Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

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Ontario Energy Board

Filing Requirements for Transmission and Distribution Applications

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Chapter 1 Overview

This document provides information about the filing requirements for electricity transmission and distribution applications. It is designed to provide direction to applicants, and it is expected that applicants will comply with the filing requirements unless such compliance is not practical or in the public's interest. It is not a statutory regulation or a rule or code issued under the Board's authority. It does not preempt the Board's discretion to make any order or directive as it determines necessary concerning any of the matters raised by the applications filed.

The purpose of this document is to provide information about several filing requirements dealing with electricity transmission and distribution applications. These include:

- Filing requirements for electricity transmission and distribution companies' cost of service rate applications pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the Act), based on a forward test year,

- Filing requirements for the 2nd generation incentive regulation mechanism for electricity distributors pursuant to section 78 of the Act,

- Filing requirements for leave to construct electricity transmission projects under section 92 of the Act, and

- Filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the Act prior to the approval of an Integrated Power System Plan (the IPSP)

- Filing requirements for applications for supplemental 2007 Conservation and Demand Management (CDM) Funding, Recovery of Lost Revenue and Shared Savings

Chapter 2 details the filing requirements for a cost of service rate application based on a forward test year that the Board will require from an electricity transmission or distribution company. Electricity transmission or distribution companies are to use these filing requirements as the basis for filing a forward test year cost of service application. They form the necessary material that should be included in a rate application and an application that fails to provide all of the elements may be considered incomplete and may not be processed until the material is provided. While the basis for the 2006 distribution rates applications was a historic test year, the standard methodology going forward, will be utilizing a forward test year.

This requirement is to be used when an electricity transmitter or distributor is seeking the Board's approval for rebasing its rates. Distributors will be asked to seek those rebased rates over a staggered period, guided by the Board's multi-year electricity rate setting plan. For those distributors not having a base adjustment to rates, an incentive mechanism will be employed. This will be detailed in Chapter 3.

Chapter 3 details the filing requirements for the mechanistic incentive rate adjustment, including the cost of capital to be used, for the years 2007 to 2009. This approach will be used for electricity distributors only when there is no requirement to file a complete cost of service rate application.

Chapter 4 details the filing requirements for the approval of a leave to construct electricity transmission projects under section 92 of the Act for the construction, expansion, or reinforcement of electricity transmission facilities greater than 2 km in length.

Chapter 5 states the filing requirements, prior to approval of the IPSP, for electricity transmission companies for projects under section 92 of the Act and for capital budget approval of transmission projects that will need Board approval as a component of a rate application, under section 78 of the Act. Normally, such capital projects would be able to rely on an approved IPSP for the establishment of such elements as need and cost effectiveness. Prior to an approved IPSP, there are filing requirements that the Board will require to ensure a complete review of the proposed transmission projects. Chapter 5 will be used during the transition period prior to an approved IPSP. The document will be amended as necessary once the first IPSP has been approved by the Board.

Chapter 6 details the filing requirements for an application seeking approval for supplemental 2007 Conservation and Demand Management (CDM) Funding, Recovery of Lost Revenue (LRAM) and Shared Savings (SSM). This Chapter will assist distributors in their applications for additional 2007 CDM funding until other funding is available and to facilitate the filing of applications for LRAM and SSM for CDM programs.

Chapter 2 Filing requirements for electricity transmission and distribution companies' cost of service rate applications, based on a forward test year

2.0 Preamble

Framework

The Ontario Energy Board regulates the electricity transmission and distribution companies using a combination of an annual incentive rate mechanism and a rebasing mechanism. Rebased rates will be set using forecast test year data.

Notwithstanding the above structure, an application to the Board is an application by the regulated company, and not merely a form filling exercise where the view is to provide minimum data. The structured approach in a rebasing filing facilitates reviewing the applications. However, the material presented is the applicant's case and the onus is on the applicant to prove the need for new rates. Therefore, a clearly written application that advocates the need for new rates, complete with sufficient evidence and justification, is essential to facilitate a timely decision, for example, by keeping the interrogatories to a minimum.

While it would be convenient to not file material that it is already on file with the Board, in procedural law, the examination and decision of an application is based solely on the evidence filed in that case. This ensures that all parties to the proceeding have an opportunity to see the evidence and follow the reasons of the Decision. Consequently, all the Filing Requirements must be met by the applicant.

Some information, however, may be of a confidential nature. The Board has developed a Practice Direction on Confidential Filings, EB-2006-0084. These Directions should be followed when applying to the Board and required information is confidential.

For the distributors, recognizing that rebasing may occur every three years, a distributor may consider applying for deferral accounts for capital works during the non-rebasing years to collect the cost of construction.

Process

Notwithstanding a structured approach and standard evidentiary guidelines, the Board recognizes that an important aspect of any case is the uniqueness of the transmitter or distributor and the circumstances surrounding its operation. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's market.

Utilities typically produce budgets by planning on a work basis. This will be the basis for presenting budgets. However, applicants are required to summarize the forecast by USofA accounts together into defined functionalized costs in the cost allocation model for the purposes of cost allocation and comparative analysis.

For distributors, by the time these filing requirements become applicable to applications for 2008 rates, the Board will have completed its review of the cost allocation submissions and identified any subsequent initiatives. The Board expects that these cost application submissions will form the basis of any rate design or cost allocation issues that electricity distributors would submit for consideration as part of their cost of service filing.

Terminology

Corporate cost allocation is an allocation of costs for corporate and miscellaneous shared services from the parent to the utility. This is not to be confused with the allocation of the revenue requirement to rate classes for the purposes of rate design.

Non-core delivery activities are activities that are ancillary to the core purpose of delivering electricity and do not form part of the revenues from rates for delivery (e.g. water meter reading).

Profitability Index ("PI") is the ratio of the discounted revenues anticipated from an investment to the cost of the investment, over the life of the project. This calculation is typically performed by a utility when determining whether there should be a capital contribution from the customer towards the construction of a facility to serve that customer.

Revenue sharing is the sharing of revenues between utility and customer per a formula in a specific programme approved by the Board.

2.1 Introduction

The basic format of the filing consists of the following nine Exhibits:

Exhibit 1 Administrative Documents
Exhibit 2 Rate Base
Exhibit 3 Operating Revenue
Exhibit 4 Operating Costs
Exhibit 5 Deferral and Variance Accounts
Exhibit 6 Cost of Capital and Rate of Return
Exhibit 7 Calculation of Revenue Deficiency or Surplus
Exhibit 8 Cost Allocation
Exhibit 9 Rate Design

These filing requirements are to be used for filing a forward test year cost of service application for transmitters and distributors. Companies should use these filing requirements if they are not filing in accordance to a Board prescribed rate setting methodology such as the second generation incentive mechanism. If any significant element of these filing requirements is not included in the filing, the application may be deemed incomplete and may not be processed until completed.

The OEB has established a multiyear electricity distribution rate setting plan. In the multiyear plan, the Board has outlined when certain policy matters will be addressed. Utilities are advised that those are the appropriate times for policy review and that those reviews should not be conducted in individual rate setting proceedings.

The applicant must include a detailed variance analysis between the Test Year and Bridge Year, and between the Test Year, the Historical Year and the last Board Approved Test Year . This analysis must explain the reasons for the variance, the drivers of the variance and the contribution of each towards the total year over year variance.

The Board's filing requirements have been designed in a manner to isolate the delivery related sufficiency/deficiency separate and apart from the energy related sufficiency/ deficiency. In keeping with that, utilities should provide revenue sufficiency or deficiency calculations net of the electricity cost changes captured in the RSVA's.

Any Section 92 facility application is subject to the requirements of chapters 4 and 5 (see Section 2.3 dealing with capital budgets for projects with the construction commencement in the test year).

The requirements for rate design do not apply to transmitters for their costs are combined with the other transmitters' costs to establish province wide rates. Consequently, only allocated costs to cost classifications as required by the Board need be shown.

Finally, the Board remains cognizant of the large number of interrogatories that the existing process can generate. The requirement of a large number of questions suggests failure of the parties to have a common understanding of the information needs. The Board advises applicants to strategically consider the clarity of the evidence, so that it is understood by parties involved in the process providing them with the information needed to understand the case from their perspective, with the objective of reducing the number of interrogatories.

