Equipment EOL Replacement	$ 75,000
Total	**$ 1,658,000**

h) The "Other" budget amount was derived by the addition of two separate projects, the breakdown of which is shown in the table below.

Project	Capital Expenditure
25M7 Feeder Ring	$ 380,000
Power Quality Improvements	$ 5,000
Total	**$ 385,000**

2 - AMPCO - 29

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix A

Preamble:

The Kinectrics report indicates the historic removal information was available for the asset groups that are outside stations and installed either overhead or underground, thus allowing build-up of their specific degradation curves.

Question:

a) Please explain why it is important to collect asset removal information and describe the type of information collected.
b) Please explain how historic removal information is used to derive specific degradation curves.

Response:

a) Removal information includes age of units at removal. This allowed the creation of probability density function indicating the percentage of units removed at each age. Since a good percentage of units outside stations are run to failure, the removal probability density function could be assumed to closely represent the probability failure function.

b) Rate of failure, also known as a hazard function (probability that a unit of a certain age will fail at that age) is directly related to the probability density function and is derived from it. The rate of failure is then combined with the age distribution to estimate how many units are expected to fail in a given year.

2 - AMPCO - 30

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix A

Question:

Please provide ENWIN's response to the recommendations listed on page vi and vii.

Response:

The following recommendation (*italicized type*) was an outgrowth of the completed ACA study. ENWIN has accordingly undertaken the collection of enhanced data in a number of the identified areas.

For the purpose of enhancing future ACA studies, it is recommended that EnWin improve data by collecting:

- *More age information for asset units of Station Switches, Overhead Switches (remote type) and Manholes;*

  All new assets, including "remote Overhead Switches" are subject to the Asset Installation and Removal process that itemizes the equipment, serial numbers and dates of installation (age) and removal, all of which are captured in both the GIS and SAP systems. Manholes are inspected and evaluated by an engineering firm however age data for manholes is generally not available.

- *Historic records of asset removal for the asset groups that are underground, and all the asset groups within stations;*

  All new Underground assets such as transformers and switch gear, are subject to the same Asset Installation and Removal process which houses records of all retired and installed pieces of equipment in the SAP system. Information related to equipment installed in transformer stations is also now captured in SAP but historic records related to these assets is incomplete.

- *Corrective maintenance records and inspection records, mainly for overhead and underground asset groups, as well as all the asset groups inside the stations;*

  Records related to equipment inspections for Overhead and Underground plant are captured in the SAP system but historical information on installation dates is unknown as is the exact age of many Underground cable lengths. Corrective maintenance information exists at the granular work order level but is not formally compiled nor analyzed at present.

- *Values of bushing power dissipation factor tests with temperature correction for Power Transformers and Station Breakers;*

  The above-noted values are currently determined for power transformers during scheduled preventive maintenance efforts. They are not presently recorded for breakers.

- *Manufacturer specification limits for contact resistance and operation cycles for Station Breakers;*

  Manufacturer specified contact resistance limits are observed and recorded during regularly scheduled breaker maintenance for the MTS stations. Operation cycles are not tracked at present.

- *Operation cycle counts, for both the normal operation and fault interruption for Station Breakers; and*

  Not presently tracked.

- *Fault records for UG Cables on segment level.*

  Not currently tracked.

Consideration is presently being given to whether or not and how data will be tracked for any of the presently outstanding recommendations.

2 - AMPCO - 31

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix A P6

Question:

a) Please list ENWIN's assets that have low consequences of failure.
b) Please list the assets that ENWIN runs to failure.

Response:

a) and b)

The following assets are considered to have low consequences of failure and/or a planned replacement would result in nearly the same level of inconvenience for customers, so ENWIN follows a "run to failure" philosophy for them:

- Residential padmount transformers (minipads);
- Three phase overhead transformer banks smaller than 150KVA;
- Single phase transformers (excluding submersible transformers); and
- Residential services

2 - AMPCO - 32

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix A P14

Question:

a) Page 14 - Please provide an excel version of Table 1.
b) Page 14 - For each of the assets listed in Table 1, please provide an excel table with the number of in-service failures for each of the years 2009 to 2018.
c) Page 15 – Please provide an excel version of Table 3.

Response:

a) An Excel version of Table 1 is attached. Please see AMPCO 32 – Attachment 1.

b) ENWIN does not track the number of in-service failures by asset category.

c) An Excel version of Table 3 is attached. Please see AMPCO 32 – Attachment 2.

2 - AMPCO - 33

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix A P17

Question:

a) For each of the assets listed in table 3, please provide the asset population and the number replaced for each of the years 2009 to 2018 in order to calculate an annual replacement rate.
b) Please provide an excel version of the table.

