**SLHI – 2018 Rates (EB-2017-0073)**

**OEB Staff Questions**

As discussed, there is no expectation that updates be made directly to the application (including the supporting models) at this time. If SLHI agrees that it is appropriate to make an update to the application, please advise of that position. If SLHI does not believe an update to the application is warranted, please provide supporting rationale. For some of the questions where no updates to the application are implied, it is best if a comprehensive response can be provided in the written response.

**Detailed Questions – Email Only**

Administration (Exhibit 1)

1. **Exhibit 1, Page 63, Appendix 1H, 2016 Audited Financial Statements**

Note 4 of the financial statements shows that a $116k error in the calculation of depreciation has been corrected as a prior period statement. The error impacts capital assets and the IFRS transition costs and adjustments DVA. Please explain the error and whether this error has been reflected in the application for 2015 PP&E and the relevant DVA requested for disposition. If yes, please explain how it has been reflected in the application. If no, please explain. If necessary, please revise the evidence.

Response:

SLHI adopted a new Capitalization policy in 2012 to revise the useful lives of assets to align with IFRS, expecting to adopt IFRS in 2012, but did not adopt until Jan 1, 2015. In 2011, BDO developed asset continuity schedules to prepare for the transition to IFRS when it was expected that utilities would be required to adopt Jan 1, 2012. These continuity schedules were much more detailed and provided per unit costs in order to account for disposals of pooled assets (poles, conductor etc). Since this was postponed, SLHI continued using their own continuity schedules until the transition in 2014 for adoption in 2015.

When calculating depreciation and disposals for the transition to IFRS in 2015 (for 2014 and 2015) the BDO continuity schedules were used since accounting for disposals was now required. SLHI recorded a debit of $116 K in account 1575 for the difference between the depreciation calculated using SLHI continuity schedules and the BDO continuity schedules. Since SLHI adopted the new useful lives in 2012 the amount should not have been material. Upon further review, it was discovered that the issue was in the way in which the continuity schedules calculated the remaining useful lives. It was not consistent with the method used in 2012. The BDO schedules were calculating the remaining useful lives on specific detailed assets in the continuity schedules (not NBV). Rate regulated utilities are allowed to utilize a deemed cost exemption, using the carrying amounts equal to previous CGAAP (OEB Accounting Procedures Handbook, Article 510, page 12) and apply IFRS on a prospective basis. Therefore the BDO continuity schedules were revised to calculate the remaining useful lives on the NBV as of Jan 1, 2012, when SLHI adopted the new capitalization policy, reducing the difference between what was recorded for depreciation under CGAPP and IFRS. The change affected the depreciation charged and the disposal value of assets.

Yes the error has been reflected in the 2015 PP&E and account 1575. The revised continuity schedules were used in the Chapter 2 appendices and account 1575.

1. **Exhibit 1, Page 64, Appendix I, Reconciliation between Audited Financial Statements and Regulatory Results**

In the 2016 reconciliation,

1. Accumulated amortization includes a note “add back $97k for Account 1576” and a corresponding note to adjust retained earnings. Please explain what this means and how the Account 1576 balance would have impacted accumulated amortization and retained earnings based on the accounting guidance for this account provided in the APH and APH FAQs. Please explain whether this adjustment has been reflected in the application and where it has been reflected.

Response:

SLHI recorded the amount in account 1576 for regulatory purposes only. Therefore it was not reflected in the audited financial statements. This required an adjustment to filing 2.1.7 each year since 2013. The amount of $97K was approved for disposition in the 2013 COS application. The impact to accumulated depreciation was an increase of $24 K over four years beginning in 2013 and an initial decrease to retained earnings in 2012 of $97K, then a reduction to this amount over four years for $25 K. The entries are provided below:



These adjustments are reflected in the Appendix 2-BA asset continuity schedules under fully allocated depreciation.

1. Sale of electricity and cost of power in the RRR equal $8,628,547. In the financial statements, electricity sales is $11,786,177 and purchased power is $9,740,269. Please reconcile the sale of electricity and cost of power between the RRR and the financial statements to ensure that no profit or loss is made on the commodity.

Response:

No profit or loss was made in commodity. The financial statement presentation of electricity sales includes distribution revenue (except for the street lights as they are presented separately), as well as the add back of revenue recorded to reduce cost of power income to record net regulatory movement in account balances separately. This is also done in the Power purchased. See reconciliation below:



The net movement in regulatory account balances is recorded as a reduction to net income on the statement of operations of $285,472 ($1,398,045 - $1,112,573), and the balance is distribution revenue.

