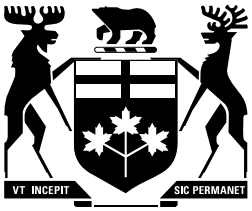

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2009 ELECTRICITY DISTRIBUTION RATES

LAKELAND POWER DISTRIBUTION LTD. (“Lakeland”)

EB-2008-0234

February 20, 2009

Introduction

Lakeland Power Distribution Ltd. is owned by Lakeland Holding Ltd. which is jointly owned by the Municipalities of Bracebridge, Huntsville, Burk's Falls, Magnetawan and Sundridge. Lakeland serves approximately 7,500 Residential customers, 1,500 smaller General Service customers and 96 larger General Service customers (in the above named municipalities). Lakeland filed its 2009 rebasing Application on September 15, 2008. The Application was based on a future test year cost of service methodology.

On December 19, 2008, Lakeland filed with the Ontario Energy Board (the "Board") its responses to the written interrogatories ("IRs") from Board staff and other parties. On January 29, 2009, Lakeland filed with the Board its responses to the second round of written interrogatories.

In Procedural Order No. 2, the Board determined that this application would proceed by way of a written hearing process, and in Procedural Order No. 4 sought submissions from the Board staff and parties to this proceeding.

The following issues are addressed in these submissions:

- Load Forecasting – Methodology, Model, Results and Analysis
- Rate Base and Capital Expenditures
- Cost of Capital and Capital Structure
- Operating, Maintenance & Administrative Expenses
- Payments in Lieu of Taxes: Calculation of PILS
- Cost Allocation
- Rate Design (Monthly Fixed Charges, Unmetered Scattered Load, Low Voltage rates, Retail Transmission Service Rates
- Loss Factors
- Deferral and Variance Accounts

These submissions reflect observations and concerns which arise from Board staff's review of the pre-filed evidence and interrogatory responses ("IRs") made by Lakeland, and are intended to assist the Board in evaluating Lakeland's application and in setting just and reasonable rates.

Load and Revenue Forecast

Background

Lakeland discussed the development of its customer count forecast and load forecast in Exhibit 3 of its September 15, 2008 filing. It determined the 2008 Bridge Year and 2009 Test Year customer count by class using historical data. It also determined the kWh forecast – and the kW forecast for appropriate classes – by customer class and presented variance analyses in support of the forecasts.

The Applicant provided additional information in response to two rounds of Board staff, VECC and Energy Probe forecasting interrogatories and one round of SEC forecasting interrogatories. On December 18, 2009, in response to the initial round of interrogatories the Applicant filed a revised section of its Exhibit 3 that provided additional clarity while leaving the initially-filed forecast largely intact.

Discussion and Submission

Methodology and Model

The forecast for the number of customers by rate class was determined using time-series analyses. The weather-normalized load forecast was developed in a three-step process. First, a total system weather-normalized *purchased* energy forecast was developed based on a multifactor regression model that incorporated historical load, weather, economic data, number of customers and calendar factors. Second, the weather-normalized purchased energy forecast was adjusted by a historical loss factor to produce a weather-normalized *billed* energy forecast. Finally, the forecast of *billed energy by rate class* was developed based on a forecast of customer numbers and their historical usage patterns. For the rate classes with weather-sensitive load, their forecast billed energy was adjusted to ensure that the total of the billed energy forecast by rate class was equivalent to the previously-obtained total weather-normalized billed energy. For those rate classes that use kW for the distribution volumetric billing determinant, the kWh forecast was modified by applying a conversion factor to the class energy forecast based on the historical relationship between kW and kWh. Board staff regards this methodology and model as a sound weather-normalized load forecasting methodology.

Results

The customer count historical growth was 0.8% per annum which is the same value as the forecast. The 2009 forecasted customer count is 9,303. The kWh historical growth

was 1.4% per annum whereas the forecast load shows a negative 0.3% per annum growth. The 2009 forecast load is 225.9 GWh.

Analysis

Prior to the interrogatory process, Board staff noted various minor errors/ambiguities. Further issues subsequently arose and are discussed below.