2.1.1 Key Planning Parameters

The key planning parameters listed below form the basis of how the detailed requirements provided in this document should be interpreted. They are:

- Compliance with Uniform System of Accounts

- GAAP (Generally Accepted Accounting Principles)
- GARP (Generally Accepted Regulatory Principles)
- SI Units (colloquially referred to as metric units) pursuant to the *Weights and Measures Act*
- Average of the opening and closing fiscal year balances for items in rate base
- Total Capitalization (debt and equity) equates to Total Rate Base
- At a minimum there must be three years of data. The three years are defined as:
    - Test Year = Prospective Rate Year
    - Bridge Year = Current Year (Where applicable use Board Approved values)
    - Historical Year = Last complete year of actuals (and if applicable the Board Approved for that year)
- Multi-year data showing the most recent Historical Actual, Historical Board Approved, Bridge Year and Test Year data must be presented on the same sheet for the summary/ main schedules
- All calculations of revenue sufficiency/deficiency should be based on proposed methodologies employed in developing the forecast. The resultant impacts of any methodology change from the prior forecasting methodologies must be provided
- Written direct evidence should be included before the data schedules
- The Board's filing requirements have been designed in a manner to isolate the delivery related sufficiency/deficiency separate and apart from the energy related sufficiency/deficiency. In keeping with that, utilities should provide revenue sufficiency or deficiency calculations net of electricity price differentials captured in the RSVA's.
- When filing, the electricity price will be that available from the most recent Board approved RPP, at the time of filing.
- Revenue Deficiency/Sufficiency Calculations should exclude the cost of electricity and respective revenue.
- With respect to the claimed revenue sufficiency/deficiency, the applicant should provide a summary of the drivers of the test year sufficiency/deficiency, along with how much each driver contributes. Complete detailed references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it.
- If all revenue sufficiency/deficiency calculations are based on the proposed methodology and if a summary of the drivers of the sufficiency/deficiency is provided as required above, then the impacts of any change in methodologies should be provided on the overall sufficiency/deficiency and on the individual cost drivers contributing to it
- Applicant must file paper copies and electronic data and stakeholders have the option to choose either or both.
- A complete filing includes all documentation detailed in this document.
- A complete filing includes reconciling all the accounts specified in Appendix 2-

A as reported in the rolled up form in the Functionalization step in the cost allocation model with the financial statements. The definitions of those accounts is contained in the Accounting Procedures Handbook

2.1.2 Confidential Information

The Board relies on full and complete disclosure of all relevant information in order to ensure that its decisions are well-informed, and recognizes that some of that information may be of a confidential nature and should be protected as such. The procedures set out in the Practice Direction on Confidential Filings are to be followed by all participants in a proceeding before the Board, unless otherwise directed by the Board. An applicant is to follow the Practice Direction on Confidential Filings if any of the required information is confidential.

The Practice Direction provides for a process for applying for a confidential ruling, objecting to the application, orders that the Board might make, and objecting to the order.

The onus is on the person requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted in any given case. It is the expectation of the Board that parties will make every effort to limit the scope of their requests for confidentiality to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure, and to prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record. This will provide parties with a fair opportunity to present their cases and permit the Board to provide meaningful and well-documented reasons for its decisions.

2.2 Exhibit 1. Administrative Documents

The administrative documents indicated in this section provide the background and summary to the case as filed. There are three sections 1) Administration, 2) an overview of the filing and 3) the background financial information. The detailed requirements for each section are shown below.

Utilities should treat this as an administrative exhibit and exclude all other information from it, such as Volume & Revenue Forecast, Cost of Capital Summary, Rate Base Evidence and the O&M budget. These topics should be addressed in the relevant exhibits.

2.2.1 Administration

- Index
- Application
- Licence & any restrictions
- Contact information

- List of specific approvals requested
- Draft issues list
- Procedural Orders/motions/correspondence
- Accounting Orders
- List of non-compliance with Uniform System of Accounts and reference to Accounting Orders
- Map of System or provide link to webpage
- List of neighbouring utilities
- Explanation of any Host or Embedded utilities
- Utility Organizational charts,
- Corporate Entities Relationship Chart, including information showing; the organization of the entities with respect to each other, the extent to which the parent company is represented on the utility company board, the reporting relationships between utility management and parent company officials, the services and the nature of the services provided to/by entities and any shared services between the entities.
- Planned changes in corporate or operational structure
- Status of Board Directives from previous Board Decisions and/or Orders
- Company Policies and Regulations with respect to electricity services and schedules of service charges
- Where there are changes in the Policies and Regulations of the Company with respect to electricity Services and Schedules of Service Charges, a list of the proposed and existing charges (from the last approved) should be provided.
- List of Witnesses and their Curriculum Vitae

2.2.2 Overview

- Summary of Application (purpose, need and timing of the application and typical customer impact by customer class)
- Budget Directives (Capital & Operating)
    - o Budget directives and guidelines
    - o Economic assumptions used
- Changes in methodology (accounting, normalization, etc.)
- Schedule of overall revenue sufficiency/deficiency
- Numerical schedules detailing the causes of the deficiency/sufficiency

2.2.3 Finance

- Financial Statements – Most recent financial statements of the applicant
- Pro Forma Statements for Bridge and Test Year.
- Financial Statements for all filed historical years (in the case of where more than one historical year is filed).
- Financial Statements should be provided as soon as they are available. If the statements are not available at the time of filing the utility should provide these as an update.
- Financial Statements – if a reference to location on SEDAR or EDGAR is provided, then provide the URL (Web-page address) and one hard copy of

each referenced document.

- To address the concern with the potentially significant variance between the Annual Reports/Audited Financial Reports and the utility's application, the utility will file a detailed reconciliation of the financial results shown in the Annual Reports/Audited Financial Reports with the regulatory financial results filed in the application.
- Parent and all subsidiaries of the applicant are to be identified (name, nature of business and capitalization of the subsidiary). Filing of annual report (actual) and Management's Discussion and Analysis (MD & A) satisfies the requirement to identify and describe the subsidiaries of the utility and the parent company – unless company management believes that these documents do not provide the necessary information sought by the Board, in which case the utility should identify the subsidiaries.
- Annual Reports or Audited Financial Statements (Historical) & Interim Reports (Bridge) for the Utility.
- Proposed accounting treatment, including the treatment of costs of funds for capital projects that have a project life cycle greater than one year. A list of these projects with appropriate need diligence and project plan, including scope, time and cost are to be included.
- Rating Agency Report.
- Prospectuses, information circulars etc. for planned and recent shares issues.

2.3 Exhibit 2. Rate Base

This exhibit includes information on Rate Base, Capital Budgets, and System Expansion. Items used in the computations or derived must include beginning and closing balances of the rate base, working capital, accumulated depreciation, changes in working capital, accrued deferred earnings, and annual amortization of accrued deferred earnings. The information presented here should cover three areas:

1) List of Gross Assets,
2) Accumulated Depreciation, and
3) Allowance for Working Capital.

For each of these areas there will be some common statements required summarizing the rate base. The schedules for rate base should include Historic Actual, Bridge (actuals to date, balance of year as budgeted), and Test Years. Additional required statements for 1 and 2 include:

<u>Continuity Statements (Year-end and are to include Interest during Construction & All overheads)</u>

- Historical Board Approved to Bridge
- Historical Actual to Bridge
- Bridge to Test Year

<u>Variance Analysis</u>
A written explanation is required for rate base related information when there is a variance greater than materiality. Materiality is 1% of total net fixed assets. This applies to the applicant's specific rate base for the following comparisons:

- Historical Board Approved v/s Historical Actual
- Historical Actual vs. Bridge
- Bridge vs. Test Year

1. Gross Assets – Property Plant and Equipment

(Summary and Continuity statements, including any interest, must be provided)

- Breakdown by function (transmission plant, distribution plant, general plant, other plant) for required statements and analysis
- Detailed breakdown by major plant account for each functionalized plant item for Historical Actual, Bridge and Test Year. For Test year each plant item should be accompanied by a written description.
- Customer Additions and System Expansion with PI values where applicable
- Average of the opening and closing year balances.

<u>Capital Budget - Historic Year, Bridge Year & Test Year</u>

- Capital Budget by project
  - Projects over the materiality threshold of 1% of total net fixed assets should include need, scope, related customer attachments, volumes and capital costs. Provide a detailed breakdown of starting dates and in-service dates.
  - Where a proposed project requires a leave to construct under Section 92 and that project is included in the capital budget in the rates application with the construction commencement in the test year, the evidence for that project must satisfy the requirements set out in section 4.3, section 4.4 and Chapter 5; and for
  - Other Capital Expenditures (Reconcile components to Total Capital Budget).
  - A written explanation of variances should be presented where the variance is greater than or equal to materiality
  - Applicant's capitalization policy and any changes to that policy should be presented as part of the capital budget evidence.

