# Board Staff Supplemental Interrogatories

Hydro One Remote Communities Inc.
EB-2012-0137
May 6, 2013

A – Staff – 36s

## Extending Service to Grid-connected Communities

References:

- Exhibit I / 2 / 2
- Exhibit A / 3 / 1 / p. 1
- EB-2004-0545, response to Staff interrogatory 4 (i), included as Attachment A to these interrogatories

In Exhibit I / 1 / 2, Remotes provided a single line diagram for the connection to the Provincial grid of both Cat Lake First Nation and Pikangikum First Nation. In regard to demarcation points on the diagram, and in particular to estimating the electrical losses on the connection to Cat Lake, Remotes indicated that:

- a computerized power flow simulation has been conducted for Cat Lake, the electrical losses from metering point to the community are estimated to be 2.46% at its peak loading conditions;
- facilities currently owned by Community of Cat Lake are shown marked on the drawing as part of the response to part a) of this interrogatory. Hydro One subsidiaries will take over these assets. Remotes expects to own the 75km of distribution line. However the final demarcation point has not been determined;
- Hydro One Networks - Transmission will continue to own the 115 kV line E1C from which the 18 kilometer line tap to Cat Lake substation is supplied.

The fourth reference is a response to an interrogatory, dated March 22, 2005, in EB-2004-0545. This proceeding was a joint application for Leave to Construct by De Beers Canada Inc, Five Nations Energy Inc, and Hydro One Networks Inc. The results of peak losses of approximately 450 km of 115 kV line supplying the De Beers mine range between 6.8 MW and 7.82 MW in serving a 20 MW load, in other words 25% or more.

Board staff notes that losses on a 25 kV line is typically expected to be more than 16 times the losses on a 115 kV line, for the same amount of power transferred and for the same line length. Prorating these results to the connection to Cat Lake, assuming 1/6 of the line length (75 km) at 25 kV, the line losses would be in the range between 15% and 25 %.

Questions / Requests:

a) In regard to the computerized power flow simulation for Cat Lake resulting in an estimate of 2.46% at its peaking loading condition, please provide the following:
    i. Size of the conductors used;
    ii. The peak loading assumed for Cat Lake;
    iii. The length of the 25 KV line assumed in the simulation; and
    iv. Additional assumptions that were assumed that lead to the reported results of 2.46 % losses for Cat Lake.
b) With regard to Cat Lake, if the assumption of the length of the 25 kV line was less than 75 km as shown in the map, please repeat the calculation assuming that 75 km to be incorporated in the loss evaluation.
c) Please comment on the calculation that line losses would be in the range between 15% and 25%.

A – Staff – 37s

References:

- Exhibit I / 2 / 2
- Exhibit A / 3 / 1 / p. 1
- Exhibit G1 / 1 / 2 / p. 4

In Exhibit I / 1 / 2, Remotes provided a single line diagram for the connection to the Provincial grid of both Cat Lake First Nation and Pikangikum First Nation. In regard to demarcation points on the diagram, and in particular to estimating the electrical losses on the connection to Pikangikum, Remotes indicated that:

- Remotes is unable to estimate the electrical losses for Pikangikum as no computerized model is readily available to conduct the simulation;
- The Hydro One facilities currently owned by the Community of Pikangikum are also shown on the drawing. The community is currently supplied by local Diesel Generation. Future ownership plans are that Hydro One Remotes will take over the community distribution system and the new supply feeder;
- A loss factor of 1.5% has been used in this application, reflecting the close proximity of generation to load in remote communities.

Questions / Requests:

a) Please provide an estimate of the losses for Pikangikum using the computerized power flow simulation listing all assumptions including:

i. Size of the conductors;
ii. The peak loading for Pikangikum;
iii. The length of the 25 KV (from the Metering Point to the Community); and
iv. Any additional assumptions relevant to the evaluation.

b) Who will construct, pay for and own the new 100 Km 44 kV line between Red Lake TS and Pikangikum DS (is it Hydro One Networks Inc. – Distribution ("HONI-Distributuion")?
c) If the response to e) indicates that HONI-Distributuion will be the owner of the noted 44 kV line, would Remotes be paying he LV Service Rates for the power delivery to Pikangikum in addition to the Retail Transmission Rates?