1. **Benchmarking Model**

Please file the updated benchmarking model for 2018 filers. Please ensure that the amounts for capital additions, load forecast and OM&A match the amounts included in evidence. Where there are variances, please explain.

Response:

The spreadsheet is attached. Reconciliation of the model vs. the evidence:



The sentinel light expenses should have been removed from the totals in the evidence for 2016 and 2017. However, they were not included in the Test Year expenses. I feel that the amount is immaterial to bother correcting since it is not included in the Test Year totals. Also, I couldn’t find the $1,350 difference in 2016, but feel it is immaterial as well.

Rate Base (Exhibit 2)

1. **Exhibit 2, Page 33**

It is stated that PP&E acquired prior to Jan. 1, 2012 are measured at deemed cost established on the transition date, less accumulated depreciation.

1. Does Sioux Lookout mean PP&E acquired prior to Jan 1, 2014, the transition date to IFRS are measured at deemed cost established on the transition date, less accumulated depreciation?

Response:

The wording in this statement should be revised to “…measured at deemed cost established on the adoption of the new useful lives less accumulated depreciation.” It was meant to refer to the adoption of the new capitalization policy in 2012.

1. If not, please explain if the measurement of PP&E has changed after Jan. 1, 2012, when Sioux Lookout changed its capitalization and depreciation policies. If yes, please explain how it has changed.

Response:

The measurement of PP&E has not changed since Jan 1, 2012.

1. **Exhibit 2, Page 42, Appendix 2C, Capitalization Policy**

In the Residual Value & Useful Life section of the capitalization policy, it states “Sioux Lookout Hydro Inc. will review at least annually the residual value and useful life of each asset. Reviews ensure that the carrying amount do not differ materially from what would be determined using fair value at the balance sheet date. Increases and decreases in capital assets during the reviews will be reported as a profit or loss in equity”. It appears that Sioux Lookout may not be using the historical acquisition cost in determining the PP&E values.

1. Please clarify whether this is the case.

Response:

We are using historical acquisition cost in determining PP&E values. There has not been a case where it was determined that the fair value would be materially different. Therefore this has not been used.

1. If yes, please explain whether historical acquisition cost has been used for ratemaking purposes in the calculation of PP&E as at December 31, 2018 in this application.

Response:

Acquisition cost has been used for ratemaking purposes in the calculation of PP&E for all years.

1. If not, please quantify the increases or decreases in PP&E from the acquisition cost and indicate where these increases or decreases have been included in the rate application.

Response:

N/A

1. Please provide plan vs. actual CAPEX variances for the years 2014-2016 in the same manner as was provided for 2013 (at Ex. 2 / p. 31).

Response:

I believe these variances are illustrated in Table 2-24 on page 27 of Exhibit 2 and on page 56 of Appendix 2A (DSP) Table 24, under 5.4.1.4 total Capital Cost.

Load Forecast (Exhibit 3)

1. The 2013 OEB-approved revenue for the GS > 50 kW rate class as set out in Appendix 2-IB does not match Table 3-1 ($304,779 vs. $299,949). Please reconcile.

Response:

The amount in Table 3-1 is $305,779. The difference is $5,830 for the transformer allowance (EB-2012-0165, DRO page 11). The gross revenue should be $305,779 in Appendix 2-IB.

1. 2013 OEB-approved weather normalized kWhs for the GS > 50kW rate class as set out in Appendix 2-IB does not seem correct. Please revise.

Response:

Yes this is an input error. The amount entered into cell O150 should be 23,046,182.

The Chapter 2 Appendices have been revised and attached.

OM&A (Exhibit 4)

1. In the RRWF, 2018 depreciation is $234,839, please confirm that this reflects the Chapter 2-BA depreciation expense of $291,686 net of fully allocated depreciation.

Response:

Yes, the amount in Appendix 2-BA of depreciation expense less fully allocated depreciation is $234,842. The $3 difference is due to rounding.

1. Table 4-4 at Ex. 4 / p. 7 does not exactly match the version of the table filed at Chapter 2-JB. Please reconcile.

Response:

This was an oversight error. Table 4-4 was not updated with the most recent version of Appendix 2-JB when the application was filed. Table 4-4 should be updated using the filed Appendix 2-JB.