In reply to Board staff IR #25, the Applicant stated that it had discovered that it had used the incorrect loss factor in converting from wholesale load to billed load. While this error had the effect of increasing the forecast by some 3%, nevertheless, as a mitigation strategy it proposed maintaining its filed load forecast. The Applicant reiterated its intended mitigation strategy in reply to VECC supplemental IRs #5 and #8.

In its reply to Board staff IR #23, the Applicant confirmed that the anticipated effects of its CDM program had not been reflected in the forecast. Board staff notes that this omission has the effect of increasing the load forecast by 1% or 2%. (This is in addition to the loss factor related 3% noted above.)

In response to Board staff IR #24 which sought to understand why an apparently out-of-date economic forecast had been used, the Applicant explained that a more up-to-date forecast had not been used since the Ontario Real GDP variable was not a significant contributor to the regression formula. Board staff notes that this appears to be contradicted by the statement in Exhibit 3, Tab 2, Schedule 2, page 1: “The multifactor regression model has determined [the] primary driver of year-over-year changes in LPDL’s load growth are economic conditions and weather.” However, in response to VECC IR #4 and Board staff supplemental IR #5, the Applicant provided an alternate forecast that counter intuitively indicated the forecast would have been approximately 2% higher if more up-to-date economic data had been used in the development of the forecast.

Board staff notes that evidence has been filed that indicates the forecast customer count is slightly low. Evidence also indicates the forecasted load to be variously low or high depending on the factors being considered. The net effect of the possible forecast variations points to a load forecast that is most likely to be on the high side with consequential lower rates. There is only a small likelihood of the forecast being too low. Given the Applicant’s repeatedly-expressed willingness to tolerate a slightly higher

forecast in support of rate mitigation, Board staff submits that the load forecast as submitted is satisfactory.

Rate Base

Lakeland is requesting approval of $15.5 million for the 2009 rate base. This amount is a 2.1% increase ($315,061) from Lakeland's 2007 actual and a 1.7% increase ($256,285) from 2006 actual[1].

Capital Expenditures

Background

Lakeland has proposed 2009 capital expenditures of $1.7 million. This represents an increase of approximately 73% compared to the 2008 projected level of $974,788 and an increase of approximately 100% over 2007 actual capital expenditures of $844,283.

Discussion and Submission

Table 1 lists the percentage change of the capital expenditures from the 2007 actual to the 2009 Test year.

Table 1

	2007 Actual	2008 Bridge	2009 Test
Capital Expenditures	$844,283	$974,788	$1,685,160
% change from prior year		15%	73%

Lakeland has experienced general growth for the past few years. However, the Applicant has indicated that due to a small number of line staff, they have been unable to address many of the capital projects that are required to keep the distribution system up to date. Lakeland believes that it needs to start reinvesting in the system to improve system reliability, quality of service and to ensure that future capacity requirements are provided for.

One of the largest expenditure items for 2009 is a 10 MVA distribution station ($500,000) to service an expansion customer that requires approximately 5 MVA. The Applicant was asked in Energy Probe IR #12 about other alternatives and the rationale to undertake such a costly option. Lakeland responded that it did consider other options but now that

[1] Response to SEC IR No. 4, Revised table Exhibit 2/Tab1/Schedule 1/p.1

another developer has indicated that it would also locate at the stated site absorbing additional capacity, the justification for selection a higher capacity option is moot. In response to Energy Probe supplementary IR #13, the Applicant noted that the current estimate for the substation is $2.3 million. With a contributed capital of $1.4 million, the new estimate for capital spending on Lakeland's part is $879,000 as compared to the $500,000 in the original application. However, it is not clear whether Lakeland intends to request the additional amount as part of this application.

The other significant 2009 projects include:

- The Liddard Street project related to underground infrastructure that is more than 30 years old. Costs are based on concrete encased duct for 520 meters. ($182,160)
- The Centre Street project that includes replacement of 15 poles and 750 meters of overhead line. ($150,000)
- Installation of 1000 meters of 16kV 3-phase line and 25 poles from Kirk Lane to Taylor Road. This will allow a tie-in between stations and enhance service reliability. ($250,000)
- Replacement of two vehicles ($205,000)

In the first round of interrogatories, Lakeland was asked [Board staff IR #2b] whether any projects would be candidates for deferral, cancellation or partial adjustment given the current economic environment. The Applicant responded emphasizing the need to start reinvesting in their system. Lakeland maintained that the cutting of any capital investment will only result in higher maintenance costs. Lakeland confirmed that it has not been investing at the rate of depreciation. Consequently, the only item that it could defer is the replacement of a pick-up truck costing $45,000.

