ESTABLISHING 2006 ELECTRICITY DISTRUBTION RATES

COMMENTS OF AIKEN & ASSOCIATES

General Comments

- Aiken & Associates is concerned with the amount of time between the filing of the cost of service evidence by the utilities and the implementation of rates nearly 1 year later. In the gas sector, the utilities often provide a “blue page” update to their evidence to reflect changes from its original filing. This essentially results in a second filing. This should be avoided for the electric utilities as it is a significant burden on the utility, the regulator and the intervenors. A possible solution to this is a staggered filing by the utilities and a faster approval of rates by the Board for these staggered filings.
- The use of written hearings for the majority of the utilities should expedite the process and allow the Board to approve rates quicker for these utilities.
- Board Staff should consider putting together a draft cost of service model (spreadsheet) and hold workshops with utilities and intervenors as soon as possible. This will enable utilities to get a feeling of the information needed to complete the cost of service filing. Intervenors can assist the utilities by letting them know why type of supporting evidence they would envision as being useful in minimizing the time and costs associated with the actual rate hearings.

Comments on Identified Issues

The following comments on the potential issues identified by Board Staff are based on the experience of Aiken & Associates in the preparation of cost of service evidence over a number of years for natural gas distributors, an electricity transmitter, and electricity distributors in Ontario. Aiken & Associates has prepared evidence and testified in 7 cost of service applications for a natural gas distributor, 1 cost of service filing, including an oral hearing for an electricity transmitter and 3 cost of service filings for electricity distributors, including one that is currently undergoing a written hearing.

The following comments are based on the tight timetable that is proposed for the cost of service filings for 2006 rates and contemplates a 2007 filing that incorporates cost allocation changes.

Issue 1 – Use of Comparators and Cohorts

- the use of comparators may be useful in identifying differences among utilities that may appear to be similar, however, the comparators should not be used to determine the cost of service revenue requirement

- the development of comparators and cohorts could be shifted to a generic and parallel process from the cost of service filings – this would simplify the cost of service process

Issue 2 – Test Year for Establishing Rate Base/Revenue Requirement

- a forward test year would be better for utilities that are experiencing positive or negative growth, as it offers the utilities an opportunity to reflect the most recent information (whether changes in rate base, operating costs and/or load forecasts)
- an historical test year would be find for utilities not experiencing any substantial growth (positive or negative)
- it should be up to the utility to decide how it wants to approach this issue
- a combination test year (historical and forecast) should be avoided as this approach will result in many discontinuities. For example, an historical test year updated only for capital expenditures to update rate base would result in depreciation costs inconsistent with the new rate base, the capital would not equal rate base, interest costs associated with the historical level of debt would be less than under the new level of debt on a deemed basis, the income tax calculation would utilities lower interest costs, the level of revenue would not reflect the impact of adding customers related to the capital expenditures, etc. Intervenors would likely follow up on these discontinuities as they could have substantial impacts on the revenue requirement and the subsequent rates.

Issue 3 – Load Forecast

- there does need to be a generic method for load forecasts; a simple extrapolation methodology based on number of customers and average load per customer could be utilized
- different methodologies could be used by different utilities
- utilities need to provide evidence as to why their forecasts should be accepted by the Board and other parties
- what weather assumptions should be used in the forecast (i.e. heating degree days, cooling degree days, etc) (see Weather Normalization below)
- a load forecast (kW, kWh) for each rate class is required in order to properly recover the revenue requirement from customers. In other words, without a load forecast, rates cannot be determined that will recover the revenue requirement.

Issue 4 – Test Year Adjustments

- adjustments to historical or future test year data will need to be supported by credible evidence
- adjustments for inflation, productivity, etc. do not need to be complex
- all adjustments should be justified by supportable evidence

Issue 5 – Weather Normalization

- if historical data is used, the revenues (and loads) should be normalized to a standardized "normal" weather (i.e. heating degree days, cooling degree days, etc.)
- if 2004 data is used as the historical year, should an adjustment for the leap year be made?
- One methodology for weather normalization for use across the province may not be appropriate
- Normalization could be as simple as calculation actual use per HDD or CDD and then adjusting to the normal level of HDD or CDD

Issue 6 – (Maximum) Return on Equity for 2006 Electricity Distribution Rates

- if the issue of business risk changes are raised there is likely to be intervenor evidence to suggest that the level of business risk has fallen – can be impacted, for example, by the increased recovery of the revenue requirement through fixed charges that automatically reduce the impact of weather risk on the business
- OEB has recently reviewed the formula and determined no changes were necessary
- How will the multi-year forecast of long Canada bond interest rates be determined? In the gas sector, rates are based on one year forward forecast from Consensus Economics – however, this forecast only goes out 12 months
- Since we are dealing with 2006 rates specifically for this proceeding, a one year long Canada bond yield forecast would be adequate
- A number of utilities are not-for-profit – how does a return on equity fit into the calculation for these not-for-profit utilities (In the RP-2001-0036 Decision with Reasons for Five Nations Energy Inc., dated April 24, 2002, the Board directed FNEI to use the Times Interest Earned Ratio ("TIER") rate-making mechanism for calculating the amount to be included in its revenue requirement in future rate hearings. This mechanism allows a utility to earn between 2 and 3 times the interest that it expected to incur on the debt that financed its rate base. This TIER mechanism is widely used in U.S. jurisdictions for non-profit utilities.)

Issue 7 – Debt/Equity Structure

- the actual capital structure could be utilized, but the actual equity component should be capped at the deemed level
- use of the deemed capital structure is simpler to administer – i.e. if using an adjusted historical or future test year, the projected debt level needs to be estimated
- the current rate handbook contains four sizes of utilities for the deemed equity and debt ratios with the smallest group for utilities with a rate base of less than $100 million – should this be reviewed with the goal of establishing a small

rate base group (perhaps with a rate base of less than $25 million) with a different deemed common equity and debt ratio?
- A deemed component for short-term debt should be established with an order of magnitude of the working cash component of the total rate base

Issue 8 – Debt Rate/Cost of Capital
- the actual cost of debt should be used where available
- a short-term debt rate should be used on the short-term debt component – the rate should be set based on the prime business rate plus a premium that grows for the smaller the utility rate base. For example, the large utilities may be able to obtain short-term debt at or below prime, while the smallest utilities maybe be required to pay prime plus 200 basis points
- substantial amounts can accumulated in the deferral/variance accounts – there is a need to ensure that the interest cost on these accounts is managed – propose that the interest rate on the balance in deferral/variance accounts be based on the actual prime interest rate at the beginning of each quarter (plus the basis points above prime for each group of utilities) – this ensures that the cost of the deferral accounts to be paid by ratepayers and the utility closely match actual rates

Issue 9 – Depreciation Rates
- current depreciation rates appear to be the same across most utilities – this may be inappropriate – many utilities may have unique circumstances, such as the age of their current assets, in determining future depreciation rates
- depreciation rates are calculated based on a number of inputs including the total service life of the assets in each category, the weighted average age of the current assets in each category, the salvage value or costs and the total cost, accumulated depreciation and net book value of the current assets in each category
- generic province wide estimates should be obtained for the total service life of assets and utilities should have the option of deviating from these estimates if they have specific verifiable reasons for the difference
- the other inputs into the depreciation calculation are likely to be unique to each utility (eg. weighted average age of current assets, total cost, accumulated depreciation, NBV, salvage value)
- utilities should be free to incorporate new depreciation rates into their 2006 revenue requirement (with the accompanying review of the depreciation study by the OEB and intervenors)
- depreciation studies should be completed in time so that the changes in depreciation costs in the revenue requirement can be incorporated into the 2007 rates application that will include cost allocation changes
- The OEB encourages (requires) the natural gas utilities to update and file new depreciation studies approximately every five years. These studies are

reviewed by the Board and intervenors and the Board approves or denies changes to the various depreciation rates by asset category

- A delay in implementing new depreciation rates is partially offset by the impact on accumulated depreciation, and therefore rate base. For example, a higher depreciation rate in the test year will result in a lowering of the rate base and the associated return on capital.
- One option that would significantly simply depreciation costs and eliminate the need for depreciation studies would be to move all utilities to a declining balance approach with rates set at the rates used for CCA calculation purposes

Issue 10 – Transfer Pricing and Shared Corporate Services

- This is a very contentious issue in the gas sector as the possibility exists that utilities can move profits out of the regulated entity into an affiliated company at the expense of ratepayers
- Debt from affiliated companies has received significant scrutiny from the OEB in the gas sector. Utilities will have to provide evidence that the rate and terms and conditions (for example, early payment penalties) are competitive with financing that could have obtained from third parties
- If the utility provides a service to an affiliate, evidence would be needed that it is charging a cost-based price for this service and not providing the affiliate with a subsidy at the expense of the ratepayers

Issue 11 – Low Voltage and Wheeling Costs

- it would appear that the simplest approach to these costs that are incurred by a subset of the utilities would be to treat the costs as a pass through with the establishment of variance accounts in the same way as the transmission costs are dealt with
- the load forecast would be important in determining the rate to be charged customers on a forecast basis to cover the costs incurred by the utilities – some rate design/cost allocation may be required to allocated the costs to the various rate classes and determine the appropriate methodology of recovery (i.e. fixed/variable)

Issue 12 – 2006 Taxes / PILS

- corporate income tax, capital taxes and property taxes (if applicable) are all part of the revenue requirement
- regulated utilities should be taxed, for regulatory and revenue requirement purposes, on a stand alone basis (the following except is taken from the EBRO 496 Decision with Reasons for Natural Resource Gas Limited and is dated August, 20, 1998:
- “The Board notes that the avoidance of cross-subsidization between regulated and non-regulated activities of a company or group of companies is a key principle in regulation”

- "…, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the federal capital tax to be included in NRG's cost of service."
- "As previously stated, the Board is a strong proponent of the principle of avoidance of cross-subsidization. Consequently, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the income tax to be included in NRG's cost of service."
- "The Board finds that, since NRG should be entitled to the federal Small Business Deduction, this deduction must be included in the calculation of income tax for regulatory purposes …."
- Tax rates, deductions, etc. should be based on current estimate for 2006
- Calculation of taxes should be done consistent with that used for regulatory purposes in natural gas regulation in Ontario (i.e. future or deferred taxes should not be considered in the regulatory approach)
- How should the Capital Cost Allowance (CCA) schedules be determined (i.e. what is the appropriate UCC starting point for the 2006 deduction calculation)
- Rate base can be used as a proxy for net paid up capital in the calculation of capital taxes, significantly reducing the amount of data needed to calculate these taxes

Issue 13 – Definition of Distribution Rate Base

- level of detail (asset categories) should be consistent with account procedures handbook – need consistency to carry forward as well to cost allocation model
- utilities should be given a new asset category to include contributions to categories not in distribution rate base – an appropriate depreciation rate may need to be determined
- natural gas utilities are allowed to include contributions made to upstream transportation assets of other utilities in their rate base calculation
- allocation of shared assets between regulated and non-regulated functions should be done on a utility by utility basis as these arrangements are not likely to be standardized across the province
- rate base for natural gas utilities includes a reduction for customer deposits – this should be added for consistency in the regulation – the interest paid on customer deposits is recorded as an O&M expense and included in the revenue requirement (see No-Cost Capital below)

Issue 14 – Rate Base Measurement Date(s)

- is the difference between calendar year and rate year a problem, or just a timing difference?
- Could rate implementation be delayed to January 1, 2007? This would provide utilities with more time to file their cost of service evidence and would also allow for a staggered filing so as to not overwhelm the Board, Board Staff and intervenors

- The calculation of the rate base using the opening and closing balance for the year is recommended as it is simpler (i.e. does not require the forecasting or adjustment of property plant and equipment on a monthly basis for capital expenditures required if the average of monthly values is used) – there is little difference in the quantum of rate base for most utilities between the two methodologies
- The end of period value should not be used for rate base as this introduces a bias into the revenue requirement calculation – interest costs, income taxes, capital taxes, etc. can all be affected

Issue 15 – Working Capital Component of Rate Base

- lead-lag studies should be performed for inclusion in the 2007 rates filing (the filing that includes cost allocation changes)
- in the meanwhile utilities should be encouraged to perform a lead-lag study for the cost of power in the 2006 filing as the cost of power is a major cost to utilities. This can be done relatively quickly and simply, calculating the revenue lag (service lag + billing lag + collection lag) based on an analysis of accounts cost of power expense lag based on the payment dates
- the GST lag associated with the cost of power payments should also be done
- a cost of power forecast will need to be done whether or not a lead-lag study is complete – this requires a load forecast for the individual utilities and forecast for the cost of power and the various pass through charges (transmission, etc.)

Issue 16 – Capitalizing Expenses

- utilities may have valid reasons for different capitalization policies
- one approach may not be appropriate for all utilities
- utilities should be prepared to present evidence to support their approach as reasonable

Issue 17 – Capital Projects

- it may be difficult to use trendlines to review capital expenditures and projects can be “lumpy”
- in the gas sector, capital projects costing $500,000 or more are reviewed in more detail for Union Gas (rate base of $3 billion) and capital projects costing $15,000 or more are reviewed in more detail for NRG (rate base of $9.5 million)
- there should be a level of capital projects that are reviewed in more detail based on an individual utilities rate base, for example, any project that exceeds 0.25% of total rate base
- utilities should be prepared to provide their policies on vehicle and equipment replacements

Issue 18 – Contributed Capital

- a separate schedule should be provided that shows that pre-2000 contributed capital, along with a continuity schedule that shows the net assets remaining from this pre-2000 contributed capital in the 2006 year for which rates are being set

Issue 19 – No-Cost Capital

- customer deposits should be treated as they are in the gas sector and used to reduce rate base. Interest cost on the deposits is an O&M expense.
- Pre-2000 contributed capital that is included in rate base should be included as no-cost capital

Issue 20 – Rate-Setting Treatment of Capital Gains

- the same approach should be followed for electric utilities as for gas utilities
- depreciable property is dealt with through adjustments to gross plant and accumulated depreciation
- in recent Enbridge and NRG Decisions the Board has determined that capital gains on non-depreciable property (such as land, etc.) should be shared 50/50 between shareholder and ratepayer

Issue 21 – Distribution "Wires Only" Expenses

- priority should be given to updating the Uniform System of Accounts and the Accounting Procedures Handbook to make these the basis for cost of service filing and the cost allocation model

Issue 22 – Post-Retirement Benefits and Pensions

- utilities must provide sufficient evidence in support of these costs, which can be significant – they can draw much scrutiny from both intervenors and the Board

Issue 23 – Site Restoration and Removal Costs

- How will utilities forecast these costs for the cost of service test year?
- How should any costs incurred prior to the cost of service test year (i.e. while under PBR) be treated?
- How will any such costs included in 2006 rates be removed once the costs have been incurred under a subsequent PBR horizon?

Issue 24 – Insurance Expense

- this can be a significant expense for utilities
- costs can be influenced by level of coverage, deductibles, etc

- what is the appropriate reserve level for those utilities that self-insure?
- What is the appropriate rate treatment for future costs that may not be covered by insurance?

Issue 25 – Bad Debt Expense

- each utility has a differing mix of customers and their own unique history of bad debts
- the bad debt expense should be based on the utilities' own unique experience

Issue 26 – Employee Compensation and Staffing

- as a major expense category, this expense will attract scrutiny
- utilities should be prepared to provide historical data (number of employees, wages/employee, benefits/employee, etc) to support its forecast in the test year of these costs
- bonus/incentive plans will need to be explained so the Board can determine who benefits from them and subsequently who should pay for them

Issue 27 – IT Costs

- again, a potential for a major cost – may attract much scrutiny, as it has for the 2 large gas utilities
- evidence should be detailed on the costs included

Issue 28 – Advertising, Entertainment, Charitable/Political Contributions, Employee Dues, Research & Development

- charitable donations are not recoverable through the revenue requirement of gas utilities, a consistent approach should be applied to electric utilities
- political donations are not recoverable through the revenue requirement of gas utilities, a consistent approach should be applied to electric utilities

Issue 29 – Specific Service Charges

- specific service charges may be impacted by the cost allocation model, so is it appropriate to deal with these charges prior to properly costing them?
- There should not be a single charge for each service across Ontario – the unique characteristics of utilities may mean that some services cost more to provide in different geographical areas, in different customer density areas, etc.

Issue 30 – Unmetered Scattered Load
Issue 31 – Time-of-Use Rates
Issue 32 – Fixed/Variable

- given the large undertaking of utilities to file cost of service information, it would be preferable to defer all rate design issues until after the cost allocation studies are completed.
- The fixed/variable determination should especially be deferred as there exists the potential to shift the costs from variable to fixed, or vice-versa, only to find a year later that the shift should now go in the opposite direction, causing confusion among customers

Issue 33 – 2006 Rate Mitigation

- rate mitigation should only be utilized in exceptional cases
- if 2006 rates are to be used as the basis for a second generation of PBR, the 2006 rates need to be implement in full without any type of phase-in under the PBR period in the future

<u>Comments on Additional Issues</u>

Aiken & Associates has a few comments on the additional issues that were identified at the stakeholder meeting on July 6 and 7:

Ancillary Revenue Treatment

- any ancillary revenue should be used to reduce the overall revenue requirement of the utility
- ancillary revenue is at least partly driven by the use of regulatory assets and thus ratepayers should benefit from this revenue

Earnings Sharing

- under cost of service regulation, there is no earnings sharing.
- Utilities are at risk from any variance in costs, capital expenditures, taxes, etc, from that forecast and included in the revenue requirement
- If any earning sharing is used, the return on equity should be reduced as the risk the company has been reduced

DSM

- any DSM costs and assets should not be included in the calculation of the revenue requirement, unless there is much more certainty surrounding the DSM issue before the 2006 rates filing is due
- deferral accounts should be utilized for the DSM issues and these accounts should be cleared as soon as clarity in this area is available
- a "lost revenue adjustment mechanism" account should be established to protect utilities from lost revenue related to their own DSM initiatives

SSS Admin Costs and Charges

- this is a cost allocation issue and should be dealt with through the cost allocation model

Rate Year “anniversary” date

- the rates from the cost of service filing should be implemented on January 1, 2007 rather than May 1, 2006
- this would match the rate year with the fiscal year
- this would provide more time for the utilities to complete their cost of service filings

Update APH

- as indicated above, the updating of the accounting procedures handbook should be given priority so that there is an up-to-date platform for the cost of service model and the cost allocation model
- without an updated APH, there exists the potential for a lack of consistency between cost of service filings that will be magnified in the cost allocation filings

Cost Allocation in 2006

- some type of allocation will be required for the 2006 cost of service revenue requirement that will reflect the change in the cost of service and the change in loads for the different rate classes
- significant thought should be given to how a change in the revenue requirement will be recovered from/rebated to the various customer classes