1. **Exhibit 2, Page 14, Appendix 2-BA 2018**

**Exhibit 3, Page 29, Appendix 2-H**

**Exhibit 4, Page 38, Appendix 4-E, PILS Workform**

In Appendix 2-BA, 2018 disposals under net additions and accumulated depreciation show a net loss of $16k. In Appendix 2-H and the PILS Workform, 2018 loss on disposals is $2k. Please explain the difference and revise the evidence if necessary.

Response:

This is an error. Appendix 2-H and 4-E as well as the PILs workform will have to be updated to reflect the $16K.

1. **Exhibit 4, Page 16**

**Exhibit 4, Page 35, Appendix 4B, Post-Employment Benefit and Vested Sick Leave Projections for 2017 and 2018**

For pension and OPEBs,

1. Per page 33 of the Filing Requirements for 2018 Rate Applications, please provide the amount of pension and OPEB included in OM&A and capitalized from 2013 to 2018.

Response:



1. Please explain the 2018 gross OPEB amount included in the application if it is different than the $9k ($4k + $5k) projected in the actuarial report.

Response:

The gross amount included in the application is the same as projected in the actuarial report - $8,525 rounded to $9K.

1. **Exhibit 4, Page 28**

**Exhibit 2, Pages 8 to 14, Appendix 2-BA**

In Exhibit 4, Sioux Lookout indicated that it does not have any non-utility activities. In Appendix 2-BA, there are non-rate regulated utility assets that are excluded from the total PP&E. Please explain whether these non rate-regulated utility assets relate to non-utility activities and whether these assets have been excluded from the PILS calculation in determining CCA. If not, please exclude the non rate-regulated utility assets from the PILS calculation.

Response:

SLHI rents out sentinel lights to customers, this is recorded as rental in non-regulated activities and as such the assets are considered non-regulated.The PILs workform will have to be revised to remove these assets from the CCA Calculation for historical year, however the bridge year and test years are correct and do not include them.

Cost Allocation (Exhibit 7)

1. Sioux Lookout Hydro has a negative asset value, net of Accumulated Depreciation and Contributed Capital, for accounts: (a) 1860 – Meters, 1920 – Computer Equipment – Hardware; and (b) 1925 – Computer Software. Please review the gross asset, accumulated amortization, contributed capital, and amortization of contributed capital for all asset categories, and update as required.

Response:

This is a result of reclassifying amounts from these accounts to Account 1855 – Services, which SLHI does not separate out in their accounting. So the amounts on Sheet I4 will have to be revised to separate out the depreciation allocated to Account 1855 for cost allocation purposes. This will resolve the negative NBV.

1. On Sheet I6.2 Customer Data, all 53 GS > 50 customers are included as receiving Line Transformer and Secondary Distribution service. On Sheet I8 Demand Data, all GS > 50 Demand is included in the Line Transformer and Secondary NCP values. However, on Sheet I6.1 Revenue, a Transformer Ownership Allowance is applied to some billing demand. Please explain or correct the apparent inconsistency.

Response:

This is an error, Sheet I6.2 and Sheet I8 will have to be revised to include only the portion of GS > 50 Kw customers who receive the transformer credit.

Rate Design and Bill Impacts (Exhibit 8)

1. GS > 50 kW Line losses are missing from the bill impact model. Please include.
2. USL does not require a bill impact schedule as the rate class will no longer exist (based on the proposal). Please remove this bill impact schedule from the model.

Response:

The 2 items have been corrected and the model filed with these questions.

Deferral and Variance Accounts (Exhibit 9)

1. **Exhibit 9, Pages 9 to 10, Appendix 2-EA**

**Exhibit 2, Pages 9 to 13, Appendix 2-BA**

**Exhibit 9, DVA Continuity Schedule**

For Account 1575,

1. The closing net book value under CGAAP for 2014 and MIFRS for 2015 to 2017 in Appendix 2-EA do not match the net book value (under the sub-total line) in Appendix 2-BA. Please reconcile the differences and update the evidence if necessary.

Response:

The differences were due to amounts reported in the net depreciation under CGAAP, when they should have been reported under MIFRS for 2-EA. Appendix 2-BA is correct. The amounts have been revised in the Chapter 2 Appendix 2-EA and the small difference in the balances from 2-EA to 2-BA is due to rounding.