2. Accumulated Depreciation

Summary and Continuity statements must be provided for Historic, Bridge and Test Years by asset account. Continuity statements should be reconcilable to calculated depreciation costs and presented by asset account.

3. Allowance for Working Capital

Historic, Bridge Year & Test Year (except as otherwise noted) on a single schedule

If the utility is applying using the 15% of specific O&M accounts formula approach, the calculation by account must be shown for each of the years required.

If the utility is applying for a working capital based on a detailed analysis, the following is a minimum requirement:

A. Supplies and Materials
- Calculation of average of the opening and closing year balances ($)

B. Prepaid Expenses
- Calculation of average of the opening and closing year balances ($)

C. Miscellaneous Accounts Receivable
- Calculation of average of the opening and closing year balances ($)

D. Working Cash Allowance (Test Year)
- Particulars of calculation

E. Security Deposits
- Calculation of average of the opening and closing year balances ($)

Other Items of Working Capital (itemized individually)
- Calculation of average of the opening and closing year balances ($) if applicable

2.4 Exhibit 3. Operating Revenue

The volume and revenue forecast, any normalization methodology, and other sales activities are provided here. Utilities must include a detailed description of the methodologies and the assumptions used. The information presented should include (estimates must be presented excluding commodity revenues):

1) Throughput Revenue,
2) Other Revenue, and
3) Revenue Sharing. If normalization is employed, then all data must be presented in the normalized form.

1. Throughput Revenue

- Explanation of causes and assumptions for the volume forecast
- Explanation of the normalization methodology and its application
- Historical data related to average use should be normalized if normalization is used, to both the current test year normal and to the normal approved (or last approved) by the Board for the specific year.

- All data used to determine the forecasts should be presented in MS Excel spreadsheet format.
- Schedule of throughput details showing volumes, revenues, unit revenues and customer count by rate for:
    - Historical Actual
    - Historical Board Approved
    - Historical Actual – normalized
    - Bridge Year
    - Bridge – normalized
    - Test Year

  Variance Analysis
    - Historical Board Approved vs. Historical Actual – normalized
    - Historical Actual- normalized vs. Bridge – normalized
    - Bridge – normalized vs. Test Year

- For residential, general service, commercial and industrial customers, normalized (if applicable) average consumption historic actual and forecasted consumption per customer for past 5 years and forecasted average consumption for the Test Year.
- Explanation of net change in general service and industrial customers per rate class from last Board Approved and actual for Historical and Bridge years
- Customer Additions forecast for the test year with explanations of forecast by rate class
- All economic assumptions and their sources used in the preparation of the throughput revenues should be included in this section. (E.g. Housing Outlook & Forecasts, relative energy prices and other variables used in forecasting volumes).

2. Other Revenue

- Details and breakout of Other Revenue and a description of each of the revenue sources should be provided.
- Comparison of Actual revenues to for Historical and Bridge years.
- Detailed calculation of rate of return on non-core delivery activities if they exist.

2.5 Exhibit 4. Operating Costs

The operating cost exhibit must include information that summarizes the total cost of service as proposed including:

1) Operating & Maintenance and Other Costs,
2) PILs or Taxes, (including Income and Large Corporation Tax),
3) Status of Non-RSVA Deferral Accounts and Variance Accounts, and
4) CDM

1. Operating & Maintenance and Other Costs

The required statements for each of the components of this section include trend data for Operating costs (Board Approved v/s Actual) by major item, excluding energy.

A. Operating & Maintenance
(Include Administration & General, Sales Promotion & Customer Accounting)
The written direct evidence is to give further details of the budgets.

Required Statements for O & M:
Historical Board Approved
Historical Actual
Bridge Year
Test Year

The statements should provide:

- Breakdown of each on a work basis,
- Distribution expenses incurred through the purchase of services or products must be documented and justified if they are to be recovered as part of the revenue requirement and the following provided:
    - identity of each company transacting with the applicant,
    - summary of the nature of the activity transacted,
    - annual dollar value, in aggregate, of transactions,
    - description of specific methodology used in determining the price (summary of tendering process/summary of cost approach)
- Provide the following for shared services:
    - type of service (IT, office space, etc.)
    - total annual expense by service,
    - Rationale and of cost allocators used for shared costs, for each type of service (square footage, computers, headcount, etc.)
- Breakdown of total Full Time Employees (FTE); total Part-Time Employees, Total Salaries & Wages and Benefits, and Salaries & Wages and Benefits charged to O&M:
    - By employee type (i.e. management, analyst, non-unionized, and unionized),
    - Total compensation by group and average level per group,
    - Incentive program, and
    - Status of pension funding and all assumptions used in the analysis

(Employee benefit programs, including pensions, and costs charged to O&M should be detailed for the historical, bridge and test years).

Variance Analysis:
Historical Board Approved vs. Bridge Year
Historical Actual vs. Bridge Year
Bridge Year vs. Test Year
A written explanation is required for operating cost related information when there is a variance greater than or equal to of 1% of total distribution expenses before PILs, whichever is larger.

B. Depreciation/Amortization/Depletion

- Depreciation Study – Only if depreciation rates are to change
- Details of provision for Depreciation, Amortization and Depletion by asset group for Test Year and comparative data for Historic and Board Approved Bridge Year, including asset amount and rate of depreciation

C. Ontario Capital Taxes
(Actual costs versus forecast costs should be provided)

- Detailed Breakdown

D. Corporate Cost Allocation

- Detailed description of the assumptions underlying the allocation of these services
- Document the overall methodology and policy

E. Loss Adjustment Factor

- Calculation showing the distribution losses in each of the previous five years.
- Explanation of losses greater than 5%.
- Details of loss studies and recommendations.
- Details of actions currently planned, and actions taken to reduce losses in previous 5 years and their results.

2. Income Tax , Large Corporation Tax and Ontario Capital Taxes

- Detailed PILs calculation (or actual provincial and federal taxes) including derivation of interest and CCA adjustments – Information of taxes should be provided for Historic, Bridge Year and Test Years.
- All reconciling items should have supporting schedules and calculations.

2.6 Exhibit 5. Deferral and Variance Accounts

Status of RSVA and Non-RSVA Related Deferral and Variance Accounts

- List and provide a brief description of all outstanding Deferral and Variance accounts
- Separate itemization of opening balance, adjustments, accruals, interest and closing balance.
- List and brief description of new proposed accounts for the Test Year

- Balance and detailed method of recovery of existing accounts proposed to be cleared as part of the main rates case including bill impacts and rate design implications.

2.7 Exhibit 6. Cost of Capital and Rate of Return

If the applicant is proposing any changes to its Board approved capital structure then the utility should provide a detailed filing supporting that change.

1. Capital Structure – Amounts & Ratios

The elements of the capital structure required are shown below and must be detailed with the required schedules of: 1) Current Board Approved, 2) Historical Year's Actual, and 3) Test Year:

- Long-Term Debt
- Short-Term/Unfunded Debt (to equate total capitalization with rate base)
- Preference Shares
- Common equity

Justification for proposed capital structure is required. Explanation of changes including:

- Non-scheduled retirement of debt or preference shares and buy back of common shares
- Long-Term Debt, preference shares and common shares offering

2. Component Costs

<u>Historic Year, Bridge Year & Test Year</u>

- Calculation of cost of each item from Test Year
- Justification of forecast costs by item including key economic assumptions
- Profit or loss on redemption of debt and or preference shares
- Consensus Forecasts – Utilities must provide the latest interest rate forecast based on a selection of forecasters that are common to the utilities, e.g., the major banks and the Bank of Canada.

3. Calculation of Return on Equity and Debt

The requirements for cost of capital will be developed and brought into effect through the Board initiated Cost of Capital (EB-2006-0088), 2nd Generation Incentive Regulation Mechanism (EB-2006-0089).

2.8 Exhibit 7. Calculation of Revenue Deficiency or Surplus

This exhibit should include the following net of energy costs and revenues:

- Determination of Net Utility Income
- Statement of Rate Base
- Actual utility return on rate base
- Indicated Rate of Return
- Requested Rate of Return

- Deficiency or Sufficiency in Revenue
- Gross Deficiency or Sufficiency in Revenues

2.9 Exhibit 8. Cost Allocation

A completed Board approved cost allocation must be filed whether the utility proposes to use it or not.

1. **Cost Allocation Study**
   - Proposed Method if the Applicant is proposing a method other than the Board Approved method.