Lakeland also revised its proposed 2009 capital expenditures to $1.8 million in response to interrogatories. [Energy Probe IR #11] The Applicant indicated that it had deferred a project to 2009. It has also purchased a bucket truck much earlier than expected and moved this amount to 2008 from 2009. Also, due to high maintenance costs, an additional pick up truck was replaced in 2008 and will be taken out of the 2009 budget. A number of smaller software and hardware items are also deferred to 2009.

Board staff invites parties to comment on whether Lakeland's revised capital expenditures for 2009 are appropriate. Board staff also invites Lakeland to clarify whether it will be requesting a revised amount in this application.

Cost of Capital

Background

Lakeland has provided its proposed Cost of Capital in Exhibit 6. The following table summarizes its proposals in this area:

Table 3

Cost of Capital Parameter	Applicant's Proposal
Capital Structure	Requesting Board approval of a capital structure of 56.67% debt and 43.33% equity. This is to comply with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 20, 2006 (the "Board Report").
Short-Term Debt	Requesting a 4% short-term debt component with a rate of 4.47% in accordance with the letter from the Board of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications, consistent with the Board's Report
Long-Term Debt	Proposing a weighted debt cost rate for 2009 of 5.16%
Return on Equity	Proposing a return on equity rate for the 2009 Test year of 8.57% in accordance with the Board's letter of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications consistent with the Board's Report.

Discussion and Submission

Capital Structure

Lakeland states that it has a current (2008) capital structure of 53.33% debt and 46.67% equity and is requesting Board approval of a capital structure of 56.67% debt and 43.33% equity. Lakeland is requesting this change primarily to comply with the Board Report which requires all licensed Ontario electricity distributors to move toward a 60% debt and 40% equity ratio.

Board staff notes that Lakeland's proposal appears to be consistent with the Board Report.

Short Term Debt

Lakeland has included a 4% short-term debt component as part of its proposed capital structure and is proposing a short-term debt rate for the 2009 Test year of 4.47% in

accordance with the letter from the Board of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications, consistent with the Board Report.

The Board will update the short-term debt rate in early 2009 for rates effective May 1, 2009. However, Lakeland has not indicated whether it has adopted the short term debt rate without prejudice to any revised rate that may be adopted by the Board in early 2009.

Board staff invites Lakeland to indicate to the Board whether it will adopt the short term debt rate as revised by the Board in early 2009.

Long Term Debt

Lakeland's current long-term debt is by way of two debt instruments in the amount of $3,487,500 payable to the Toronto Dominion Bank (TD Canada Trust). Lakeland has forecast a long term debt cost of 5.16% for 2009.

The Applicant's weighted cost of debt of 5.16% has been calculated as follows:

Description	Effective Rate	Debt Balance	2009 Interest Cost
Debenture/Loan to Bank	5.41%	$1,162,500	$ 62,891
Debenture/Loan to Bank	5.03%	$2,325,000	$116,948
TOTAL	5.16%	$3,487,500	$179,839

Board staff note that Lakeland's proposed long-term debt rate appears to be compliant with the Board Report.

Common Equity

Lakeland is proposing a return on equity ("ROE") rate for the 2009 Test year of 8.57%, in accordance with the Board's letter of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications, consistent with the Board's Report. The Applicant has confirmed that its use of an ROE of 8.57% is without prejudice to any revised ROE that may be adopted by the Board in early 2009.

Lakeland believes that the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Board staff notes again that Lakeland's proposal appears to be consistent with the Board Report.