1. WACC is 5.74% per the RRWF. Please explain why 3.72% was used to determine the return in Account 1575 and revise Appendix 2-EA if necessary.

Response:

This is an error, the appendix has been updated with 5.74%.

1. In the DVA Continuity Schedule, the return on rate base associated with Account 1575 is excluded from the balance requested for disposition. As a result, the rate riders calculated in the DVA Continuity Schedule are different than that presented in Exhibit 9, page 10. Please revise the balance requested for disposition in the DVA Continuity Schedule to include the return on rate base.

Response:

The DVA Continuity schedule has been updated to include the return on rate base updated to 5.74% of $15,202. The amount was assumed to be interest, and these cells are greyed out in the model and you cannot enter data in them. That is the reason it was not included originally. Therefore the amount was added to the principle. The tables in Exhibit 9 will have to be updated with the new return as well, since the rate rider has changed with the change to WACC.

1. **Exhibit 9, Page 16**

Sioux Lookout indicated that it is a fully embedded distributor of Hydro One and is not charged the CBR. Therefore, it has no value recorded in Account 1580, Sub-account CBR Class B.

1. Please confirm that Hydro One has not included the CBR charge in its WMS charge applied to Sioux Lookout.
2. Per Sioux Lookout’s 2016 tariff of rates and charges, a WMS rate of $0.0036, including the CBR rate of $0.004 was charged. Therefore, a credit balance in the Account 1580, sub-account CBR Class B would have been expected if there was no corresponding CBR charged to Sioux Lookout. Please confirm whether this was the case and revise the DVA Continuity Schedule if necessary.

Response:

I guess this is an interpretation error. Looking at our invoices from Hydro One, they do charge us $0.0036. I would argue that since we charge the same rate, the differences would net out to almost zero since all of our customers are Class B. Any difference would be immaterial and relate only to line loss.

1. **Exhibit 9, Page 18**

**Exhibit 9, GA Analysis Workform**

In the description of Sioux Lookout’s settlement process, it states that Sioux Lookout performs monthly true ups. The actual billed consumption for RPP customers is extracted from the billing system for the previous month and netted against the estimate used at the time the settlement was sent to the host distributor.

1. Please confirm that the billing cycle is on a calendar month. If not, please describe the billing cycle.

Response:

Yes the billing cycle is on a calendar month.

1. Please confirm that the true up for December 2016 trues up consumption to the December 2016 load month consumption (i.e. not consumption that is billed in December but the December load month consumption).

Response:

Yes, the true up for December 2016 would be based on the December 2016 consumption which is billed in January.

1. If not, please clarify what consumption the estimated consumption is being trued up to.

Response:

n/a

1. **Exhibit 9, DVA Continuity Schedule**

Per the DVA Continuity Schedule instructions, step 1, for Account 1595 sub-accounts, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For Accounts 1595 (2014), this amounts should be inputted starting in 2014.

1. In the DVA Continuity Schedule, Account 1595 (2014) begins in the transactions column in 2015. Please input the relevant amounts starting in 2014, including the OEB approved disposition and transaction amounts.

Response:

The DVA Continuity schedule has been updated with the relevant amounts starting in 2014.

1. Please explain what the principal and interest adjustment for Account 1595 (2014) under 2015 is related to.

Response:

The principal and interest adjustment for Account 1595(2014) under 2015 was simply the opening balance on Jan 1, 2015. These amounts have been removed since they are now included in 2014.

1. The rate rider for Account 1595 (2014) is from May 1, 2014 to April 30, 2015. However, there are no transactions in the principal column under 2015. Please explain why and revise the DVA Continuity Schedule if necessary.

Response:

The schedule does not need to be revised. An amount of $44,617 is included in cell AT38 to record transactions in 2015.

1. **Exhibit 9, DVA Continuity Schedule**

In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approaches is used:

1. Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively;
2. Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equaling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equaling GA RPP is credited into Account 1589; or
3. Another approach. Please explain this approach in detail.