A. Functionalization
- Rate base
- Cost
- Revenue offsets

B. Classification
- Rate base
- Cost
- Revenue offsets

C. Allocation
- Rate base
- Cost
- Revenue offsets
- Allocation factors

D. Summary of current methodology, changes, rationale, and resulting impact for A, B and C and an explanation of the factors employed in A, B and C

2.10 Exhibit 9. Rate Design

This section does not apply to transmitters.

The Rate Design Exhibit, in addition to the existing schedules must show the revenue deficiency recovery, a summary of proposed changes to rates, proposed volume and revenue recovery, deviations from the rate handbook and detailed bill impacts.

1. Existing Rate Schedules

2. Proposed Rate Schedules
- Proposed Rate and Revenue Adjustments
- Detailed calculations of revenue per rate class under current rates and proposed rates by customer class.

- Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component, etc.)
- Calculation of differences between revenue and allocated cost under current rates and proposed rates by customer class
- Explanation and application of non-cost factors to rate design
- Revenue/Cost Ratios for Historic Year and Test Year
- Impact of changes on representative samples of end-users, i.e. volume, percentage rate change, revenue.
- Explanation of proposed changes to terms and conditions of service and rationale behind those changes.

Chapter 3 Filing requirements for the 2nd generation incentive regulation mechanism for electricity distributors

Chapter 3 details the filing requirements for the mechanistic incentive rate adjustment, including the cost of capital to be used, for the years 2007 to 2009. This approach will be used for electricity distributors only when there is no requirement to file a complete cost of service rate application.

NOTE: This Chapter is being developed and will be available at a later date.

Chapter 4 Filing requirements for electricity transmission projects under Section 92 of the OEB Act

4.1 Introduction

This document outlines the filing requirements for applicants under section 92 of the Act, which requires leave of the Board for the construction, expansion, or reinforcement of electricity transmission lines greater than 2 kilometres in length.

The filing requirements set out in this document are not intended to limit applicants in terms of what information they may want to present. Nor do these filing requirements limit the discretion of the Board in terms of what information and evidence it may wish to see.

Under section 81 of the Act, any generator or an affiliate of a generator planning to construct transmission facilities must give notice to the Board per guidelines available on the Board's website **www.oeb.gov.on.ca/documents/cases/Maad/guidelines.pdf**. The Board upon examining the relevant facts may choose to formally review the application by holding a hearing, and in that event will advise the applicant within 60 days of receiving the application of its intention to formally review that application.

Construction of new transmission facilities may require amendment of a transmitter license issued by the Board.

Any person who obtained leave of the Board to construct facilities under section 92 or who is exempt under section 95 may apply to the Board for authority to expropriate land for that purpose.

The Board's role is to ensure that these transmission investments are in the public interest. Subsection 96(2) specifies that, for section 92 purposes, "the Board shall only consider the interests of consumers with respect to prices and the reliability and quality of electricity service."

The filing requirements differ depending on the type of applicant and project. Applicants can be rate regulated, such as licensed transmitters that provide transmission services to third parties at Board approved rates, or non-rate regulated, such as an owner of a large industrial plant or a generation facility that do not provide transmission services to third parties. For rate regulated entities whose revenues are derived from ratepayers, there is an onus to justify before the Board all expenditures on transmission facilities.

Most of the projects proposed by non-rate regulated applicants are designed to connect sites or plants to the electric power system. The financial risk of constructing new transmission facilities lies with the owners and shareholders of the company. These companies do not need to justify their expenditures on transmission facilities. It should be noted that in certain exceptional circumstances these owners and shareholders may be required by the Board to share some or all of the costs associated with the Network Reinforcement as set out in Section 6.3 of the Transmission System Code.

For a rate regulated transmitter, only the filing requirements set out in section 4.3 in this Chapter are needed where a proposed project requires a leave to construct and that project has been included in a capital budget that has been approved in a rates process and the project is approved for construction commencement in the test year.

For a rate regulated transmitter where a proposed project requires a leave to construct and that project had not been included in a capital budget that has been approved in a rates process, the filing requirements are the filing requirements set out in section 4.3, section 4.4, and Chapter 5.

Rate regulated transmitters and distributors applying for connection projects must include additional requirements as set out in the Transmission System Code (TSC) in the submission to the Board.

Section 92 applies for distributors' projects involving transformation connection projects (e.g. a transformer station transforming from above 50 kV to below 50 kV), if the transmission line tap is more than 2 km. in length.

4.1.1 Legislation

Section 92 of the Act requires leave of the Board for the construction, expansion, or reinforcement of an electricity transmission line or an electricity distribution line, as well as for the making of a connection to the power system. Under Ontario Regulation 161/99 however, many projects captured under s. 92 of the Act are exempt from the need for leave to construct. This includes all distribution projects, most connections and projects involving electricity transmission lines that are 2 kilometres or less in length.

Section 95 of the Act allows an applicant to seek an exemption from the requirements of s. 92 of the Act. An applicant must submit such a request accompanied by the special circumstances that warrant an exemption from the requirement to obtain leave to construct under s. 92 of the Act. A project summary report should be submitted for review, consistent with the requirements described in this document. The level of detail in the submission should reflect the issues or concerns encountered during the evaluation phase of the project.

Information on land requirements must be included as part of the leave to construct application. Section 97 of the Act states, "leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board."

4.1.2 Regulatory Framework

Board review of transmission investment can arise in three regulatory settings:

- Review of the Integrated Power System Plan (IPSP) to be submitted by the Ontario Power Authority;
- Review of the capital budget of rate regulated transmitters in transmission rates cases; and
- Review of applications for leave to construct transmission lines.

The Board's authority to review Integrated Power System Plans is established in subsections 25.30 (4), (5), and (6) of the *Electricity Act, 1998*. The first of these subsections states, "The Board shall review each integrated power system plan submitted by the OPA to ensure it complies with any directions issued by the Minister and is economically prudent and cost effective."

The Board's authority to review transmitter's capital budgets and set rates is established in subsection 78 (1) of the Act which states "No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract."

In leave to construct applications, the Board considers the interests of consumers with respect to prices and the reliability and quality of electricity service. Some of these public interest considerations could be determined during the Board's review of the IPSP and/or a rate hearing. In either case, the intention is not to require the applicant to re-establish these as part of the leave to construct proceeding.

A transmission project may be subject to any or all three of these regulatory settings. Avoiding duplication of regulatory review is therefore critical. The conclusions of the Board specific to a project that are made in one regulatory setting will not be re-evaluated in another setting. For example, the need for a project may be established in the IPSP review. The reasonableness of the costs for that project may be reviewed in the IPSP or the transmitter's rate case. Therefore, in this case the need and rate impact of that project would not be matters addressed in a leave to construct proceeding. It would be limited to a review of issues not addressed in the other forums such as the System Impact Assessment (SIA) carried out by the Independent Electricity System Operator (IESO) and the Customer Impact Assessment (CIA) carried out by the relevant licensed transmitter as specified by the Transmission System Code (TSC).

For a project that was granted leave under section 92 of the Act, and if subsequently or concurrently other approvals such as the Environmental Assessment (EA) approval materially alter or affect the specific routing of a transmission line, the original application and the Board order stemming from it would no longer be valid.

4.2 Applicant and Project Types

Filing requirements differ depending on the type of applicant and project. Applicants can be rate regulated or non-rate regulated, depending on whether they propose to provide transmission service to third parties at Board approved rates. For rate regulated entities whose revenues are derived from ratepayers, there is an onus to justify before the Board all expenditures on transmission facilities.

4.2.1 Rate Regulated Applicants

For a rate regulated transmitter where a proposed project requires a leave to construct and that project has been included in an IPSP, only the filing requirements set out in section 4.3 in this Chapter are needed.

For a rate regulated transmitter, only the filing requirements set out in section 4.3 in this Chapter are needed where a proposed project requires a leave to construct and that project has been included in a capital budget that has been approved in a rates process and the project is approved for construction commencement in the test year.

The filing requirements set out in section 4.3, section 4.4 and Chapter 5 shall apply where that project had not been included in a Board approved IPSP or had not been included in a list of approved capital projects with expected construction commencement during the test year.

Rate regulated distributors applying for connection projects such as a transformation connection should follow the common filing requirements set out in section 4.3 in this Chapter.

Transmitters and distributors applying for connection projects must also include additional requirements as set out in the TSC in their submissions to the Board.