A – Staff – 38s

Reference:

- Exhibit I / 1 / 6 (f)

Please provide the information, or a summary if too voluminous, that Remotes has provided to the OPA, AANDC and First Nations "to assist in the development of a business case for transmission to the north"

A – Staff – 39s

**Pensions and OPEB**

References:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)
- Exhibit A-11-1, Attachment 3 (2011 Financial Statement)

On April 24, 2013, Remotes submitted its US GAAP December 31, 2012 audited financial statements at Exhibit I-1-4 Attachment 3. Remotes has recorded a $3,144,000 regulatory asset as at December 31, 2012 for "Post-retirement and post-employment benefits." (p. 18) Note 2 of the same reference includes the following explanation regarding the regulatory asset for "Post-retirement and post-employment benefits" at p. 13 (p. 81 of 565):

> "The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on

annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for postretirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI [“Other Comprehensive Income”]. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.”

Board staff notes that neither a regulatory asset nor a regulatory liability was recorded in the December 31, 2011 CGAAP audited financial statements for “Post-retirement and post-employment benefits”.

Questions / Requests:

a) Please explain in more detail the section of Note 2 of the audited financial statements referenced above regarding the $3,144,000 regulatory asset for “Post-retirement and post-employment benefits.” Please explain why this balance was recorded in the 2012 US GAAP audited financial statements and not the 2011 CGAAP audited financial statements.
b) Please explain how and when Remotes is proposing to recover the $3,144,000 regulatory asset for “Post-retirement and post-employment benefits” in rates.
c) Please explain why this balance should not instead by charged to the shareholder in the company’s accumulated other comprehensive income. As noted above, Remotes has recorded a regulatory asset for “Post-retirement and post-employment benefits” or “OPEB” in its financial statements. However, Remotes has not received a rate order by the Board to report such an asset. ASC 980-715-25-5 requires an order by the regulator.
    i. Why did Remotes not apply for such an order from the Board?
    ii. Does Remotes plan to apply for such an order from the Board?
    iii. Please clarify if this OPEB regulatory asset was $1,528,000 as at January 1, 2011, as noted in Note 18 (page 29) to the December 31, 2012 audited financial statements. If this was not the number, please provide the correct number.

A – Staff – 40s

Reference:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

How has Remotes recovered the following in past rates, and how does Remotes propose to recover these items in future rates:

a) Transitional asset/obligation generated on transition to CICA HB Section 3461. Please disclose initial amount and date and unamortized amount to date.
b) Transitional asset/obligation generated on transition to US GAAP. Please disclose initial amount and date and unamortized amount to date. Please confirm that these amounts were $1.528 million regulatory asset for OPEB as at January 1, 2011 under USGAAP.
c) Recognizing unamortized actuarial gains and losses and past service costs on the balance sheet under US GAAP

A – Staff – 41s

Reference:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

USGAAP does not recognize transitional assets/obligations generated from the transition to CICA HB Section 3461.

How did Remotes treat the unamortized amount on the transition to USGAAP?
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A – Staff – 42s

References:

- Exhibit I / 1 / 4(b)
- Board Staff IR #5

In the response to Board Staff IR#4(b), Remotes stated that it is proposing to recover its pension costs on a defined benefit cash basis, as follows:

> "Remotes recovers its pension costs in rates using the defined benefit cash basis, consistent with other Hydro One subsidiaries including Networks."

However, as noted in the preamble to Staff IR#4, the Remotes 2011 and 2012 audited financial statements articulates that Remotes records pension costs in its books on a defined contribution basis.