OM&A Costs

Background

Lakeland has applied for a forecast total OM&A excluding depreciation and other taxes of $2,854,047 which is 5.6% ($151,000) higher than 2008 and 14.5% ($360,000) higher than in 2006. A significant increase occurred in 2008; 16.9% ($390,000) over 2007 levels. The following table developed by Board Staff and confirmed by Lakeland in their response to Board staff IR #4, tracks the changes in expenses from 2006:

Lakeland Power Distribution Ltd.

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 11
		2006		2006		2007		2008		2009	
		Board Approved	Variance 2006/2006	Actual	Variance 2007/2006	Actual	Variance 2008/2007	Bridge	Variance 2009/2008	Test	Variance 2009/2006
1	Operation	94,205	168,384	262,589	-65,128	197,461	26,312	223,773	-99	223,674	-38,915
2			*178.7%*		*-24.8%*		*13.3%*		*0.0%*		***-14.8%***
3	Maintenance	621,624	-92,584	529,040	63,976	593,016	242,263	835,279	91,764	927,043	398,003
4			*-14.9%*		*12.1%*		*40.9%*		*11.0%*		***75.2%***
5	Billing & Collections	610,994	41,759	652,753	-46,586	606,167	40,944	647,111	8,026	655,137	2,384
6			*6.8%*		*-7.1%*		*6.8%*		*1.2%*		***0.4%***
7	Community Relations	15,320	12,045	27,365	-9,755	17,610	-9,143	8,467	2,788	11,255	-16,110
8			*78.6%*		*-35.6%*		*-51.9%*		*32.9%*		***-58.9%***
9	Administrative and General Expenses	1,268,289	-246,385	1,021,904	-123,881	898,023	90,129	988,152	48,786	1,036,938	15,034
10			*-19.4%*		*-12.1%*		*10.0%*		*4.9%*		***1.5%***
11	**Total OM&A Expenses**	**2,610,432**	**-116,781**	**2,493,651**	**-181,374**	**2,312,277**	**390,505**	**2,702,782**	**151,265**	**2,854,047**	**360,396**
			-4.5%		-7.3%		16.9%		5.6%		***14.5%***
	Combined O&M (lines 1 & 3)	715,829	75,800	791,629	-1,152	790,477	268,575	1,059,052	91,665	1,150,717	359,088
			10.6%		*-0.1%*		*34.0%*		*8.7%*		***45.4%***

Lakeland explained the increase from 2006 to 2008 in the response to SEC Supplemental IR #1. In that response, the cost drivers were identified, and the primary cost drivers, as can be seen in the following table gleaned from the response, are salaries, wages and benefits, tree timing, and regulatory expenses.

		Col. 1	*Col. 2*
		$,000	**%**
1	Salary, Wages, Benefits	215	59.9%
2	Incremental Tree Trimming	105	29.2%
3	Regulatory Expense/Rate Application	50	13.9%
4	Distribution Station Maintenance	30	8.4%
5	Increased PCB Testing	10	2.8%
6	Pension Cost to Regulatory Assets	19	5.3%
7	ESA Fees	41	11.4%
8	Truck Expense/Fuel	10	2.8%
9	Insurance	9	2.5%
10	Bankruptcy (2006)	-30	-8.4%
11	Contamination Clean-up	-40	-11.1%
12	GIS Mapping of System	-60	-16.7%
13	**Total**	**359**	

With regard to Salary, Wages and Benefits, Lakeland provided detailed compensation information supporting the $215,000 increase in response to Board staff IR #10. According to this schedule, both employee count and average yearly base salaries increases from 2006 to 2009 forecast. The number of FTE's was 13.3 in 2006 and 16 in 2009. The average base wage was $54,649 in 2006 and $61,301 in 2009. Lakeland stated in response to Board staff IR #5, that the large increase in salaries was due to filling vacancies at higher competency levels.

With respect to tree trimming, the Lakeland state at Exhibit 4/Tab 2/Schedule 3/p4 that due to storms, financial resources were diverted from tree trimming to storm damage work. A new tree trimming plan based on a seven year cycle was instituted in 2007.