4.2.2 Non Rate Regulated Applicants

Most of the projects proposed by non rate regulated applicants are designed to connect sites or plants to the electric power system. The financial risk of constructing new transmission facilities lies with the owners and shareholders of the company. The filing requirements for non-regulated entities reflect this risk structure.

4.3 Filing Requirements for Projects under Section 92

The analysis of public interest implications may vary depending on the Applicant (rate regulated or non-rate regulated) and type of transmission project being reviewed. The following filing requirements apply to projects, which are considered in a leave to construct proceeding.

4.3.1 Project Summary

The evidence supporting the application must contain a project summary. This should provide:

- the name of the applicant and any authorized representative of the applicant
- a concise description of the location of the project
- description of all project components, activities, and related undertakings
- the purpose or need for the project
- the rationale for selecting the proposed project, and how the project is in the public interest
- the project schedule

4.3.2 Project Location

The application must include a detailed description of location of the project and its components, including:

- maps (1:50,000 or larger) showing: the route, facility sites and any proposed ancillary facilities;
- the location of project components and related undertakings;
- line drawings of the proposed facility, showing supply connection(s) to the proposed facility and delivery facilities from the proposed facility to any adjacent transmission and/or distribution system(s)

4.3.3 Need for the Project (for Rate Regulated Transmitters)

The applicant must provide a description of the need for the project. Any projects forming part of an approved IPSP or rate order should provide a detailed reference to those approvals and the reasons given for their inclusion in those proceedings. For projects without IPSP or rate approval, the applicant must describe the purpose of the facilities and public interest benefits expected from their construction as outlined in Chapter 5.

4.3.4 Design Specifications and Operational Details

The application must provide a description of the physical design, operational details, and lifecycle activities of the proposed project, identifying project design features and procedures that will ensure the safe and reliable operation of the proposed facilities. These design specifications should demonstrate compliance with the technical requirements as specified in the TSC.

4.3.5 Construction and In-service Schedule

The applicant must provide the Board with time estimates for construction and service dates, including:

- the critical path and time frame for the completion of construction and operational start-up of the proposed facilities relative to the introduction of the new or additional market demands on the transmission system; and
- the estimated schedule (time of year and duration) for each of the major construction activities and the implications of critical constraints such as:
  - delay in start of construction due to failure to obtain timely approvals;
  - prolonged adverse weather conditions;
  - availability of qualified contractors and/or skilled trades persons;
  - construction windows due to environmental constraints; and
  - the projected and contractual in-service date for the facilities.

4.3.6 Land Matters

The application must include accurate documentation of land requirements, land rights, service of notices, and the land acquisition process, that demonstrates compliance with legislative requirements and respects the rights of affected parties.

A description of the land area required including:

- the width(s) of any right-of-way required on new and/or existing easements;
- the location and ownership of land with existing easements and of any new easements or land use rights that will be required; and
- the need and amount of additional temporary working rights required at designated locations such as crossings of rivers, roads, railways, drains and other facilities.

A description of the land rights required must be provided:

- the type of land rights proposed to be acquired for the project and related facilities (e.g. permanent easement, fee simple);
- the nature and relative proportions of land ownership along the proposed route (i.e., freehold, Crown or public lands); and
- where no new land rights are required, provide a description of the existing land rights that allow for the project.

A description of the land acquisition process including:

- identification of the properties and the property owners and/or tenants

affected by the proposed construction (landowners line list);
- the extent of notification to landowners regarding the routing of the new facility, the environmental assessment and the facility application;
- the applicant's plan for acquiring new easements or for amending existing easements; and the progress achieved to date with affected landowners, any concerns, or objections registered by affected landowners and municipalities with respect to the proposed construction, and the resolution of these concerns.

A copy of each of the following forms must be submitted where applicable and where an up-to-date copy is not already on file with the Board:
- the option for easement form;
- the working rights agreement form;
- the easement agreement form;
- the damage release form; and
- a copy of any correspondence with affected landowners outlining changes in company policy with respect to land acquisitions.

4.3.7 Community and Stakeholder Consultation

The Board expects applicants will consider consultation for all projects. Applicants are responsible for justifying the extent of consultation carried out for each application. The following information should be provided within the application:
- principles and goals of the consultation program;
- design details of the consultation program; and
- the results of the consultation carried out, including how public input influenced the design, construction, or operation of the project; or
- an explanation if no consultation was pursued.

4.3.8 System Impact Assessment

The IESO Connection Assessment and Approval process identifies the detailed procedures to be followed by applicants who wish to connect or modify a connection to the IESO-administered grid. The IESO evaluates the design of the project and its impact on integrated power system reliability, and identifies any transmission facility enhancements required. IESO requirements must be fulfilled in addition to those listed here.

4.3.9 Customer Impact Assessment

The Applicant, including a rate regulated transmitter if it is the Applicant, is required to include in its evidence a Customer Impact Assessment (CIA) report, as required by the TSC.

The CIA report is to be completed by the rate regulated transmitter to which the Applicant's transmission facilities are connected. A transmitter shall carry out a CIA for any proposed new or modified connection where:

- the connection is one for which the IESO's connection assessment and approval process requires a system impact assessment; or
- the transmitter determines that the connection may have an impact on existing customers.

A transmitter may decide not to carry out a CIA for any proposed new connection or modification that is not subject to a system impact assessment. In such a case, the transmitter would notify existing customers in the vicinity, advising them of the proposed new connection or modification and of the transmitter's decision not to carry out a CIA on the basis that no customer impact is expected.

A transmitter would provide each affected customer with a new available fault current level at its delivery point(s). This in order to allow each customer to take, at its own expense, action to upgrade its facilities as may be required to accommodate the new available fault current level up to the maximum allowable fault levels set out in Appendix 2 of the TSC.

4.3.10 Connection Project Impacts on Transmission System

Certain connection projects may require network reinforcement in order to proceed. A description of the requirements is provided in Appendix 4-A to this Chapter. Where an applicant attributes to a proposed project market efficiency benefits such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project.

4.3.11 Other Matters

The application must provide description of any other applicable codes, standards, and regulations. It must also provide engineering details with respect to any special design features, which may influence the construction and in-service schedule and to demonstrate that the proposed transmission facilities will be safe and reliable.

4.4 Filing Requirements for Rate Regulated Transmitters [First Time Board Review of Projects]

Rate regulated transmitters applying for projects that had not been included in a Board approved in a list of capital projects, with expected construction commencement during the test year, in the most recent rate hearing that has been approved by the Board must provide evidence as set out in Chapter 5 of this document.

Chapter 5 Prior to the approval of an Integrated Power System Plan: Filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the OEB Act

5.1 Introduction

Chapter 5 outlines the filing requirements for applications by rate regulated transmitters for:

- approval of the capital budget for electricity transmission projects in transmission rate cases in accordance with section 78 of the Act.
- leave of the Board for the construction, expansion or reinforcement of electricity transmission lines under section 92 of the Act. It should be noted that the filing requirements in this chapter are required in addition to the filing requirements set out in section 4.3 in Chapter 4.

Rate regulated distributors applying for connection projects such as a transformation connection should follow the filing requirements set out in this Chapter. Additional requirements as set out in the TSC must also be included in the submission to the Board.

5.1.1 Legislation

The Board's authority to review transmitter's capital budgets and set rates is established in subsection 78(1) of the Act, which states, "No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract."

Section 92 of the Act requires leave of the Board for the construction, expansion, or reinforcement of an electricity transmission line or an electricity distribution line, as well as for the making of a connection to the power system. Under Ontario Regulation 161/99, however, many projects captured under section 92 of the Act are exempt from the need for leave to construct. This includes all distribution projects, most connections and projects involving electricity transmission lines that are 2 kilometres or less in length.

5.1.2 Regulatory Framework

A transmission project may be subject to a leave to construct application or a capital budget review in rate hearings. Avoiding duplication of regulatory review is therefore critical. The conclusions of the Board specific to a project that are made in one regulatory setting will not be re-evaluated in another setting. The reasonableness of incurred costs for a project may be reviewed in the transmitter's rate case. In this case the need and rate impact of that project would not be addressed in the leave to construct proceeding. The review would be limited to issues not addressed in the other forums such as the System Impact Assessment (SIA) carried out by the Independent Electricity System Operator (IESO) and the Customer Impact Assessment (CIA) carried out by the relevant licensed transmitter as specified by the Transmission System Code.

In leave to construct applications, the Board considers the interests of consumers with respect to prices and the reliability and quality of electricity service. Some of these public interest considerations could be determined during the Board's review in a rate hearing. The intention is not to require the applicant to re-establish these as part of the leave to construct proceeding.