<u>Questions / Requests:</u>

a) Please provide reasons as to why the Board should approve recovery of Remotes pension costs on a different basis than that recorded in the audited financial statements (i.e. recover in rates on a defined benefit cash basis and record in books on a defined contribution basis).

b) Please explain why Remotes is applying for pension costs on a different basis (defined benefit cash basis) than that recorded in its audited financial statements. What are the external auditor's views on this fact?
c) Please provide an estimate of what Remotes 2013 pension cost would be using the defined contribution basis, including an explanation of the assumptions used in the calculations.
d) In the response to Board Staff IR#5, Remotes stated that actual 2009, 2010, 2011, and 2012 audited pension costs have been "sourced from financial system."
    i. Please describe how these costs were "sourced from financial system" and the basis of the sourcing.
    ii. Please explain why Remotes was able to source these amounts from the financial system, but these amounts were not included in the audited financial statements.
    iii. What are the external auditor's views on Remotes being able to source the pension costs from its system on a defined benefit cash basis, but recording the pension costs in its audited financial statements on a defined contribution basis?

A – Staff -- 43s

References:

- Exhibit I-1-4, Attachment 1 (Pension Plan Actuarial Evaluation)
- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

As per Note 2 (page 13) of the December 31, 2012 audited financial statements, the Hydro One Inc. ("Hydro One") contributory defined benefit pension plan covers all regular employees of Hydro One and its subsidiaries, including Remotes and excluding Hydro One Brampton Inc.

Remotes provided the Hydro One Pension Plan "Report on the Actuarial Valuation for Funding Purposes as at December 31, 2011" as Attachment 1 to its response to Board Staff interrogatory #4.

Remotes stated that there is a later funding valuation available in the response to Board Staff interrogatory #4, with an effective date of December 31, 2012.

Questions / Requests:

a) Please confirm that the December 31, 2011 Hydro One valuation was prepared on the defined benefit cash basis.
b) Please provide the latest Hydro One valuation with an effective date of at December 31, 2012.
c) Has Mercer or another actuary ever prepared an Actuarial Valuation for Hydro One based on the accrual basis of accounting for pension expense? If so, please provide the latest valuation.

A – Staff -- 44s

Reference:

- Exhibit I-1-5

In the response to Board Staff interrogatory #5, Remotes provided unaudited numbers for the 2012 pension and OPEB costs  The response included an explanation for the increase in pension and OPEB costs from 2009 through 2012, but no explanation from 2012 to 2013.

a) Please update the 2012 pension and OPEB costs in the table provided in the response to Board Staff interrogatory #5 with the audited numbers.  Please update 2013 pension and OPEB costs in the table and any other appropriate evidence, if applicable.
b) Please provide an explanation for the increase or decrease in pension and OPEB costs from 2012 to 2013.

A – Staff -- 45s

**Cost of Remediation of Contaminated Land**

References:

- Exhibit C1-4-1
- Exhibit I-1-4, Attachment 3
- Exhibit I-1-29

In the response to Board staff interrogatory #29, Remotes stated that its environmental expense for 2012 and 2013 is expected to be $2,515,000 and $2,713,000 respectively, and provided the following table.

**Remotes LAR Amortization Expense**

**$ Thousand**

| **Actual** | | | | **Plan** | | | | |
|---|---|---|---|---|---|---|---|---|
| **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
| 983 | 1,268 | 1,017 | 2,515 | 2,713 | 1,487 | 1,589 | 1,134 | 1,284 |

In the December 31, 2012 audited financial statements, Exhibit I-1-4, Attachment 3, submitted April 24, 2013, (note 13 on p. 23, p. 91 of 565) Remotes disclosed the following information:

> "As a result of its annual review of the environmental liabilities, the Company recorded a revaluation adjustment to reduce the LAR environmental liability by $583 thousand"

In the same note, Remotes updated its estimated future environmental expenditures as follows:

- 2013 - $1,823 thousand;
- 2014 - $2,783 thousand;
- 2015 - $1,457 thousand;
- 2016 - $980 thousand;
- 2017 - $1,104 thousand.