Regulatory expenses for 2009 are $151,000 before amortization of one time costs. [Response to Board staff IR #7] Lakeland determined an amount to be collected by way of amortization in two steps. First it increased the $123,000 of one-time costs in 2009 with a carry forward of $2,119. Then this total of $125,119 is spread over three years, 2009-2011 in three equal amounts of $41,706.33. Board staff remains unclear on the nature of the carry forward of $2,119. Board staff submit that Lakeland address this in their reply submission. Board staff further submit that Lakefront should address whether or not this amount should be amortized over 4 years to coincide with the now four year Incentive Rate Mechanism (IRM) cycle (cost of service plus 3 years IRM).

Lakeland states that it does not have costs for converting to International Financial Reporting Standards (IFRS) in its forecast. However, in response to Board staff supplemental IR#1, the Applicant provided a break down of an estimate of $120,000 for conversion costs that would be incurred over 2009 and 2010. $110,000 in conversion costs would be incurred in 2009, and the remaining $10,000 in 2010. Board staff submit

that Lakeland address how they would treat these costs for rate making purposes if they expect that they will be incurred.

Board staff submits that the while Lakeland's explanation of the cost drivers from 2006 to 2009 seem reasonable, the overall increase from 2006 to 2009 in OM&A is 14.5% or an average of 3.6% per year. In response to Board staff IR #6e requesting Lakeland to identify any programmes specifically aimed at productivity and efficiency improvements, Lakeland pointed out the need for hiring resources to meet workload, and that the tree trimming program would be an operational improvement.

PILs

Background

In the pre-filed evidence, Lakeland claimed a total PILs expense of $390,132.

Discussion and Submission

The claimed PILs amount was reduced to $342,620 as a result of the response to Board staff supplemental IR#7 that questioned the use of a higher tax rate in the income tax calculation.

Calculations by Board staff indicate a total PILs expense of $319,113 as compared to the revised amount claimed by Lakeland of $342,620. Board staff followed the established methodology and guidelines in use since 2001. The guidelines were reiterated in the Board's 2006 Electricity Distribution Rate Handbook, Chapter 7, and in the accompanying PILs model for the 2006 applications. Using the Board's methodology, the regulatory net income can be calculated using the following formula: Rate Base multiplied by Deemed Equity Percentage multiplied by Deemed Rate of Return on Equity (Rate Base X Equity% X ROE%). The resulting starting point is $575,165 for the PILs calculation.

The Ontario component of the blended income tax rate varies based on taxable income thresholds of $500,000 to $1,500,000. As taxable income increases towards $1,500,000 the income tax rate increases from the minimum rate of 5.5% until the maximum rate of 14% is reached.

The difference in the two amounts exists due to the fact that Lakeland's starting point to calculate PILs expense is utility income before taxes of $965,096. This amount was

derived from a revenue deficiency exhibit[2] that calculates an incorrect deficiency. When this deficiency was added to the 2009 test year revenue, it increased taxable income, and resulted in a higher income tax rate than the Board's guidelines would indicate.

In 2008 EDR, applicants were instructed by the Board to submit the draft rate order based on revenue requirement. Similar types of errors in deficiency calculations were present in the 2008 applications.

Board staff submit that Lakeland should calculate the PILs expense using the appropriate starting point, and gross-up methodology, as found in the Board's 2006 Application Model and Handbook when it prepares its 2009 draft Rate Order.

Cost Allocation and Rate Design

Customer Classes

Lakeland proposes to continue with the same customer classes that are currently approved. There is a single General Service class with demand above 50 kW, and there are no customers with demands larger than 3000 kW. Board staff submits that this classification of customers is reasonable.

Revenue to Cost Ratios

Background

Lakeland filed its Informational Filing (EB-2006-0247), which gives an indication of the revenue to cost ("R/C") ratios with the existing rate structure. The results are shown in the first column in the Table below.

In response to VECC IR #7c and VECC supplemental IR #6, Lakeland provided an alternative run of the cost allocation model that reflects the removal of costs and revenues associated with $57,567 of transformer ownership allowance. The resulting R/C ratios are found in the second column below.

Lakeland's application includes a re-balancing of class revenues to better reflect the results of the cost allocation model. The proposed R/C ratios are shown in the third column. The proposed ratios pertain to 2009 only.