5.2 Project Categorization

Project categorization consists of two stages.

The first categorization stage is the classification of a project into one of three project classes:

- Development; or
- Connection; or
- Sustainment.

The second categorization stage is identifying the project need as:

- Non-discretionary – a "must do" project, the need for which is determined beyond the control of the Applicant ("Non-discretionary"), or
- Discretionary – the need is determined at the discretion of the Applicant ("Discretionary").

The following table captures these two dimensions of the project categorization and the subsequent sections of this Chapter provide further clarification.

		PROJECT NEED	
		Non-discretionary	Discretionary
PROJECT CLASS	Development		
	Connection		
	Sustainment		

5.2.1 Project Classification (Development, Connection, Sustainment)

The first stage of project categorization is the classification of a project as development, connection, or sustainment.

- Development projects are those for providing:
  - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
  - enhancing system efficiency such as minimizing congestion on the transmission system and reducing system losses.
- Connection projects are those for providing connection of a load or generation customer or group of customers to the transmission system.
- Sustainment projects are those for maintaining the performance of the transmission network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, the applicant should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

An investment in the Network may be required in any of these three project classifications. Network facilities are comprised of network stations and the transmission lines joining them.

5.2.2 Project Need

The second stage of project categorization is to distinguish whether the project need is determined beyond the control of the Applicant ("Non-discretionary") or determined at the discretion of the Applicant ("Discretionary").

Non-discretionary projects may be triggered or determined by such things as:

- Mandatory requirement to satisfy obligations specified by Regulatory Organizations including NPCC/NERC (the designated ERO in the future) or by the Independent Electricity Market Operator (IESO);
- A need to accommodate new load (of a distributor or large user) or new generation (connection);
- A need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- Projects identified in an approved IPSP;
- Projects that are required to achieve Government objectives that are prescribed in governmental directives or regulations;
- A need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Discretionary projects are proposed by the Applicant to enhance the transmission system performance benefiting its users. Projects in this category may include:

- Projects to reduce transmission system losses;
- Projects to reduce congestion;
- Projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- Projects to enhance reliability beyond a minimum standard;
- Projects which add flexibility to the operation and maintenance of the transmission system.

5.3 Project Justification

Project justification delineates the responsibilities and necessary evidentiary components required for the project review. The responsibility for the provision of all evidence for the entire case rests with the Applicant.

5.3.1 Evidence in Support of Need

The Applicant's evidence in support of the need for the project is required and can be supported by evidence of the IESO and/or the Ontario Power Authority:

- where a proposed project is best compared to other viable transmission alternatives, including "doing nothing"; and
- where the Applicant lists benefits of avoiding non-transmission alternatives such as a peaking generation facility or a "must run" generation requirement, it is helpful for the Applicant to include corroborative evidence from the IESO or the OPA regarding the Applicant's quantitative evaluation of such a benefit. In any event, this evidence is required to support the need for the project.

It is therefore expected that the applicant will provide a list identifying the key driving factors of the evidence justifying the project need, and the party (e.g. the applicant, the IESO, or the OPA) which has prepared the evidence to justify a given key driving factor.

In some cases, the need for a discretionary or non-discretionary project is driven by factors external to the Applicant, such as the need to satisfy an IESO requirement or to serve an incremental customer load. The factors driving the project must be identified, but the burden remains on the Applicant to support the claim of need. If the Applicant identifies a customer or agency as the driver behind a project, it is the Applicant's responsibility to include evidence from that customer or agency as part of the evidence on the application. The Board expects the Applicant to work with that external party in the development of the required evidence. In many cases the external party will be the IESO and/or the OPA, although the additional evidentiary requirement would apply to any external party on whom the Applicant has relied for the justification of the need for the project. The evidence will likely consist of written material prepared by the customer or agency specifically addressing the proposed project, and the customer or agency must be prepared to provide witnesses to support the filed evidence if an oral hearing is held. It is not sufficient for the applicant to state that the customer or agency has established the need for the project; the Board must be able to test that assertion.

5.3.2 Options and Cost Benefit Analyses

In addition to the evidence regarding the need for the project, the Applicant must address how it proposes to accomplish the project including the identification of relevant options. This section outlines the required evidence for that aspect of the application. The basic form for such evidence should be cost benefit analyses of various options. The Board expects that Applicants will present a preferred option (i.e., the proposed project) and alternative options. It should be recognized, however, that the Board will either approve or not approve the proposed project (i.e. the preferred option). It will not choose a solution from among the alternative options. The Applicant should present the smallest number of alternatives consistent with conveying to the Board the major solution concepts available to meet the same objectives that the preferred option meets. The applicant is expected to also compare the alternatives versus the preferred option along various risk factors including, but not limited to, financial risk to the applicant, inherent technical risks, estimation accuracy risks, and any other critical risk that may impact the business case supporting the proposed project.

For connection projects, in addition to the cost benefit analysis, the Applicant must supply specific information on the nature and magnitude of the network impacts.

In the case of a non-discretionary project, the preferred option should establish that it is a better project than the alternatives. The Applicant need not include “doing nothing” as an alternative since this alternative would not meet the need. One way for an Applicant to demonstrate that that a preferred option is the best option is to show that it has the highest net present value as compared to the other viable alternatives. However, this net present value need not be shown to be greater than zero. In the case of an internally set project, “doing nothing” would count as a viable option.

If the proposed project or alternatives are expected to have significant qualitative benefits that cannot reasonably be quantified, evidence about these qualitative benefits should be provided. These benefits may be taken into account in ranking the projects. Incorporating qualitative criteria may result in a different ranking of projects compared to the ranking based on quantitative benefits and costs alone.

5.3.3 Project Summary

The evidence supporting the application must contain a project summary. This should provide:

- a concise description of the location of the project;

- description of all project components, activities, and related undertakings;
- the purpose or need for the project;
- the rationale for selecting the proposed project, and how the project is in the public interest; and
- the project schedule.

5.3.4 Project Cost

Project costs should provide details covering:

- labour - including a breakdown by facility installations;
- materials - including a breakdown of all facility costs;
- cost of similar projects constructed by the applicant or by other entities for baseline cost comparisons covering;
    - in-service year of the comparator project, and
    - similarities and differences in terms of voltage level, type of towers, type of terrain, etc.
- acquisition of land use rights, and land acquisition including permanent and working easements, survey and appraisals, legal fees, crop and damage compensation;
- direct and indirect overheads broken down by facility installation; and
- allowance for funds used during construction (AFUDC).

5.3.5 Transmission Rate Impact Assessment

The Board requires information relating to the rate impacts anticipated from transmission investments. Information should cover the short-term impacts as well as long-term impacts of the proposed project.

5.3.6 Establishment of Deferral Accounts

The Board would consider applications by licensed transmitters requesting that the Board include with its grant for leave to construct, the establishment of a deferral account (under the Uniform System of Accounts) to track the project construction costs and that such accounts would be reviewed for prudence and inclusion in rate base in a future rate proceeding.

Chapter 6 Filing requirements for electricity distribution companies' applications for supplemental 2007 conservation and demand management funding, recovery of lost revenue and shared savings

6.1 Introduction

In 2005 distribution rates, the Board approved $163 million in Conservation and Demand Management ("CDM") funding for electricity distribution companies which was related to the third tranche of their Market Adjusted Revenue Requirement. This funding was assigned for CDM expenditures covering a period ending September 30, 2007.

The Board also determined that a Lost Revenue Adjustment Mechanism ("LRAM") and a Shared Savings Mechanism ("SSM"), associated with these programs, were appropriate. It was decided that both of these mechanisms should be recovered on a retrospective basis.

The Board also provided guidance through the 2006 Electricity Distribution Rate Handbook as to the process distributors can take to gain additional funding (beyond third tranche) in the 2006 rate year. In September 2005, the Board also released its Total Resource Cost ("TRC") Guide to assist distributors in performing cost benefit analysis.

On July 13, 2006, the Minister of Energy issued a directive for the Ontario Power Authority ("OPA") addressing CDM commitments for the OPA. The OPA was directed to organize the delivery and funding of CDM programs through the electricity distributors in the earliest practical time frame. The directive indicated that funding of $400 million would be available over three consecutive years. Due to the considerable effort required by the OPA to meet its responsibilities under the Directive, the OPA is targeting October 2007 for implementation of the CDM funding.