Board staff notes that the average of these five amounts is $1,630 thousand.

<u>Questions / Requests:</u>

a) Please provide an updated version of the table titled "Remotes LAR Amortization Expense".
b) Please describe the circumstances, assumptions and calculations used to arrive at the revaluation adjustment representing a $583,000 reduction in the environmental liability as at December 31, 2012.
c) Please comment on whether the amount of $1,630,000 would be a more suitable amount of Amortization Expense to include in Table 2 of Exhibit C1-4-1, p. 3, and in Remotes' revenue requirement. If so, please update the applicable evidence.

A – Staff – 46s

References:

- Exhibit A-8-1
- Exhibit I-4-12, parts a and c
- Exhibit I-1-18, part c
- RP-1998-0001, Appendix D to Rate Order,(OHSC Distribution), pp. 55-57

In its response to NAN interrogatory #12 concerning the cost of remediating contaminated land, in particular the site of a fuel tank at Attawapiskat, Remotes has cited the OEB's decision RP-1998-0001. Board staff notes that the decision on Distribution rates mentions 21 communities (at p. 56), and approved amounts for remediation in 1999 and 2000. From this information, it appears that the decision on OHSC rates in 1999 is not pertinent to remediation in Attawapiskat, Cat Lake, and Pikangikum.

<u>Questions / Requests:</u>

a) Please confirm that the 21 communities alluded to in the RP-1998-0001 proceeding are the same ones as are listed in the current application at Exhibit A-8-1, p. 1, Alternatively please provide a reference in the record of RP-1998-0001 to support a contention that the OEB approved remediation in some or all of these locations.
b) If RP-1998-0001 is not a suitable reference for the cost of remediation outside of the 21 communities served by Remotes, please provide an alternative reference(s) to regulations or OEB decisions which support Remotes' assumption of remediation costs in such locations.
c) Are there any other environmental liabilities from the legacy Ontario Hydro that have been assumed by Remotes in areas that Remotes does not currently service?
d) What are the criteria for Remotes recording some environmental liabilities and not others (both constructive and legal obligations)?

C – Staff -- 47s

References:

- EB-2008-0232, Exhibit C1-2-2, Appendix A
- Exhibit C1-4-1
- Exhibit I-1-4, Attachment 3
- Exhibit I-1-18, part c

In its response to Board staff interrogatory # 18 c, (pp. 311-312 of 565), Remotes has included an agreement for decommissioning and soil remediation in Attawapiskat, which was generated in 2007 and now includes an update of Remotes' cost at $664,765. This cost is larger than the amount that was included in Remotes' previous cost-of-service rate application EB-2008-0232, which was $150,000. It is also larger than the cost included in this application, which was $350,000. (Exh C1-4-1 p. 4)

Questions / Requests:

a) Please explain why the cost of this project has increased to such an extent.
b) Does the amount of the Environmental Liabilities in Remotes' 2012 audited Financial Statement at Exhibit I-1-4c, note 13 (p. 91 of 565) reflect the largest of the three amounts, or a lower remediation cost forecast such of one of the other amounts cited in the preamble?

C – Staff -- 48s

References:

- Exhibit I / 1 / 9
- Attachment 4 – 2E Project Table (filed October 31, 2012)

Remotes has explained that federal funding was received for the staff house in Marten Falls. According to the project tables provided in Attachment 4, other staff houses have been built or renovated at considerable cost including four staff houses at more than $400k each (Kingfisher, Sandy Lake, Fort Severn, Webeque)

What criteria are used to determine which staff houses are funded similar to Marten Falls, which are funded by Remotes alone, and which if any are funded by some other cost-sharing formula?

F – Staff -- 49s

References:

- Exhibit I-1-4, Attachment 3
- Exhibit F1-1-1, Appendix D

In its pre-filed evidence submitted in September 2012, Exhibit F1-1-1 Appendix D, Remotes forecasted a debit balance of $747,000 in the RRRP variance account as at December 31, 2012.