Response:

Since SLHI does not receive an invoice from the IESO, we do follow another approach. I’ve attached a copy of one of our Hydro One invoices which shows how the charges look. We get charged a line item for “Global Adjustment Volumetric” and “Electricity @ Spot Price”. The Electricity @ Spot price is booked to account 1588, and a portion of the Global Adjustment is booked to 1589. To determine the amount of Non-RPP GA paid to allocate to 1589, in this example, the Non-RPP and RPP kwh billed for October is taken from our revenue reports generated by our billing system. The Non-RPP kwh for October 2016 is 2,018,914 kwh. From the Hydro One invoice the kWhs (5,455,147.50) from the Global Adjustment line is entered into a spreadsheet and the Total GA $ paid (612,394.86). The per kwh price is determined by dividing 612,394.86/5,455,147.50 and then multiplying this to the Non-RPP kwh billed (2,018,914) to get the estimated Non-RPP GA paid to include in the 1589 variance calculation. The spreadsheet is included to illustrate the calculations titled ”correction of Non-RPP GA allocation.xlsx”.

Note: This process is a new process. It was changed after completing the GA Analysis workform and discovering we were not prorating the RPP and Non-RPP portion of the Ga paid properly, as there was a large variance when we completed the form. This is explained in Question 6 (b) as the principle adjustment of $314K in 2016 is a result of this.

1. **Exhibit 9, DVA Continuity Schedule**

**Exhibit 9, GA Analysis Workform**

With regards to the Dec. 31, 2016 balance in Account 1589,

1. Please indicate whether the following items that flow into the account are based on estimates or actuals at year end.
	1. Revenues (i.e. is unbilled revenues trued up);

Response: Actual unbilled revenue is included to December 31, 2016 with the exception of the Long Term Load Transfer unbilled revenue which is estimated for year-end since we do not perform the settlement until April the following year.

* 1. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount;

Response: Actual year end expense is used.

* 1. Expenses - GA non-RPP (Charge Type 148) with respect to RPP/non-RPP proration percentages; and

Response: Actual year end expense is used.

* 1. Credit of GA RPP (Charge Type 142) if the approach under previous IR is used.

Response: Yes the RPP GA is separated out from Non-RPP GA

1. In the DVA Continuity Schedule, there is a principal adjustment of $314k in 2016. Please explain what this adjustment is and how it relates to the $42k reconciling item 1b in the GA Analysis Workform.

Response:

After initially completing the GA Analysis workform there was a very large variance in the expected balance in Account 1589. It was discovered that the process to estimate the portion of GA to attribute to RPP and Non-RPP GA was not resulting in an accurate proration. The problem was that the portion of GA to attribute to RPP was being estimated on the GA billed to RPP customers (we track the amount that would have been billed to RPP customers and then apply an offsetting credit so there is no charge to the customer). The process was changed and the numbers revised for 2016 and 2017 only since the 2015 variance account 1589 was disposed of in our 2017 IRM (EB-2016-0103). I’ve attached a spreadsheet with the calculations of the new process, and the determination of the adjustment. Therefore there was an adjustment of a debit of $314k to account 1589 and a credit to account 1588 for the same amount.

The $42k reconciling item is related to the amount booked for unbilled Non-RPP GA Billed at year end related to our Long Term Load Transfer Settlement which was not completed until after our year-end audit, therefore the amount was estimated at $41,891.85, and the actual billed in April 2017 was $41,303.62. We performed our final settlement for the long term load transfers in October, therefore going forward there will be no estimates in the unbilled revenue at year-end.

1. **Exhibit 9, DVA Continuity Schedule**

With regards to the Dec. 31, 2016 balance in Account 1588:

1. Please indicate whether the following items that flow into the account are based on estimates/accruals or actuals at year end.
	* 1. Revenues (i.e. is unbilled revenues trued up);
		2. Expenses - Commodity (Charge Type 101);
		3. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount;
		4. Expenses - GA non-RPP (Charge Type 148) with respect to RPP/non-RPP proration percentages; and
		5. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type).

Responses are the same as for 6(a)

* 1. In the DVA Continuity Schedule, there is a principal adjustment of ($314k) in 2016. Please explain what this adjustment is for and how it was calculated.

Response:

See answer to 6(b)

1. **Exhibit 9, GA Analysis Workform**

In the GA Analysis Workform,

1. The net change in principal balance in the GL is ($78,160) for 2016, this should equate to the 2016 transactions in the DVA Continuity Schedule. However, the 2016 transactions in the DVA Continuity Schedule for Account 1589 is ($391,536). Please explain the difference and revise the GA Analysis Workform or DVA Continuity Schedule if necessary.