While the third tranche funding continues to September 30, 2007, the incremental funds for the 2006 rate year do not. That funding ends April 30, 2007. This creates a funding gap for incremental CDM between the end of the funding for CDM through rates and the beginning of the funding through OPA contracts. As such, the Board is now providing guidance as to how distributors can apply for incremental CDM funding to cover the period May 1, 2007 to September 30, 2007.

This Chapter will assist distributors in their applications for additional CDM funding until the OPA funds are available and to facilitate the filing of applications for LRAM and SSM for CDM programs.

6.2 Incremental 2007 CDM Funding

The filing for incremental CDM funding for the period May 1, 2007 to September 30, 2007, before the OPA funding and programs are available, closely follow the filing guidelines contained in the 2006 EDR Handbook, Schedule 3-4.

If an applicant is seeking approval of CDM spending in 2007 that is incremental to funding previously approved by the Board, the following information must be provided.

1. Characteristics of the applicant's distribution system, including:
   - Peak system load by season;
   - Average seasonal daily and weekly system load shapes;
   - Total energy purchases;
   - Sales by rate class; and
   - Number of customers by rate class.

2. For each initiative where costs are claimed in addition to costs already covered in approved 2006 rates, the following information must be provided:
   - General description of the programs;
   - Customer class(es) targeted;
   - Projected incremental demand (kW) or energy (kWh) savings;
   - Projected budget, listing:
     - capital expenditures in 2007;
     - operating expenditures for 2007, separated into direct and indirect expenditures; and
     - for each direct operating expenditure, an allocation of the expenditure by targeted customer classes;
   - Measure, programs and portfolio cost effectiveness results;
   - The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;
   - The cost / benefit analysis, calculating the net present value of the initiative using the TRC test. For the purpose of calculating the net present value, a distributor must use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; and
   - A discussion of how the proposed initiative is consistent with proposed programs by the OPA.

3. The distributor should also provide:
   - The total amount of CDM spending to be recovered in rates and the allocation of those costs to the customer class(es) that will benefit from the conservation program applied for;

- A forecast of the number of customers in each class and a forecast of kWs or kWhs to be used as a charge determinant to determine the rate rider for each class to benefit from the CDM program; and
- A comparison of the proposed rates with and without the CDM rider for the rate year in question.

4. A distributor will be required to report annually on the results of each initiative for which spending is approved as well as the revenues generated by the CDM rider.

6.3 Lost Revenue Adjustment and Shared Savings Mechanisms

When applying for LRAM or SSM, a distributor should ensure that sufficient time has passed to ensure that the actual information needed to support the application is available.

As prescribed in the Board's RP-2004-0203 decision of December 2004, and outlined in the subsequent 2006 EDR Report of the Board, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings using the Board-approved variable distribution charge appropriate to the class. The resulting amount will be entered into a deferral account and may be claimed in a subsequent rate year as compensation for lost revenue.

Lost revenue will be calculated using the variable distribution rate (kW or kWh) for each affected class and would not include any Regulatory Asset Recovery rate riders, as these funds have their own independent true-up process in place. In addition, lost revenues are only accruable until new rates (new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

Information required when filing the application for LRAM should include:

- kW or kWh impacts (both gross and net of free riders) of each program and for each class;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the TRC Guide, the distributor must comply with the requirements set out in the TRC Guide respecting custom projects; and
- Duration of the program in years or months.

All information filed for the LRAM proposal should correspond to program information used in the calculation of the cost/benefit analysis.

For the purpose of making an SSM claim, all of the information requirements listed above are required. SSM applies only to customer focused initiatives that reduce the demand for electricity and/or reduce the amount of energy used and only where the costs of the initiatives are expensed.

The distributor must calculate the net benefits of a program using the TRC test. Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio, through a rate rider.

These instructions respecting SSM replace those that were posted to the Board's website on April 28, 2005.

6.4 Integration of the 2007 CDM Funding, LRAM and SSM Filings with the May 1, 2007 Distribution Rate Adjustments

6.4.1 Distributors with Approved 2006 CDM Funding

A number of distributors have 2006 distribution rates approved which include the recovery of additional CDM funding over and above the 3rd tranche funding approved in 2005. When distribution rates are adjusted for May 1, 2007, non-capital funding will be removed from rates before Cost of Capital changes, 2nd Generation Incentive Regulation changes and any 2007 CDM funding, LRAM or SSM rate changes are implemented. Approved 2006 CDM capital expenditures will remain in rate base until the distributor's next rate base hearing is held.

Rate riders for recovery of 2007 CDM expenditures and for LRAM and SSM recoveries will be developed using the distributor's most recently approved load forecast. The rate riders will be designed to recover approved costs from May 1, 2007 until April 30, 2008 even though the spending is only to recover costs incurred from May 1 to September 30, 2007. At the time of the next distribution rate change on May 1, 2008, the riders will be removed from base distribution rates, before 2008 Cost of Capital and 2008 2nd Generation Incentive Regulation changes are applied.

Appendix 2-A

List of Accounts

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1805-1	**Land Station >50 kV**
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1806	**Land Rights**
1806-1	**Land Rights Station >50 kV**
1806-2	**Land Rights Station <50 kV**
1808	**Buildings and Fixtures**
1808-1	**Buildings and Fixtures > 50 kV**
1808-2	**Buildings and Fixtures < 50 KV**
1810	**Leasehold Improvements**
1810-1	**Leasehold Improvements >50 kV**
1810-2	**Leasehold Improvements <50 kV**
1815	**Transformer Station Equipment - Normally Primary above 50 kV**
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1825	**Storage Battery Equipment**
1825-1	**Storage Battery Equipment > 50 kV**
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1830	**Poles, Towers and Fixtures**
1830-3	**Poles, Towers and Fixtures - Subtransmission Bulk Delivery**
1830-4	**Poles, Towers and Fixtures – Primary**
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1835	**Overhead Conductors and Devices**
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1835-4	**Overhead Conductors and Devices – Primary**
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1840	**Underground Conduit**
1840-3	**Underground Conduit - Bulk Delivery**
1840-4	**Underground Conduit – Primary**
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1845	**Underground Conductors and Devices**
1845-3	**Underground Conductors and Devices - Bulk Delivery**
1845-4	**Underground Conductors and Devices - Primary**
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1850	**Line Transformers**
1855	**Services**
1860	**Meters**
1905	**Land**
1906	**Land Rights**
1908	**Buildings and Fixtures**
1910	**Leasehold Improvements**

1915	Office Furniture and Equipment
1920	Computer Equipment – Hardware
1925	Computer Software
1930	Transportation Equipment
1935	Stores Equipment
1940	Tools, Shop and Garage Equipment
1945	Measurement and Testing Equipment
1950	Power Operated Equipment
1955	Communication Equipment
1960	Miscellaneous Equipment
1970	Load Management Controls - Customer Premises
1975	Load Management Controls - Utility Premises
1980	System Supervisory Equipment
1990	Other Tangible Property
1995	Contributions and Grants – Credit
2005	Property Under Capital Leases
2010	Electric Plant Purchased or Sold
2050	Completed Construction Not Classified--Electric
2105	Accumulated Amortization of Electric Utility Plant - Property, Plant, & Equipment
2120	Accumulated Amortization of Electric Utility Plant - Intangibles
3046	Balance Transferred From Income
4080	Distribution Services Revenue
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4090	Electric Services Incidental to Energy Sales
4205	Interdepartmental Rents
4210	Rent from Electric Property
4215	Other Utility Operating Income
4220	Other Electric Revenues
4225	Late Payment Charges
4235	Miscellaneous Service Revenues
4240	Provision for Rate Refunds
4245	Government Assistance Directly Credited to Income
4305	Regulatory Debits
4310	Regulatory Credits
4315	Revenues from Electric Plant Leased to Others
4320	Expenses of Electric Plant Leased to Others
4325	Revenues from Merchandise, Jobbing, Etc.
4330	Costs and Expenses of Merchandising, Jobbing, Etc.
4335	Profits and Losses from Financial Instrument Hedges
4340	Profits and Losses from Financial Instrument Investments
4345	Gains from Disposition of Future Use Utility Plant
4350	Losses from Disposition of Future Use Utility Plant
4355	Gain on Disposition of Utility and Other Property
4360	Loss on Disposition of Utility and Other Property
4365	Gains from Disposition of Allowances for Emission
4370	Losses from Disposition of Allowances for Emission
4390	Miscellaneous Non-Operating Income
4395	Rate-Payer Benefit Including Interest