On April 24, 2013, Remotes submitted its US GAAP December 31, 2012 audited financial statements at Exhibit I-1-4 Attachment 3. The audited balance of the RRRP variance account as at December 31, 2012 is now available, per Note 9 of the audited financial statements in Exhibit I-1-4, Attachment 3, p. 18 (p. 86 of 565). Board staff notes that the audited balance in the Regulatory Asset account is a debit balance of $787,000 as at December 31, 2012.

<u>Questions / Requests:</u>

a) Please confirm that the December 31, 2012 actual audited balance of the RRRP variance account is a debit balance of $787,000.
b) Please update the evidence in Exhibit F and any other appropriate evidence leading to this revised balance.
c) Please describe the reason for any substantial revisions in the line items in Exhibit F.

Attachment A – excerpt from EB-2004-0545 re loss calculation

Attachment B – excerpt from Decision RP-1999-0001 re land remediation

Response to Board staff interrogatory 4, Question (i), dated March 22, 2005 in regard to a joint application for Leave to Construct by De Beers Canada Inc., Five Nations Energy Inc., and Hydro One Networks Inc. (Board File No. EB-2004-0545)

4. ***Note: This IRR requires response from both Hydro One and FNEI, or alternatively, if feasible a single response covering the two transmitters.***

Ref. (a) Exh. B / Tab 3 / Sch. 3 / Addendum / p. 3
Ref. (b) Exh. A/ Tab 3/ Sch. 1/ from p. 6 (line 17) to p.7 (line 7)
Ref. (c) Exh. B/ Tab 5/ Sch. 1

**Preamble:**

(1) In Ref. (a), which is part of the IESO's "Preliminary Assessment Report: Addendum"., it is indicated that with a new 230 kV line (operating at 115 kV) from Otter Rapids GS to Moosonee DS and a new 115 kV line from Moosonee DS to Fort Albany, the total losses would be 10.8 MW. This assumes a maximum load of 27 MW at the Victor Mine.

(2) It is also stated in Ref. (a) that "if the new line were to be extended an additional 11km from Fort Albany S/S to Kashechewan S/S, the 10.8 MW losses would be further reduced."

**Questions/Requests:**

(i) Please provide an estimate of the power losses for the current proposal which includes:
- a 180 km,115 kV line from Abitibi Canyon Junction and Moosonee SS
- a 170 km, 115 kV line from Moosonee SS to Kashechewan SS (Note that this includes the 11 km section Fort Albany SS and Kashechewan SS.)
- a 100 km, 115 kV line from Attawapiskat TS to the Victor Mine
- a maximum load of 20 MW at the proposed Victor Mine

**<u>Answer (i) and (iv)</u>**

| | **Reference Plan** | **Smaller conductor in FNEI system** | **Smaller conductor in FNEI & Hydro One systems** |
|---|---|---|---|
| Otter Rapids to Moosonee SS | 795 kcmil | 795 kcmil | 477 kcmil |
| Moosonee SS to Kashechewan SS | 795 kcmil | 477 kcmil | 477 kcmil |
| Attawapiskat to Victor Mine | 477 kcmil | 477 kcmil | 477 kcmil |
| **Line Section** | **Peak losses (MW)** | **Peak losses (MW)** | **Peak losses (MW)** |
| Pinard x Otter Rapids | 1.09 | 1.1 | 1.13 |
| Otter Rapids x Moosonee | '2.55 | 2.59 | 3.16 |
| Moosonee x Kashechewan | 1.24 | 1.52 | 1.56 |
| Kashechewan x Attawapiskat | 1.52 | 1.54 | 1.57 |
| Attawapiskat x Victor Mine | 0.4 | 0.4 | 0.4 |
| **Total** | **6.80** | **7.15** | **7.82** |

This table shows the peak losses with the forecasted load for the year 2020.

(ii) Please confirm whether or not power losses were included in the economic evaluation assessments of the alternatives considered [see Ref. (b) and Ref. (c)].