[2] Exhibit 7/Tab 1/Schedule 1

For convenience, the range of ratios for each class from the Board's policy document (Cost Allocation for Electricity Distributors" November 28, 2007) is shown in the final column of the table.

Revenue to Cost Ratio [%]

Customer Class	Informational Filing Run 2	Response to VECC IR Supplementary # 6	Application: Exhibit 8/Tab1/ Schedule 2	Board Policy Range
Residential	98.53	99.85	100.00	85 – 115
GS < 50 kW	95.53	96.90	100.00	80 – 120
GS ≥ 50 kW	147.15	148.99	122.84	80 – 180
Street Lights	16.95	17.29	50.24	70 – 120
Sentinel Lights	24.54	24.99	52.70	70 – 120
USL	67.27	67.02	81.25	80 – 120

Discussion and Submission

The proposed ratios for Streetlighting and for Sentinel Lighting go nearly two thirds of the distance from the status quo to the lower boundary of the policy range. The proposed ratio for Unmetered Scattered Load (USL) goes from outside the range to within the range.

The proposed movement to 100.0% for the Residential and GS < 50 kW classes requires re-balancing increases respectively of approximately 1.5% and 5.6% relative to the general change in the revenue requirement. If the starting point is accepted as being the adjusted ratios per the VECC interrogatory, these increases would take the ratio beyond the 100% point. Board staff submits that the reasoning underlying the VECC correction is valid, insofar as the cost allocation model does have an internal inconsistency in how it handles the "cost" of the transformer ownership allowance. However, staff submits that impact of the correction is very small, and cost allocation results are not so precise that Lakeland should change its proposal for re-balancing class revenues.

Lakeland has suggested that the proposed ratio for Streetlighting is suitable for 2009, and that further consideration of the subject may be pending that would affect whether the ratio should be increased further in subsequent years. (Ref: Exhibit8/Tab1/Sch2/p. 5). Lakeland does not mention whether the same reasoning would apply to Sentinel Lighting. Board staff submits that it would be reasonable to continue with the re-balancing trend in the following years, at least to the point that the ratios for Streetlighting and Sentinel Lighting would be brought to 70%.

Monthly Fixed Charges

Background

Lakeland proposed to maintain the fixed/variable split constant for all classes, except for Residential where it proposed to increase the proportion of revenue from the volumetric rate and decrease the proportion from the Monthly Service Charge. The ratios listed in the Application (Ref: Exhibit9/Tab1/Sch1/p. 3) are net of Smart Meter and LV rate adders. The ratios including adders are slightly different and the proposal would maintain the adders nearly unchanged (Response to Board staff IR # 35c).

Discussion and Submission

The Monthly Service Charge approved for the two General Service classes in 2006 were higher than the amounts calculated as the ceiling in Lakeland's subsequent cost allocation study. The difference is minor in the case of the General Service < 50 kW class, but substantial in the case of the General Service > 50 kW class. (Response to SEC IR #15). Staff submits that the proposal to maintain the fixed/variable split in this situation is reasonable, pending the completion of on-going study of rate design issues by the Board.

Rate Design – Unmetered Scattered Load

Background

Lakeland proposes an increase in the Monthly Service Charge from $14.89 to $38.78 per connection, and an increase in the volumetric rate from $0.0097 to $0.0203 per kWh. The comparable proposed rates for the General Service < 50 kW class are $39.13 (net of Smart Meter adder) and $0.0118 per kWh.

The rate increases to the USL class are 160% and 109% for the fixed and volumetric rates respectively. The rate increase would change the revenue to cost ratio from 67% to 81% as noted above.

Lakeland found that its customer-related costs in the Cost Allocation study were higher for a USL (per connection) was higher than for a General Service (per customer), and attributed this to a default weighting factor in the model. By changing a weighting factor, it found that the cost per connection was closer to what might be expected, at $18.08 per connection compared to $24.62 per General Service customer (Response to Board staff IR #31).

Discussion and Submission

Board staff submits that it would be anomalous to charge nearly as much per connection and nearly twice as much per kWh to the USL class, compared to the GS < 50 kW class. The rationale may be rooted at least in part in the cost allocation model, with respect to the Monthly Service Charge, but there does not appear to be a rationale for the divergence in the volumetric charges. Staff submits that Lakeland should reconsider its rate design, and should propose rates for the USL that would be comparable to the General Service < 50 kW class rate (perhaps a Monthly Service Charge near 75% as submitted in the interrogatory together with a volumetric charge closer together).