Response:

If you add the ($391,536) net change in principle to the principle adjustment of $314,140 it equals the net change in the GA workform of ($78,160). My spreadsheet has the principle adjustment calculated to be a credit of $313,376 to be applied to account 1588 and debited to 1589. I’ve determined the variance of $764 is interest related to the correction. However, don’t feel it is material enough to revise my RRR filings.

1. Reconciling item 1b is for the adjustment to “unbilled non-RPP customers for December in January”. On Exhibit 9, page 17, the adjustment is explained as the “December 2016 RPP settlement true up booked in January”. Please clarify whether the adjustment is a true up of unbilled revenues (reconciling item 2b) or for the RPP settlement true up.

Response:

I think I misinterpreted the items initially. The statement in Exhibit 9 page 16 is incorrect. It should be explained as in 6(b). It is for unbilled revenue estimated in December but not billed until April 2017 for the long term load settlement of $42K. The statement in the GA Analysis Workform should be revised as well to better explain the adjustment, and it should be shown in item 2b) not 1 b).

1. Please explain why reconciling item 1a does not apply and 1b does apply. Did Sioux Lookout’s RPP settlement process change from 2015 to 2016?

Response:

I believe the above explanation cover this. 1 a) and b) do not apply.

1. Please confirm that reconciling items 2 to 6 do not apply or are immaterial.

Response:

In the revised GA Analysis Workform, item 2 a) does not apply. Item 2 b) is explained above. Item 3 a) is the difference between the estimated and actual LTLT GA for 2015, and 3 b) is the difference between the estimated and actual LTLT GA for 2016.

**Conference Call – Follow-up**

During our conference call, we discussed that responses to the below questions / issues would support the application.

Administration (Exhibit 1)

1. Additional information regarding the linkage between low density service area and revenue requirement.

Response:

The revenue requirement reflects the costs associated with operating and maintaining a larger service territory (539 km2). The 2016 pole count was just over 2,700 poles and the customer count at the end of 2016 was 2,790. This is a ratio of almost 1:1. Fixed costs such as skilled workers and equipment needed to access some of our remote areas ( no road access, i.e. across a lake or heavily forested) are required to operate. Due to SLHI’s low customer number this results in higher OM&A per customer costs.

Comparing revenue per kwh delivered to other utilities with similar sized service territories SLHI falls within .02 to .04 cents of revenue per kWh delivered ( 2016 Yearbook of Electricity Distributors) at .03 cents. The OM&A expenses per customer are higher. However comparing the service territory size and the customer numbers to for example Energy+ Inc. with 562 km2 and 458 km2 of rural, or North Bay Hydro with 330 km2 and 279 km2 of rural, their customer numbers are much higher at 64,123 and 24,070 respectively, allowing them to spread out their fixed costs over a larger customer base.

Rate Base (Exhibit 2)

1. Update to cost of power calculation (and related documents) for working capital allowance proposal.

Response:

Spreadsheet attached with updated COP. Will update related documents once all the issues have been resolved in order to reduce the number of times everything is updated.

1. Historical Pole Replacement Overspend – explanation for overspend and confirmation as to whether “poor” condition poles were replaced (or were all poles specifically tested prior to replacement).

Response:

See table below:



The poles identified as “poor” in the ACA were tested prior to replacement and if it is determined that the life can be extended they are not replaced. (Ref page 82 of the DSP)

DSP & CAPEX (Exhibit 2)

1. Refurbish vs. Replace poles – Explain why refurbishment does not form part of plan.

Response:

See page 82 of the DSP. As stated refurbishing poles is rare, however there are instances where SLH uses pole extenders if warranted rather than replacing the entire pole. Also, woodpecker holes are often patched if the damage is not too severe. These costs would be reflected in the OM&A expenses.

1. Pole Replacement program – additional information on how capital spending is prioritized (based on testing or age information only).

Response:

We prioritize the spending on pole replacements on age and testing combined. We have all the age information therefore we perform additional testing with a pole testing drill prior to replacing. This is for planned replacements only. Line patrols are also performed as a part of our maintenance program and any obvious defects that are identified by visual inspection are dealt with immediately.

1. Pole-mount transformers – Confirm run-to-fail strategy is utilized and all capital spending in this category is for reactive replacement activities.

Response:

Yes the run-to-fail strategy is utilized for all capital spending in this category.

1. Underground cable – Advise whether underground cables in “fair” conditions are planned for replacement during forecast period. Additional information is needed to explain why underground cable is planned for replacement during forecast period.