Attachment B

Board Staff Supplemental Interrogatory 46s

Excerpt: pp. 53-57

Appendix "D" to Rate Order
RP-1998-0001 Distribution
March 15, 1999

Paul B. Pudge

Paul B. Pudge
Board Secretary

## 4. ADDITIONAL OHSC OPERATIONS

This chapter addresses regulatory issues pertaining to business activities that OHSC proposed to operate either as a separate line of business, as in the case of Remote Community Operations, or as a separate affiliated company, as in the case of Retail Monopoly Supply.

### REMOTE COMMUNITIES

In addition to its traditional distribution system, OHSC owns and operates generation and distribution systems in 21 remote (off-grid) communities serving approximately 3,700 customers across northern Ontario.

Historically, remote communities' customers received two basic forms of subsidy. First, in many instances the Federal and Provincial governments funded the original cost of installation as well as the incremental capital cost associated with expansion. Second, the high cost of generation and distribution of electricity for remote communities was included in the generation and distribution for the entire system. A number of remote community customers pay only the system wide rural rate price for electricity, versus the much higher local actual cost, creating a subsidy from other system customers.

Under the proposed reorganization, the management and operations associated with these remote communities will be a separate line of business with a separate revenue requirement. OHSC requested approval of existing rates for remote communities and identification of the remote community assistance/compensation required.

The Act requires the Board, in approving rates for a distributor who provides electricity to remote community customers, to provide rate protection in accordance with government regulations. OHSC assumed that the regulation would provide for rate protection consistent with current rates. The distributor is entitled to be compensated for the lost revenue associated with the rate protection approved by the Board.

The following table summarizes OHSC's proposed Remote Community revenue requirement.

Proposed Revenue Requirement ($Millions)

| Item | 1998 | 1999 | 2000 |
|---|---|---|---|
| Fuel | N/A | 8.3 | 8.6 |
| OM&A | | | |
| Distribution | 1.3 | 2.6 | 2.7 |
| Generation | 6.5 | 5.5 | 5.3 |
| Environmental | 2.0 | 7.5 | 7.0 |
| Total OM&A | 9.8 | 15.6 | 15.0 |
| Depreciation | N/A | 2.4 | 4.5 |
| Interest Expense | N/A | 2.2 | 2.3 |
| OHSC Overheads | N/A | 0.9 | 0.9 |
| Total Revenue Requirement | N/A | 29.4 | 31.3 |

Because remote communities receive a subsidy, according to OHSC it does not make sense that they should earn a return on equity because the return on equity would also have to be subsidized. In order to prevent such an increase in the total subsidy for remote communities the proposed capital structure is 100% debt.

The current "standard rate" and "standard A rates" were forecast to produce $12.8 million in revenue for 1999 and $12.6 million in 2000. Based on the current rate structure and the revenue requirement requested by OHSC, the amount of lost revenue for which compensation will be required would be $16.6 million for 1999 and $18.7 million in 2000 respectively.

OHSC proposed to increase its staff level by 7 employees to 35 full time staff, a 25% increase. OHSC did not provide any information reconciling staff levels to operational programs. OHSC explained that staffing on a customers-per-employee basis is higher for remote communities since: (1) staff deal with both generation and distribution creating greater staffing level requirements; and (2) remote communities are not located in the same vicinity, requiring additional utility staffing in each community. Offsetting this are contracts with local people "who will take care of some of the activities, but not all of them".

As outlined below, OHSC's proposed to increase environmental expenditures for remote communities by $5.5 million from $2.0 million in 1998 to $7.5 million in 1999 (and $7.0 million in 2000) as they are undertaking a significant land remediation program.

Details of 1999 Environmental Cost Increase

| | |
|---|---|
| Completing Phase 2 site assessments | $1.0 M |
| Establishing an Environmental Management System | 0.5 |
| Site remediation at 3 sites | 1.5 |
| Property boundaries definition | 1.0 |
| Compliance with new Fuel Oil Regulations | 1.5 |
| **TOTAL** | **$5.5 M** |

**Board Findings**

The Board accepts OHSC's proposal regarding the maintenance of current rate levels for Remote Communities, and accepts the proposed revenue of $12.8 million in 1999 and $12.6 million in 2000 for the purposes of determining the compensation requirement of Remote Communities. The Board is mindful in its review of the revenue requirement for Remote Communities that, while the source of remote community assistance/compensation is not yet determined, a significant portion of the revenue shortfall will likely be derived from sources other than OHSC's customers. Ultimately, freezing rates means increases in program cost will be directly reflected in both the revenue requirement and the compensation required. Since much of the cost increases will be borne by others (many of whom may be competitors of OHSC's distribution business), the analysis and justification requirements will be particularly stringent.

The Board accepts OHSC's proposed capital programs for Remote Communities. However, in concert with the Board's findings on Working Capital elsewhere in this Decision, the Board will adjust the amounts correspondingly for the calculation of revenue requirements to exclude OPEB and Deferred Pension working capital provisions. The Board has determined that the impact of this adjustment is to reduce interest expense (and consequently revenue requirement) by $0.3 million in 1999 and 2000 respectively.

The Board is unconvinced by the evidence presented that seven additional employees as proposed by OHSC are required. OHSC states that its Remote Communities business strategy involves automation of key operating functions including meter reading, and development of First Nations contract agents to allow more local involvement (16 of 21 communities operate under First Nations service agreement contracts). The Board is of the view that these initiatives should reduce, not increase, staff requirements. In this regard these Remote Communities have operated separately with fewer employees than requested in the application. Therefore, for the purpose of establishing the Remote Community revenue requirement, the Board has not included OHSC's proposed staff increase. Accordingly, the Board has reduced revenue requirement by $700,000 per year, reflecting its computation that the fully burdened cost of an average OHSC employee is approximately $100,000 per year.

With respect to the significant increases requested for environmental expenditures, the Board understands the need to address these issues, but also recognizes that many programs are being established to address long standing problems. The Board observes that there was considerable imprecision expressed regarding the details of the programs presented. In particular, the Board is concerned with the environmental program relating to boundary definition expenditures. OHSC explained that they have to identify what the original boundaries were for contaminated sites, who has been using that land recently, and, depending on contamination levels, OHSC may install fencing to prevent certain activities. For cost allowance purposes, the Board has assumed that OHSC will focus this program on sites adjacent to potentially contaminating activities based on OHSC's extensive experience in these sites. The Board therefore will allow an expenditure level of $6.5 million for 1999 and year 2000 respectively environmental activities, reflecting the concern on the cost imprecision in general, and the activity level and cost justification for the boundaries program in particular.

As a result of the above adjustments of $2.0 million in 1999 and $1.5 million in 2000, the Board approves a revenue requirement of $27.4 million for 1999 and $29.8 million for 2000 as summarized below. The resulting compensation requirement, based on revenues of $12.8 million and $12.6 million in 1999 and 2000 respectively, is $14.6 million in 1999 and $17.2 million in 2000.

Board-Approved Revenue Requirement ($Millions)

| Item | 1999 | 2000 |
|---|---|---|
| Fuel | 8.3 | 8.6 |
| OM&A | | |
| Distribution | 2.6 | 2.7 |
| Generation | 5.5 | 5.3 |
| | | |
| Environmental | 6.5 | 6.5 |
| Staffing Adjustment | (0.7) | (0.7) |
| Total OM&A | 13.9 | 13.8 |
| Depreciation | 2.4 | 4.5 |
| Interest Expense | 1.9 | 2.0 |
| OHSC Overheads | 0.9 | 0.9 |
| Total Revenue Requirement | 27.4 | 29.8 |

RETAIL MONOPOLY SUPPLY

OHSC plans to conduct the Retail Monopoly Supply function in a separate affiliated company. OHSC believed this arrangement to be consistent with Section 50 of the Electricity Act which would prohibit OHSC's transmission or distribution subsidiaries from