Response:

a) The asset population for each asset category is included in Exhibit 2: Rate Base, Attachment 2-A, Appendix A, Table 1. ENWIN does not track the number replaced each year.

b) The Excel version of the Table 3 has been provided in the response to AMPCO - 32.

2 - AMPCO - 34

Reference:

Exhibit 2: Rate Base Attachment 2-A Appendix B P3

Question:

Please provide the total number of Key Accounts.

Response:

ENWIN's consultant engaged with a total of 5 Key Account Customers who participated in the Validation Interviews.

4 - AMPCO - 35

Reference:

Exhibit 4: Operating Expenses Appendix 2-K

Question:

a) Please provide a version of 2-K that shows a breakdown of Executive, Management, Union, Non-Union and temporary FTEs.
b) Please provide incentive pay per year.
c) Please provide overtime costs per year.
d) Please provide the percentage of compensation costs that are capitalized for each year.
e) Please provide the total number of hours worked per year (excluding overtime).
f) Please provide the total number of overtime hours worked per year.
g) Please provide ENWIN's resource utilization rate for the years 2013 to 2018 and provide the calculation.
h) Please provide ENWIN's vehicle utilization rate for the years 2013 to 2018 and provide the calculation.

Response:

a) The allocation between Executive, Management, Union, Non-Union and temporary employees is not available in ENWIN's systems for the 11 years of data filed in the application.

b) The 2010 – 2018 actual incentive pay per year is summarized below. The 2009 payment information is not available within the current ERP/payroll system.

Year	Total Incentive Pay
2010	$ 310,953
2011	$ 271,344
2012	$ 238,620
2013	$ 247,712

2014	$ 273,667
2015	$ 268,777
2016	$ 272,193
2017	$ 284,695
2018	$ 270,321

c) ENWIN converted to a new ERP system and the detailed payroll data including benefits requested above is only available beginning in 2011. The chart below summarizes the overtime costs per year beginning in 2011 to 2018.

Year	Total Overtime ($)
2011	$ 615,250
2012	$ 535,649
2013	$ 762,528
2014	$ 1,231,327
2015	$ 1,071,982
2016	$ 1,206,110
2017	$ 853,006
2018	$ 1,182,745

d) The following table illustrates the percentage of compensation costs capitalized each year from 2010 actuals through the 2020 test year.

	Last Rebasing Year - 2009- Board Approved	Last Rebasing Year - 2009- Actual	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals
% of compensation costs capitalized vs total	25%	18%	17%	17%	14%	18%	18%

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
% of compensation costs capitalized vs total	18%	17%	15%	20%	18%	19%

e) The actual number hours worked by year excluding overtime is summarized in the table below. Please note that 2009 and 2010 hours were not available in the current ERP/payroll system.

Year	Total Hours Worked
2011	302,880
2012	311,223
2013	309,135
2014	308,258
2015	315,485
2016	324,186
2017	323,311
2018	313,856

f) As stated previously, data is only available at this detailed level beginning in 2011 as a result of a system conversion. The total overtime hours per year are included below:

Year	Total Overtime Hours
2011	9,329
2012	7,778
2013	10,913
2014	17,239
2015	14,724
2016	16,191
2017	11,182
2018	15,073

g) The following table shows ENWIN's resource utilization rate for the years 2013 to 2018 actuals. The calculation is based on productive compensation vs. total compensation. Non-productive compensation is defined as compensation for any time for the following: holidays, vacation, training (including safety, first aid, CPR), illness, doctor appointments, bereavement, inclement weather, union business, company business etc.

	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals
Resource Utilization Rate	77%	78%	78%	79%	78%	81%

h) The following table shows ENWIN's total weighted average vehicle utilization rate for 2018 is 76%. This calculation is based on total truck time entered on time sheets for class 5 (vans and pick-up), 6 (dump and utility) and 7 (bucket and line) vehicles, which make up the majority of ENWIN's fleet. The total truck time is compared to available time, which is defined as an 8-hour shift. Non-productive truck time would include idle time and time required for repairs and maintenance.

		2018						
		CL5	Utilisation	CL6	Utilisation	CL7	Utilisation	TOTAL
DEPT020	Hydro Admin	1	100%	N/A	N/A	N/A	N/A	
DEPT021	Control Room	1	20%	N/A	N/A	N/A	N/A	
DEPT022	Hydro Meter	4	81%	N/A	N/A	N/A	N/A	
DEPT024	SAM	2	64%	1	73%	2	78%	
DEPT025	Hydro Ops	13	74%	12	86%	17	88%	
	Total Units	**21**		**13**		**19**		53
	Average Utilisation		**68%**		**80%**		**83%**	76%

4 - AMPCO - 36

Reference:

Exhibit 4: Operating Expenses

Question:

Please provide the percentage of OM&A that is undertaken by external resources for each of the years 2009 to 2018 and forecast for 2019 and 2020.