Low Voltage Costs

Background

Lakeland has requested recovery of low voltage costs of $656,843. It has allocated this cost to its customer classes in proportion to its revenues from the Retail Transmission Service Rates, and has calculated rate adders that would recover these amounts from the respective classes (Ref: Exhibit9/Tab1/Sch1/p. 8).

The estimated cost is comparable to 2007 actual cost of $613,233 and the 2008 pro forma amount of $666,534. These amounts are based on the approved monthly Hydro One Low Voltage charges that were in effect during those years. The 2009 forecast is based on the four monthly LV charges that Hydro One had applied for in its application EB-2007-0681:

- service charge of $188 at each of 10 delivery points;
- meter charge of $553 at each of 10 delivery points,;

- $0.58 per kW for Common ST Line;
- $1.24 per kW for Low Voltage Distribution Station.

Discussion and Submission

Board staff submits that the Lakeland application is consistent with policy and is well supported by the evidence. Staff also notes that the LV rates ultimately approved by the Board were some 4% lower than those assumed in Lakeland's cost forecast and that Hydro One has since applied for an update of the LV rates effective May 1, 2009 (EB-2008-0187).

Board staff submits that the best forecast of Lakeland's costs would be to assume the Board's approval of the Hydro One application to update LV rates. Board staff further submits that it would be beneficial for Lakeland to revise its cost forecast, to repeat its cost allocation and calculation of rate adders, and to submit the latter with its Reply Submission. For convenience, staff notes that the rates applied for in Hydro One's application are service charge $184.28, meter charge $537.18, Common ST Line $0.545 per kW, and LVDS $1.212 per kW. (Ref: EB-2008-0187/Exhibit E/Tab 1/Schedule 2/p. 2 updated January 30, 2009)

Retail Transmission Service Rates

Background

Lakeland received approval of Retail Transmission Service Rates ("RTSR"), effective May 1, 2008, that were lower by 18% and 5% than the previous rates. These change reflected the changes in Uniform Transmission Rates that had come into effect in November 2007. In the initial application, Lakeland did not propose to change its RTSRs. (Ref: Exhibit9/Tab1/Sch3)

Lakeland provided data on monthly charges from Hydro One and monthly billings to Lakeland's customers 2006-2007. It then estimated what the charges would have been if the host distributor had charged its 2008 rates (which have since been approved final effective May 1, 2008). Starting from these costs, Lakeland calculated a set of retail rates that (with the new Total Loss Factor) would have generated revenue equal to the wholesale charges. Using these hypothetical rates and loss factor, Lakeland provided a calculation of the difference between its actual costs and what its revenue would have been for the period for the period June – December 2008 (Response to Board staff

supplementary IR #10b). There was a disparity remaining of 8% Network and 3% Connection. This disparity is considerably smaller than the variances experienced during the 2006-2007 period.

In a related calculation, Lakeland provided estimates of the 2009 total cost of transmission service for inclusion in its working capital allowance. (Ref: Exhibit2/Tab4/Sch1) Board staff submits that an update of this estimate should be based on the Hydro One RTSRs as they pertain to embedded distributors (EB-2008-0187). Staff notes in particular that the forecast cost of Connection Service is higher than the 2007 actual cost by about 12% whereas the rate applied for is lower than the rate in 2007 by about 4%.

Discussion and Submission

Board staff notes that Hydro One received approval of RTSRs that would apply to Lakeland effective May 1, 2008. However, Hydro One has since applied for new rates effective May 1, 2009. (EB-2008-0187). Hydro One's changes would mirror the changes in the Uniform Transmission Rates already approved. If this Hydro One application for new rates were approved, an embedded distributor such as Lakeland would be charged a Network rate 11.4% higher and a Connection rate 5.9% higher than is now the case.

Lakeland calculated a set of RTSRs in its responses to Interrogatories, for example, response to Board staff supplementary IR #10a, that would come close to balancing revenues with the cost of the host distributor rates now in place. Board staff suggests that Lakeland might make the assumption that the Hydro One application is approved, and that it might submit for approval a set of RTSRs – with Network increased by approximately 11.4%, and Connection increased by approximately 5.9%.

Board staff points out that the adjusted rates calculated by Lakeland still had a disparity of 8% Network and 3% Connection, based on the partial year June – December 2008. Staff is not able to determine whether any part of this disparity is atypical or seasonal. If the calculation is indicative of a typical year, then Lakeland might wish to submit rates that would be about 4% higher for Network rates (i.e. 11.4% less 8% disparity). Following the same reasoning as suggested for Network costs, staff suggests that an increase in Connection rates (i.e. 5.9% less 3% disparity) compared to those provided in the interrogatory responses.

Specific Service Charges

Lakeland will continue with all of its currently approved Specific Service Charges. Board staff submits that these charges are reasonable, and that Lakeland's forecast revenue from the charges is also reasonable.

Transformer Ownership Allowance

Lakeland has applied to continue the currently approved allowance of $0.60 per kW. Board staff submits that this is reasonable.

Loss Factors

Background

Lakeland has proposed an increase to its total loss factor ("TLF") from the current approved 1.0428 to 1.0614 for secondary metered customers < 5000 kW. The latter amount is a corrected amount submitted in response to Board staff IR #25a replacing the amount 1.0654 submitted originally. The corresponding approved TLF for primary metered customers is currently 1.0323. A corrected amount was not provided in the response mentioned, but would be 1.0514. Lakeland does not seek approval of TLFs for customers larger than 5000 kW.

Lakeland provided a five-year history of its Distribution Loss Factor ("DLF"), which averages 1.0315. It provided a five-year history of its Supply Facility Loss Factor ("SFLF"). (Ref: Exhibit4/Tab2/Sch9/Table 2), which shows an average value of 1.029.

Discussion and Submission

Lakeland is an embedded distributor. Board staff notes that the TLF approved for Hydro One at embedded delivery points is 1.034, which determines the SFLF for an embedded distributor, and Lakeland elaborated that approximately 12% of its power requirement comes from an embedded hydro generation source. The blended outcome is an SFLF of 1.029.

Staff submits that Lakeland's DLF is reasonable, and that the proposed TLFs are supported by the evidence. The increase of nearly 2% is in the nature of a correction to the previously approved factor.

Deferral and Variance Accounts

Background

Lakeland did not request disposition of any deferral or variance accounts.

Lakeland filed information on its balance in account 1590 'Recovery of Regulatory Asset Balances' as of the end of 2007 (Response to Board staff IR #37) together with a continuity schedule showing un-audited credits during 2008 (Response to Board staff IR #38a). The balances total approximately $142,000 without RSVA accounts, and $152,000 including RSVA accounts. Lakeland calculated illustrative rate riders that would result from disposing of accounts in two scenarios: 1) deferral and variance accounts except for RSVA accounts and accounts associated with Smart Meters, PILs and CDM, and 2) the same accounts plus the RSVA accounts. (Response to Board staff IR #38d).

Discussion and Submission

Board staff notes that the balances in Lakeland's accounts, when taken in aggregate, are proportionately quite small, and the resulting rate riders to dispose of the balances would be fairly small. Individual accounts have comparatively large balances. In particular, account 1588 'RSVA – Power' has increased steadily over a number of years. Also, the transmission RSVAs 1584 and 1586 have grown steadily in the offsetting direction. This trend should be arrested with the adjustments suggested above concerning Retail Transmission Service Rates.

Board staff would support disposition of most or all deferral and variance accounts (appropriate for current disposition) without creation of a specific rate rider (as the net result would not warrant a new 2009 rate rider).

Revenue Offsets

Lakeland's forecast of revenues (Exhibit3/Tab3/Sch1) that offset the requirement for distribution rate revenue decreased by approximately $100,000 from the 2007 actual amount. Board staff submits that the explanation of the decrease is acceptable (Response to Board staff IR #28) and that the forecast of Other Distribution Revenue is reasonable.

- All of which is respectfully submitted -