Response:

Reference page 84 of the DSP and Appendix F of the Asset Management Plan (Appendix A of the DSP).

The cable testing results showed that the cables slated for replacement in 2019 are in “Fair” condition. Fair condition is described as “Failure due to water treeing is moderate and could increase and result in insulation failure if voltage transients due to switching operation or lightning surges are not properly controlled. Cable could be repaired and returned to service after failure. However, the cable should be retested every 3 to 5 years to keep track of the on-going water tree deterioration.” (Page 3 of the Underground cable test report) This testing was done in 2016. The cable identified as fair indicated that they were commissioned in the early 80’s making them 37 years old.

SLHI is approaching this in a proactive manner. Given the risk to the customers should the cable fail, especially if it should occur in the winter, and the age of the conductor,SLHI feels that it is essential to replace the cables within this time frame.

1. 2013 bucket truck replacement in 2020 – Additional rationale required with respect to the need to replace a bucket truck that will be 7 years old in 2020. Detailed breakdown regarding annual maintenance costs in the recent years and 2017 year to date.

Response:

The bucket truck has been budgeted to be replaced in 2020. The factors that have contributed to this decision are, first, it is a leased vehicle and the lease is a 7 year lease. Second, there is an option to buy the truck at the end of the lease, however there have been issues with the truck since day one. Currently the plan is to replace the truck in 2020, however this will be re-evaluated in 2019 based on the truck’s forecasted maintenance costs. A factor that contributes to the cost for maintenance is that the closest service centre for the truck is 5 hours away. Therefore, in order to have something repaired we have to pay for the mechanic to travel to Sioux Lookout, or send the truck to Winnipeg, leaving us without a truck in case of emergencies. This risk is offset somewhat since we can use our line truck as a bucket truck if needed.

A detailed breakdown of costs from 2015 to 2017 is below:







\*The last amount is estimated, the truck had to be sent to Winnipeg this week for repairs and we have not been invoiced for it yet, however the estimate is based on a quote for the work requested.

1. For each major asset category explain whether a run-to-fail strategy is used. Where run-to-fail is not used, explain how capital spending is prioritized (based on testing or age information only).

Response:

|  |  |
| --- | --- |
| **Asset Category** |   |
| Poles & Wires | Based on age, testing and condition, Refurbishment rarely considered |
| Line Transformers | Run to fail |
| Meters | Run to fail |
| General Plant | Age and condition, refurbishment considered |

Prioritization will depend on safety concerns, impact of failure to customers and of course cost.

Load Forecast (Exhibit 3)

1. Potential to run a regression for each rate class (instead of entire utility). Does this result in a material change to the load forecast?

Response:

In the 2013 cost of service application a separate regression analysis for each rate class was conducted. However, based on the statistical results of the rate class specific regression analysis, SLHI concluded using the equation resulting from the individual rate class regression analysis would not provide a prediction formula that was as good as the prediction equation from the power purchased method. There were no significant changes in the rate class load characteristic supporting the 2018 load forecast that would change this conclusion. As a result, SLHI did not conduct a rate class specific regression analysis in this application.

1. Historical CDM savings – how are these savings factored into the load forecast? If they are not, rationale is necessary.

Response:

The regression analysis that supports the load forecast is based on using actual monthly purchased data from January 2007. The actual purchased data reflects the historical impact of the CDM savings. Since the actual purchased data is used to determine the prediction formula for the load forecast the historical CDM savings have been factored into the load forecast.

1. Mill customer – confirmation that there is no expectation that load from mill will come online during forecast period. Also, potential method to capture variance if load from mill does come online during the forecast period.

Response:

I can confirm that there is no expectation that the load from the mill will come online during the forecast period. If they did, it would be possible to track the additional revenue in a variance account to be dealt with in a later application if directed to do so.

OM&A (Exhibit 4)

1. Tree trimming – how was the test year budget derived?

Response:

Tree trimming is budgeted year by year mainly on historical average cost. It generally does not fluctuate significantly unless there are unplanned external factors that would necessitate increased spending.

1. U/G cable maintenance – is all of the proposed OM&A spending for testing?

Response:

Yes all of the proposed OM&A spending for u/g cable is for cable testing.

1. Monthly billing system charges – explain increase between test year and 2013.

Response:

Please see the attached letter from Thunder Bay Hydro explaining the increase.