4398	Foreign Exchange Gains and Losses, Including Amortization
4405	Interest and Dividend Income
4415	Equity in Earnings of Subsidiary Companies
5005	Operation Supervision and Engineering
5010	Load Dispatching
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders - Operation
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5050	Underground Subtransmission Feeders - Operation
5055	Underground Distribution Transformers - Operation
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Materials and Expenses
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5096	Other Rent
5105	Maintenance Supervision and Engineering
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5175	Maintenance of Meters
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses
5405	Supervision
5410	Community Relations – Sundry

5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense
5515	Advertising Expense
5520	Miscellaneous Sales Expense
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses
5615	General Administrative Salaries and Expenses
5620	Office Supplies and Expenses
5625	Administrative Expense Transferred Credit
5630	Outside Services Employed
5635	Property Insurance
5640	Injuries and Damages
5645	Employee Pensions and Benefits
5650	Franchise Requirements
5655	Regulatory Expenses
5660	General Advertising Expenses
5665	Miscellaneous General Expenses
5670	Rent
5675	Maintenance of General Plant
5680	Electrical Safety Authority Fees
5685	Independent Market Operator Fees and Penalties
5705	Amortization Expense - Property, Plant, and Equipment
5710	Amortization of Limited Term Electric Plant
5715	Amortization of Intangibles and Other Electric Plant
5720	Amortization of Electric Plant Acquisition Adjustments
5730	Amortization of Unrecovered Plant and Regulatory Study Costs
5735	Amortization of Deferred Development Costs
5740	Amortization of Deferred Charges
6105	Taxes Other Than Income Taxes
6110	Income Taxes
6205	Donations
6210	Life Insurance
6215	Penalties
6225	Other Deductions

Appendix 4-A

Connection Projects Requiring Network Reinforcement

Reviewing connection projects require submission of evidence to cover various aspects including:

- Transmission System Impact and Network Reinforcement
- Cost Responsibility for Network Reinforcement
- Implementation of Required Network Upgrades

Transmission System Impact and Network Reinforcement

The applicant must supply information on the nature and magnitude of any impact of the proposed connection facility on the transmission system. Normally the IESO addresses and provide high level assessment of such impacts in the System Impact Assessment report performed by the IESO as set out in the IESO's Connection Assessment and Approval process.

This information will not be determinative of the decision on leave to construct in these cases as the cost responsibility of line connection investments are addressed fully in the Transmission System Code (TSC) and the applicant is responsible for demonstrating compliance with the TSC.

However, the Board may wish to determine whether a transmitter(s) needs to apply for a leave to construct to make the required network upgrades triggered by the proposed connection project. If a leave to construct is necessary, the Board may wish to invite the transmitter(s) to make the needed applications at the same time, or immediately following, the application of the connecting customer.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified (e.g., changes in generation dispatch and transmission line losses).

Cost Responsibility for Network Reinforcement

Section 6.3.5 of the TSC states that "A transmitter shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's network facilities that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction."

Transmitters and other interested parties may apply to the Board for direction on the existence of "exceptional circumstances" requiring the connecting customer to make a capital contribution for network investments triggered by their proposed line connection. The onus is on the transmitter and other interested parties to establish to the Board's satisfaction that "exceptional circumstances" exist.

Implementation of Required Network Upgrades

When the proposed investment requires network upgrades to comply with the TSC and other industry standards and codes, the nature and magnitude of the necessary upgrades must be identified.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified (e.g., changes in generation dispatch and transmission line losses).

A key objective of the OEB in these contexts is early identification of the magnitude of any upstream network impacts resulting from a connection investment. This early identification will enable the OEB to determine if relevant rate regulated transmitters should be invited to pursue leave to construct applications. A related objective is to enable any person to make application to the Board under section 6.3.5 of the TSC for a finding that exceptional circumstances apply, and that the connection proponent should therefore bear some portion of the cost responsibility for the resulting network upgrades that are required.

Appendix 5-A

Connection Projects Requiring Network Reinforcement

Reviewing connection projects require submission of evidence to cover various aspects including:

- Transmission System Impact and Network Reinforcement
- Cost Responsibility for Network Reinforcement
- Implementation of Required Network Upgrades

<u>Transmission System Impact and Network Reinforcement</u>

The applicant must supply information on the nature and magnitude of any impact of the proposed connection facility on the transmission system. Normally the IESO addresses and provide high level assessment of such impacts in the System Impact Assessment report performed by the IESO as set out in the IESO's Connection Assessment and Approval process.

This information will not be determinative of the decision on leave to construct in these cases as the cost responsibility of line connection investments are addressed fully in the Transmission System Code (TSC) and the applicant is responsible for demonstrating compliance with the TSC.

However, the Board may wish to determine whether a transmitter(s) needs to apply for a leave to construct to make the required network upgrades triggered by the proposed connection project. If a leave to construct is necessary, the Board may wish to invite the transmitter(s) to make the needed applications at the same time, or immediately following, the application of the connecting customer.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified (e.g., changes in generation dispatch and transmission line losses).

<u>Cost Responsibility for Network Reinforcement</u>

Section 6.3.5 of the TSC states that "A transmitter shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's network facilities that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction."

Transmitters and other interested parties may apply to the Board for direction on the existence of "exceptional circumstances" requiring the connecting customer to make a capital contribution for network investments triggered by their proposed line connection. The onus is on the transmitter and other interested parties to establish to the Board's satisfaction that "exceptional circumstances" exist.

Implementation of Required Network Upgrades

When the proposed investment requires network upgrades to comply with the TSC and other industry standards and codes, the nature and magnitude of the necessary upgrades must be identified.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified (e.g., changes in generation dispatch and transmission line losses).

A key objective of the OEB in these contexts is early identification of the magnitude of any upstream network impacts resulting from a connection investment. This early identification will enable the OEB to determine if relevant licensed transmitters should be invited to pursue leave to construct applications. A related objective is to enable any person to make application to the Board under section 6.3.5 of the TSC for a finding that exceptional circumstances apply, and that the connection proponent should therefore bear some portion of the cost responsibility for the resulting network upgrades that are required.

Appendix 5-B

Summary of Transmission Investment Classifications and Filing Requirements of Rate Regulated Transmitters

<table>
<tr><th>Project Class</th><th>Information Requirements</th><th>Alternatives</th></tr>
<tr><td>Sustainment</td><td>Reasonableness of costs and compliance with any relevant standards, codes, norms, for good utility practice</td><td>Alternatives not relevant unless scope of project significantly exceeds previous requirements</td></tr>
<tr><td>Connection</td><td>1. Demonstrate compliance with relevant standards, codes, norms for good utility practice (e.g., TSC, NPCC, NERC).
2. For information purposes only, not used to judge application:
a. From transmitter: when networks upgrades are required, supply information on the nature and magnitude of the upgrades.
b. From IESO: information on other relevant impact(s) (e.g., line losses, congestion and congestion payments).</td><td>Alternatives not relevant</td></tr>
<tr><td>Development</td><td>1. Applicant’s responsibility to complete transmission rate impact assessment.
2. IESO’s and/or the OPA’s (or other need-justifying party) responsibility to provide evidence for any non-discretionary project:
• File cost-benefit analysis where proposed project is best compared to other viable transmission or non-transmission alternatives. For non-transmission alternatives their corresponding benefits need to be quantified and incorporated in the evaluation of the preferred transmission alternative on avoided cost basis;
• Existing published reports issued by the IESO and/or the OPA on regular basis can be used as evidence by the Applicant to justify the need for some of the projects e.g. load growth require reinforcement of existing transmission facilities or building new ones; and
• Corroborating evidence from the IESO, and where appropriate the OPA, regarding the mandatory reliability standards applicable for a project.
3. Applicant’s responsibility to justify cost effectiveness for any discretionary project:
• File cost-benefit analysis where proposed project is best compared to other viable transmission alternatives and non-transmission alternatives</td><td>1. Alternatives where feasible to be presented.
2. Number of alternatives provided: - smallest number consistent with conveying the major solution concepts.</td></tr>
</table>

Project Class	Information Requirements	Alternatives
	whose benefits need to be quantified and incorporated in the evaluation of the preferred transmission alternative on avoided cost basis. For discretionary projects the “doing nothing” alternative has to be included: • IESO’s and/or the OPA’s can provide evidence where a proposed project is selected as best compared to other viable transmission alternatives and non-transmission alternatives. Where the Applicant lists benefits of avoiding “non-transmission” alternatives such as a “peaking generation” or a “must run” generation requirement, their corresponding benefits need to be quantified and incorporated in the evaluation of the preferred transmission alternative on avoided cost basis.	