Response:

Below is the percentage of external resources compared to OM&A for all years.

	2009 Last Rebasing Year Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Operations	$ 2,428,126	$ 2,179,670	$ 2,168,958	$ 2,215,696	$ 2,241,488	$ 2,446,148
Maintenance	$ 2,527,893	$ 2,574,239	$ 2,083,371	$ 1,941,200	$ 1,987,679	$ 2,014,312
SubTotal	**$ 4,956,019**	**$ 4,753,908**	**$ 4,252,329**	**$ 4,156,896**	**$ 4,229,167**	**$ 4,460,460**
Billing and Collecting	$ 1,265,826	$ 648,427	$ 1,277,901	$ 1,382,908	$ 1,215,699	$ 1,559,075
Community Relations	$ 39,117	$ 53,370	$ 106,603	$ 39,925	$ 48,192	$ 61,327
Administrative and General	$ 13,687,876	$ 16,002,774	$ 17,142,682	$ 20,836,210	$ 17,520,813	$ 18,998,119
SubTotal	**$ 14,992,819**	**$ 16,704,571**	**$ 18,527,186**	**$ 22,259,043**	**$ 18,784,704**	**$ 20,618,521**
Total	**$ 19,948,838**	**$ 21,458,480**	**$ 22,779,515**	**$ 26,415,939**	**$ 23,013,871**	**$ 25,078,981**
External Services	861,448	1,084,479	1,007,693	1,182,690	1,344,946	1,232,785
% of external resources to OM&A	**4%**	**5%**	**4%**	**4%**	**6%**	**5%**

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 2,648,198	$ 2,602,508	$ 7,269,859	$ 7,099,903	$ 7,698,671	$ 7,729,065
Maintenance	$ 1,750,044	$ 2,028,985	$ 2,487,236	$ 2,586,197	$ 3,243,162	$ 3,174,613
SubTotal	**$ 4,398,242**	**$ 4,631,493**	**$ 9,757,095**	**$ 9,686,100**	**$ 10,941,833**	**$ 10,903,678**
Billing and Collecting	$ 1,347,818	$ 1,618,089	$ 2,472,105	$ 2,625,277	$ 3,049,494	$ 3,122,687
Community Relations	$ 48,725	$ 55,286	$ 132,385	$ 147,723	$ 182,709	$ 147,723
Administrative and General	$ 19,598,340	$ 19,803,284	$ 14,396,981	$ 14,073,749	$ 14,599,324	$ 15,173,728
SubTotal	**$ 20,994,883**	**$ 21,476,660**	**$ 17,001,471**	**$ 16,846,749**	**$ 17,831,527**	**$ 18,444,138**
Total	**$ 25,393,125**	**$ 26,108,153**	**$ 26,758,566**	**$ 26,532,849**	**$ 28,773,361**	**$ 29,347,816**
External Services	1,315,560	1,467,476	998,783	1,350,628	1,435,056	1,246,638
% of external resources to OM&A	**5%**	**6%**	**4%**	**5%**	**5%**	**4%**

4 - AMPCO - 37

Reference:

Exhibit 4: Operating Expenses Appendix 2-JB

Question:

a) Please provide a breakdown of Professional Fees and Consulting costs for 2018 and 2020.
b) Please provide a breakdown of Outside Services in 2020.
c) Please provide a breakdown of Other Material Items in 2020.

Response:

a) Below is a breakdown of Professional Fees and Consulting for 2018 and 2020. ENWIN has provided 2018 actuals to be consistent with the updated Chapter 2 Appendices.

ENWIN Utilities Ltd.

Legal & Professional Details	2018 Actuals	2020 Test Year
Legal Fees		
Corporate & Commercial		
Wireless attachment	1,075	-
Active litigation	55,030	50,000
External Service contract agreement review	625	5,000
Engineering agreement review	1,607	7,000
Connection agreement review	2,469	2,853
Community support initiatives, corporate documents	3,197	52,751
Amendment to bank agreement, leases	7,722	-
Sofware/hardware contract reviews	34,780	22,777
Easements	610	-
Bank credit agreements, audit responses	10,425	1,113
Procurement contract reviews	9,947	8,866
Studies & Appraisals building consolidation	10,966	-
Disclosure of prior tenant utility usage info.	764	1,391
Employment / Labour grievances, general	18,995	28,408
Corporate governance issues, OEB proceedings	7,500	56,000
Total Legal	$ 165,711	$ 236,158
Professional & Consulting Fees		
Executive / Governance		
Strategic Planning / Provisional Consulting	1,950	68,179
Debenture retainer fee	3,312	-
Executive/Governance Consulting	22,532	15,267
Studies & Appraisals building consolidation	2,230	-
Human Resources		
Pay Equity	104	6,818
EAP	6,766	9,682
WSIB Consultant	1,998	5,693
Benefits Consultant	13,261	24,713
Miscellaneous	-	3,409
Finance / IT / Regulatory		
Regulatory Studies/Reassessments	1,302	27,600
Cost of Service	-	185,202
Actuarial Fees	8,872	-
Audit Fees/Tax Consulting	59,850	66,758
Internal Audits	31,987	29,750
Technical consultation	111,897	144,282
Operations		
ISO/ESA Audits	2,029	29,500
Asset Management Fees	5,653	2,165
H&S External Audit	-	15,430
Business Study Reviews	15,663	-
Easements	326	
Total Professional & Consulting	$ 289,732	$ 634,450

b) Below is a breakdown of Outside Services in 2020 in relation to Appendix 2-JB.

Program	**Service**	**2020 Test Year**
Station an MTS Maintenance	circuit switches at MTS	39,200
	fence maintenance	550
	Hydro One - Walker II - Rental fee	8,475
	lawn Care/weed control	8,858
	waterproofing maintenance, flashing, caulking	1,000
	oil sample testing	3,511
	painting of buildings	5,100
	roof inspection	4,590
	snow removal/salt application	30,373
	station transformer corrosion resistance	40,000
	structure relays, transformers, breakers	9,690
	utility Water bills	1,667
Storms	tree trimming/brush calls	11,040
	pole vacuum service	735
Tree trimming	tree trimming Area B/C area 1	245,472
	tree trimming Area B/C area 2	220,625
	annual tree trimming	78,832
Overhead Operations and Maintenance	concrete pole patching approx. 300 to 400 poles to repair	20,000
	pole painting perservative application	5,000
	easements/licence fees	1,806
	miscellaneous general maintenance	4,548
	Hydro One Joint use pole agreement	4,776
	encroachment/poleline rent	4,669
	utility occupations wire/pipe crossing	751

Underground Operations and Maintenance	defective/faulted service	52,625
	cold spray SU's to address the rust	27,523
	UG PMH cleaning	18,639
	jumper installation	2,592
	contracted civil work	13,009
	miscellaneous general maintenance	21,446
	UG locates	152,194
	GIS map upgrades	7,589
	cable chamber inspections	20,910
	UG locates assessed notifications	20,662
	pro-active high voltage cable testing	20,000
	wireless services, cellular/internet modem cost	7,785
	faulted indicators curcuit	6,120
Meter Operations	external services assisting with meter maintenance due to transformer station capital project.	120,000
Engineering	temporary contract services	4,276
Total Services		**1,246,639**

c) Below is a breakdown of Material Items in 2020 which amounts to $158,538.

Breakdown of Material Items 2020 totaling $158,538
various cable, plugs
bar code tags
cable sealing kit, loadbreak elbow
connectors, tape, screws, garbage bags
control box scadamate, main PC board
deadend connectors
disconnect sleeves
fuses, terminator cable, bushings
heat shrink tube
jumper, bolts, full tension sleeve, clamps
lighting arrester
locator marker flags, marking paint
meter base seal ring
painting materials
poly rope
rubbing alcohol, batteries
tissue wipes/wiping cloths
transformer oil drums

4 - AMPCO - 38

Reference:

Exhibit 4: Operating Expenses

Question:

Please provide the number of vacancies per month for 2018 and forecast for 2019.

Response:

The number of vacancies per month for 2018 are shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Vacancies	2	1	2	2	2	2	5	6	9	11	12	14

The 2019 forecast does not antipicate any vacancies.

4 - AMPCO – 39

Reference:

Exhibit 4: Operating Expenses

Question:

Please provide the number of retirements for the years 2013 to 2018.

Response:

The number of retirements for the Electric LDC for the years 2013 to 2018 are outlined in the table below:

Year	# of Retirements
2013	4
2014	2
2015	-
2016	2
2017	5
2018	5

7 - AMPCO – 40

Reference:

Exhibit 7: Cost Allocation P4

Preamble:

ENWIN indicates the proposed elimination of the Large Use – Ford Annex rate class will result in the movement of the sole customer in this class to the Large Use – 3TS rate class. This elimination allows ENWIN to align its remaining three Large Use customers served by dedicated transformer stations into a single consistent rate class.

Question:

a) Please provide a description of the drivers to eliminate the Large Use – Ford Annex rate class.
b) Please outline all discussions ENWIN has had with the Large Use – Ford Annex customer regarding the elimination of the Large Use – Ford Annex rate class.
c) Please provide copies of all correspondence between ENWIN and the Large Use – Ford Annex customer regarding the elimination of the Large Use – Ford Annex rate class.
d) Please confirm the Large Use – Ford Annex customer is in full agreement with ENWIN's proposal to eliminate the Large Use – Ford Annex rate class.
e) Please provide a status quo 2020 cost allocation model before the elimination of the Large Use – Ford Annex rate class and the movement of the sole customer in this class to the Large Use – 3TS rate class.
f) Please provide the cost allocated in the 2020 Study in part 9 e) to each rate class
g) Please provide the proposed monthly rates for the Large Use – Ford Annex rate class before and after implementation of the change.

Response:

a) to d):

In 2001, ENWIN and Ford Motor Company entered into a Transformer Station Service Agreement ("TSSA"), such that ENWIN would own, operate and maintain a 30 MVA dedicated transformer station to service the Ford Annex facility. The fees agreed to between the parties at that time were contractual, and structured on a fully fixed basis. This agreement was the impetus to create a separate and distinct customer class for Ford Annex.

Subsequently, in 2006[1], the OEB set aside the contract fees being charged by ENWIN to Ford as they were not cost based. Despite this, the rates that ENWIN charges to Ford Annex continue to be on a fully fixed basis.

The TSSA naturally expired in 2016, and ENWIN communicated with Ford their options for the transformer station pursuant to the agreement. Ford opted to terminate the TSSA with ENWIN effective November 30, 2016.

Excerpts from the October, 2016 letter:

> "Ford currently pays, and EnWin is obligated to charge, rates based upon the rate order issued by the Ontario Energy Board. Rates are set by the Ontario Energy Board following a public hearing which has traditionally involved intervenors acting on behalf of various ratepayer groups responding to an application by EnWin. Ford could participate in such a hearing in the future to ensure its perspective is considered by the Ontario Energy Board."
>
> "Given the authority of the Ontario Energy Board and the nature of the hearing process, EnWin cannot guarantee the amount or precise structure of a rate that can be charged to Ford – only that EnWin will charge Ford in accordance with any applicable rate order. A typical rate hearing takes approximately 8 months from the time of the application to receive a decision."

Ford was a registered intervenor in ENWIN's last rebasing application (EB-2008-0227). Pursuant to the Letter of Direction received by the OEB in this proceeding, ENWIN served notice of its application on Ford Motor Company. Ford did not intervene in ENWIN's current application.

It is ENWIN's position that the characteristics of Ford Annex are similar to the other two customers in its Large Use – 3TS rate class – such that all customers are served by dedicated transformer stations, and all have direct allocation of these costs. It is also appropriate that Ford Annex adopt the rate design of the Large Use – 3TS class, in that the class revenue is derived from a combination of fixed and volumetric rates, instead of a fully fixed rate structure.

[1] Reference EB-2005-0359.

As such, ENWIN is making an application to consolidate the three customers into one consistent rate class. ENWIN has filed in confidence correspondence with Ford as referenced in Attachment 1 to 3 of this response.

ENWIN's Key Accounts Supervisor has contacted Ford and requested a letter of support for ENWIN's proposal. ENWIN will provide a copy of Ford's response to its request.

e) and f):

Estimated costs allocated to each class prior to class consolidation:

	1	2	3	4	5	6	7	8	9	12
Total	Residential	GS <50	GS>50 - 50-4,999 KW Regular	GS>50 - 3,000-4,999 KW Intermediate	Large Use - 3TS	Large Use - Regular	Street Light	Sentinel	Unmetered Scattered Load	Large Use - Ford Annex
$57,416,792	$30,663,278	$5,548,615	$13,328,029	$357,886	$2,417,844	$1,786,393	$1,447,184	$86,725	$118,082	$1,662,756

Costs allocated to each class after class consolidation:

	1	2	3	5	6	7	8	9
Total	Residential	GS <50	GS>50 - 50-4,999 KW Regular	Large Use - 3TS	Large Use - Regular	Street Light	Sentinel	Unmetered Scattered Load
$57,416,792	$30,697,722	$5,559,372	$13,620,757	$4,080,600	$1,805,832	$1,447,699	$86,726	$118,083

ENWIN has filed an updated Cost Allocation Model with its interrogatory responses.

g) Please see the attached tables below.

Estimated monthly rates:

LU – Ford Annex Rate Class (prior to class consolidation):

Distribution charges: $104,635.01
Total Bill: $635,096.17

Customer Class:	LARGE USE - FORD ANNEX SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	3,784,000 kWh
Demand	6,200 kW
Current Loss Factor	1.0045
Proposed/Approved Loss Factor	1.0045

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 109,654.73	1	$ 109,654.73	$ 115,062.79	1	$ 115,062.79	$ 5,408.06	4.93%
Distribution Volumetric Rate	$ -	6200	$ -	$ -	6200	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	-$ 0.1680	6200	$ (1,041.60)	-$ 1.6819	6200	$ (10,427.78)	$ (9,386.18)	901.13%
Sub-Total A (excluding pass through)			**$ 108,613.13**			**$ 104,635.01**	**$ (3,978.12)**	**-3.66%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.3646	6,200	$ 2,260.52	-$ 0.4795	6,200	$ (2,972.90)	$ (5,233.42)	-231.51%
CBR Class B Rate Riders	$ -	6,200	$ -	$ -	6,200	$ -	$ -	
GA Rate Riders	$ -	3,784,000	$ -	$ -	3,784,000	$ -	$ -	
Low Voltage Service Charge	$ -	6,200	$ -		6,200	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		6,200	$ -	$ -	6,200	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 110,873.65**			**$ 101,662.11**	**$ (9,211.54)**	**-8.31%**
RTSR - Network	$ 3.5270	6,200	$ 21,867.40	$ 3.6214	6,200	$ 22,452.68	$ 585.28	2.68%
RTSR - Connection and/or Line and Transformation Connection	$ 0.7426	6,200	$ 4,604.12	$ 0.7419	6,200	$ 4,599.78	$ (4.34)	-0.09%
Sub-Total C - Delivery (including Sub-Total B)			**$ 137,345.17**			**$ 128,714.57**	**$ (8,630.60)**	**-6.28%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	3,801,028	$ 12,923.50	$ 0.0034	3,801,028	$ 12,923.50	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	3,801,028	$ 1,900.51	$ 0.0005	3,801,028	$ 1,900.51	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	3,801,028	$ 418,493.18	$ 0.1101	3,801,028	$ 418,493.18	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 570,662.61**			**$ 562,032.01**	**$ (8,630.60)**	**-1.51%**
HST	13%		$ 74,186.14	13%		$ 73,064.16	$ (1,121.98)	-1.51%
Total Bill on Average IESO Wholesale Market Price			**$ 644,848.75**			**$ 635,096.17**	**$ (9,752.58)**	**-1.51%**

Large Use – 3TS Rate Class (after class consolidation):

Distribution charges: $55,395.56
Total Bill: $578,525.90

Customer Class:	LARGE USE - 3TS SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	3,784,000	kWh
Demand	6,200	kW
Current Loss Factor	1.0045	
Proposed/Approved Loss Factor	1.0045	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28,953.80	1	$ 28,953.80	$ 36,890.42	1	$ 36,890.42	$ 7,936.62	27.41%
Distribution Volumetric Rate	$ 2.9416	6200	$ 18,237.92	$ 3.5331	6200	$ 21,905.22	$ 3,667.30	20.11%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.2858	6200	$ 1,771.96	-$ 0.5484	6200	$ (3,400.08)	$ (5,172.04)	-291.88%
Sub-Total A (excluding pass through)			**$ 48,963.68**			**$ 55,395.56**	**$ 6,431.88**	**13.14%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.6817	6,200	$ (4,226.54)	-$ 0.6122	6,200	$ (3,795.64)	$ 430.90	-10.20%
CBR Class B Rate Riders	$ -	6,200	$ -	$ -	6,200	$ -	$ -	
GA Rate Riders	$ -	3,784,000	$ -	$ -	3,784,000	$ -	$ -	
Low Voltage Service Charge	$ -	6,200	$ -		6,200	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		6,200	$ -	$ -	6,200	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 44,737.14**			**$ 51,599.92**	**$ 6,862.78**	**15.34%**
RTSR - Network	$ 3.5270	6,200	$ 21,867.40	$ 3.6214	6,200	$ 22,452.68	$ 585.28	2.68%
RTSR - Connection and/or Line and Transformation Connection	$ 0.7426	6,200	$ 4,604.12	$ 0.7419	6,200	$ 4,599.78	$ (4.34)	-0.09%
Sub-Total C - Delivery (including Sub-Total B)			**$ 71,208.66**			**$ 78,652.38**	**$ 7,443.72**	**10.45%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	3,801,028	$ 12,923.50	$ 0.0034	3,801,028	$ 12,923.50	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	3,801,028	$ 1,900.51	$ 0.0005	3,801,028	$ 1,900.51	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	3,801,028	$ 418,493.18	$ 0.1101	3,801,028	$ 418,493.18	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 504,526.10**			**$ 511,969.82**	**$ 7,443.72**	**1.48%**
HST	13%		$ 65,588.39	13%		$ 66,556.08	$ 967.68	1.48%
Total Bill on Average IESO Wholesale Market Price			**$ 570,114.50**			**$ 578,525.90**	**$ 8,411.40**	**1.48%**

Filed in Confidence:

Attachment 1 – Letter from ENWIN to Ford Motor Company dated August 10, 2016;

Attachment 2 – Letter from ENWIN to Ford Motor Company dated October 31, 2016;

Attachment 3 – Letter from ENWIN to Ford Motor Company dated December 12, 2016.

7 - AMPCO – 41

Reference:

Exhibit 7: Cost Allocation P7

Question:

With respect to billing and collecting, please explain the work required to prepare a bill for a high volume customer (GS>50-4,999 kW and Large Use) compared to a residential customer.

Response:

The major differences between billing and collecting a high volume customer compared to a residential customer are:

1- The complexity of the rates for large use customers requires dedicated resources to manage and test rate changes, keep current on changing regulations and programs, and to have trained and knowledgeable staff to provide a single point of contact for large use customers.
2- Large use customers are billed on interval data. This requires unique software and services to interrogate these customer's meters to obtain meter reads, which is a significant fixed cost. Since the number of customers in these rate classes is small, the unit cost per customer is higher than for residential or small commercial customers.
3- ENWIN is obligated to provide a consumption report to our customers. For interval metered customers, this requires ENWIN to print large consumption reports, intercept bills, and manually hand-stuff envelopes.

7 - AMPCO – 42

Reference:

Exhibit 7: Cost Allocation P9

Question:

ENWIN indicates it 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.

a) Please explain why ENWIN believes the load profiles have not materially changed between the classes.
b) Please explain the level of effort to update the load profiles at this time.

Response:

a) When Elenchus prepared the preliminary load forecast the load profiles were updated at that time as well. The load profile information is used in the cost allocation model to determine the demand allocators which allocate distribution costs related to demand. In the ENWIN Utilities 2020 cost allocation model the 4NCP allocator is the main demand allocator used. A review of the allocation percentages arising from the 4NCP allocators between the original load profiles and the updated version indicated there was a not a material difference between the two versions. As a result, ENWIN Utilities did not update the load profiles.

b) ENWIN estimates the total level of effort between internal and external resources to update the load profiles would be 3 to 4 weeks.

7 - AMPCO – 43

Reference:

Exhibit 7: Cost Allocation P9 Table 7-7

Question:

Please explain how the scaling factors used by rate class were derived.

Response:

In Table 7-7 the third column is titled "2004 Weather Normal Values used Information Filing (kWh)" and the fourth column is titled "2020 Weather Normal Values (kWh)". The information in the third column is the total of the hourly kW from the 2004 load profile for each rate class. This is the total 2004 weather normalized kWh for each rate class. The 2004 load profile was prepared by Hydro One and used in the 2006 Cost Allocation Information Filings prepared by ENWIN and filed in January 2007. The fourth column is the 2020 weather normalized value from the 2020 load forecast. The scaling factor is the result of column four divided by column three. The scaling factor is applied to each value in the 2004 load profile to determine the load profile for 2020. The 2020 load profile is then used in the 2020 cost allocation study.

7 - AMPCO – 44

Reference:

Exhibit 7: Cost Allocation P9 Table 7-8

Question:

a) Please provide the allocated cost to the Large Use – Ford Annex rate class from the 2009 Board Approved Cost Allocation Study.
b) Please provide the allocated cost to the Large Use – 3TS rate class from the 2009 Board Approved Cost Allocation Study.

Response:

a) The Large Use – Ford Annex rate class was allocated $1,361,628 of the service revenue requirement in EB-2008-0227.

b) The Large Use – 3TS rate class was allocated $2,364,786 of the service revenue requirement in EB-2008-0227.

7 - AMPCO – 45

Reference:

Exhibit 7: Cost Allocation P12

Question:

Please provide the revenue to cost ratio for the Large Use – Ford Annex rate class The Revenue to Cost ratios reflect the adjusted ratios as approved in EB-2010-0079.

Response:

The revenue to cost ratio from EB-2010-0079 for the Large Use – Ford Annex rate class was 94%.

8 - AMPCO – 46

Reference:

Exhibit 8: Rate Design P6

Question:

Please provide the approved Fixed/Variable Proportions for each rate class in EB-2010-0079.

Response:

The fixed/variable proportions from the EB-2010-0079 Final ENWIN RCRatio model are as follows:

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW
Residential	43%	57%	0%
General Service Less Than 50 kW	35%	65%	0%
General Service 50 to 4,999 kW	11%	0%	89%
General Service 3,000 to 4,999 kW	22%	0%	78%
Large Use - Regular	32%	0%	68%
Large Use - 3TS	36%	0%	64%
Large Use - Ford Annex	100%	0%	0%
Unmetered Scattered Load	100%	0%	0%
Sentinel Lighting	100%	0%	0%
Street Lighting	100%	0%	0%

8 - AMPCO – 47

Reference:

Exhibit 8: Rate Design P20

Question:

a) Please provide the distribution bill impacts by rate class excluding deferral and variance account disposition rate riders.
b) Please provide the distribution bill impacts (excluding rate riders) by rate class if the proposed elimination of the Large Use – Ford Annex rate class was not approved.

Response:

Please see the attached tables below. Note: the combined rates classes bill impacts tables are based on the versions of the Cost Allocation Model and Revenue Requirement Work Form filed as part of these interrogatory responses.

a) Distribution and bill impacts by rate class excluding rate riders (combined rate classes):

Customer Class	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill			
			Current 2019	Proposed 2020	$ Change	% Impact	Current 2019	Proposed 2020	$ Change	% Impact
Residential	750	-	$26.57	$28.15	$1.58	5.95%	$110.39	$111.69	$1.30	1.18%
General Service < 50 kW	2,000	-	$62.38	$63.47	$1.09	1.75%	$281.86	$282.07	$0.21	0.07%
General Service > 50 to 4,999 kW	65,000	200	$1,104.71	$1,169.17	$64.46	5.84%	$10,937.40	$10,970.03	$32.63	0.30%
Large Use 3TS	8,334,000	15,800	$75,431.08	$92,713.40	$17,282.32	22.91%	$1,239,883.86	$1,261,085.80	$21,201.94	1.71%
Large Use - Regular	4,323,000	7,900	$26,797.30	$30,721.58	$3,924.28	14.64%	$644,299.51	$649,552.55	$5,253.04	0.82%
Street Lighting	269,000	800	$73,938.67	$63,463.01	($10,475.66)	-14.17%	$123,165.01	$111,153.87	($12,011.14)	-9.75%
Sentinel Lighting	255	1	$25.18	$26.68	$1.50	5.96%	$58.99	$60.59	$1.60	2.71%
Unmetered Scattered Load	6,100	-	$252.31	$267.26	$14.95	5.93%	$992.74	$1,006.56	$13.82	1.39%

b) Estimated distribution and bill impacts by rate class excluding rate riders if the proposed rate class consolidations proposed in the Application were not approved (uncombined rate classes).

Customer Class	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill			
			Current 2019	Proposed 2020	$ Change	% Impact	Current 2019	Proposed 2020	$ Change	% Impact
Residential	750	-	$26.57	$27.88	$1.31	4.93%	$110.39	$111.41	$1.02	0.92%
General Service < 50 kW	2,000	-	$62.38	$62.01	($0.37)	-0.59%	$281.86	$280.53	($1.33)	-0.47%
General Service > 50 to 4,999 kW	65,000	200	$1,104.71	$1,206.87	$102.16	9.25%	$10,937.40	$11,012.63	$75.23	0.69%
General Service 3,000 to 4,999 kW	1,142,000	3600	$9,762.18	$10,168.54	$406.36	4.16%	$188,081.85	$181,446.13	($6,635.72)	-3.53%
Large Use 3TS	8,334,000	15,800	$75,431.08	$79,708.81	$4,277.73	5.67%	$1,239,883.86	$1,246,390.61	$6,506.75	0.52%
Large Use - Regular	4,323,000	7,900	$26,797.30	$30,441.44	$3,644.14	13.60%	$644,299.51	$649,236.00	$4,936.49	0.77%
Large Use - Ford Annex	3,784,000	6,200	$109,654.73	$115,062.79	$5,408.06	4.93%	$643,471.37	$650,238.94	$6,767.57	1.05%
Street Lighting	269,000	800	$73,938.67	$62,123.10	($11,815.57)	-15.98%	$123,165.01	$109,639.77	($13,525.24)	-10.98%
Sentinel Lighting	255	1	$25.18	$26.42	$1.24	4.92%	$58.99	$60.30	$1.31	2.22%
Unmetered Scattered Load	6,100	-	$252.31	$264.73	$12.42	4.92%	$992.74	$1,003.70	$10.96	1.10%