1. Bank and merchant fees – explain increase between test year and 2013 and advise whether there has been an attempt to renegotiate these fees.

Response:

Our debit machine supplier added additional service charges in 2016 for System maintenance fees which average over $1,000 per month extra for expenses related to debit and credit card transactions by $13,000 in 2016. There has not been an attempt to renegotiate these fees as of yet, but is planned to be looked into in the next two to three months.

1. Explain what is included in the “other administration and general” cost category and explain the variance between the test year budget and 2013.

Response:



The variance between the test year and 2013 actuals of $35,576 is mainly due to increases in Admin/Management salaries of $21,619 and the inclusion of employee future benefits expense after the transition to IFRS.

1. Advise in which cost category OEB cost assessments are included.

Response:

The OEB Cost Assessments are included in the Regulatory costs, Account 5655.

1. Explain what the $40k in ongoing costs for “operating expenses associated with resources allocated to regulatory matters” is related to. Also, provide the historical year spending on the activities that are included in this cost category.

Response:

SLHI has estimated that it will cost at least $40,000 in consulting fees in order to meet regulatory policy direction. The small number of employees as SLHI means that most often than not, outside help is needed in order to prepare information or implement new policies related to regulatory direction since we lack the expertise.

For example, SLHI does not have internal resources able to respond to the new Cyber Security framework, therefore a third party will be hired initially to aid in the implementation, and then a firm to monitor our IT environment for threats etc. SLHI expects this will be an ongoing expense once implemented.



1. Provide rationale supporting the continued application of useful lives for OH conductors and C&P transformers that are outside the Kinectrics’ minimums.

Response:

The rationale supporting the continued application of useful lives for OH Conductors outside the Kinectrics’ minimums is that if SLH revised the useful lives of this asset category, the change in depreciation will be immaterial. A rough calculation determining what the impact would be is around $3,000 deduction in depreciation for the OH Conductor.

For the C&P transformers, SLH does not break out the costs associated with CTs, PTs and commercial meters and meter bases. These are pooled together in account 1820. SLHI also feels that the change would not produce a material result to justify revising the useful lives of this asset category.

Cost of Capital (Exhibit 5)

1. Provide information on attempts to renegotiate interest rate or find alternative lender for the 2018 bucket truck loan.

Response:

I am currently negotiating the interest rate for the truck. So do not have any additional information at this time.

Cost Allocation (Exhibit 7)

1. Adjust GS < 50 kW rate class R/C ratio to stop at unity.

Response:

The GS < 50 kw rate class is adjusted to stop at 100%. I have updated the Revenue Requirement Workform to reflect this. The impact has been a slight increase to the Residential Class from the current application going from a $5.76 distribution rate increase to $5.97. The bill impact model has been revised to reflect this.

1. Advise whether the proposed change to the cost allocation for the street lighting class can be phased in over 3 years (with associated reductions in years 1 and 2 apportioned to the residential and GS < 50 kW rate classes).

Response:

I did discuss this option with the street lighting customer, and they are not willing to have it phased in over three years. Having said that, the rate impact to the Residential rate class is well below the 10% that triggers a need for mitigation. The impact to customers of no phase in vs a three year phase in, is an increase of $1.11 or .8% on their total bill

Rate Design (Exhibit 8)

1. Explain whether the load forecast can be used to inform expected low voltage volumes (or explanation as to why use of historical average is more appropriate).

Response:

SLH feels that the historical average is representative of the future as it expects the low voltage volumes to remain steady over the forecast period.

1. Provide further rationale supporting the proposal to increase the GS < 50 kW rate class fixed charge above the ceiling from the cost allocation model. Otherwise, consider following the OEB’s general policy and setting the fixed charge for GS < 50 kW rate class no higher than the ceiling (and revise the application to reflect this change – including the bill impacts).

Response:

SLH has revised the GS < 50 fixed rate charge to $46.00 which is the ceiling. The bill impacts have been updated to reflect this.

Therefore I have submitted a bill impact model to illustrate the impacts for the change made to bring the GS < 50 rate class to parity, and the fixed charge to the ceiling of $46. This is labeled as the “No transition” bill impact model.

The second impact model is to illustrate the impact in the first year if we were to transition the street lighting rate class over a three year period, but also includes the changes made to the GS < 50 kW as stated above.

Below is a table illustrating the original application and the two scenarios above:

