Ontario Energy Board
Staff Proposal

Minimum Filing Requirements for Transmission and Distribution Rate Applications and Leave to Construct Projects
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Chapter 1 Overview

The purpose of this document is to provide a single source of information about several minimum filing requirements dealing with electricity transmission and distribution rate applications and leave to construct projects. These include:

- Minimum filing requirements for electricity transmission and distribution companies’ cost of service rate applications, based on a forward test year
- Filing requirements for the 2nd generation incentive regulation mechanism for electricity distributors
- Minimum filing requirements for leave to construct electricity transmission projects under section 92 of the Ontario Energy Board Act, 1998 (the Act)
- Minimum 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)

The IPSP is a twenty-year plan “to assist, through the effective management of electricity supply, transmission, capacity and demand,” the achievement by the Government of Ontario of its goals in relation to electricity supply, transmission and conservation. The normal expectation is that significant transmission projects will be identified in the IPSP. The approved IPSP identifies the need for a project and will have an estimate of its cost. Refinement of the cost estimate is expected in the capital budget review of the rate setting process of the regulated transmitter (chapter 2 and 5). The need for the project is not re-evaluated; the forecast costs are examined. If this sequence of events occurs the transmission project reviewed under section 92 (chapter 4) is relatively limited to issues of detailed siting and review of updates to cost estimates provided in the transmitter’s budget review.

Chapter 2 details the minimum 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. These minimum filing requirements will be used by an electricity transmission or distribution company as the basis for filing a forward test year cost of service application. They form the minimum material that must be included in a rate application and an application that fails to provide all of the elements will be considered incomplete and will 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 will be drafted in 2006 and will be consistent with the Board’s Code developments related to an incentive rate mechanism. It is anticipated that this Code will provide a simple, practical, and mechanistic incentive rate adjustment, including the cost of capital to be used, for the years 2007 to 2010. 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 minimum filing requirements for the approval of a leave to construct electricity transmission projects under section 92 of the Act. The Board has the responsibility of approving some transmission facilities and setting transmission rates in the public interest.

Chapter 5 states the minimum 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, elements of these capital projects should 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. The intention is that this document 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 2 Minimum filing requirements for electricity transmission and distribution companies’ cost of service rate applications, based on a forward test year

2.1 Introduction

These minimum filing requirements are to be used for filing a forward test year cost of service application for transmitters and distributors. Companies should use these minimum 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 minimum filing requirements is not included in the filing, the application will be deemed incomplete and will not be processed until completed.

The OEB has established a multiyear electricity distribution rate setting plan. The schedule by which distributors will go through their rebasing review will be established through a screening process. An initiative will be started soon to determine how that screening will be implemented.

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 the last Board Approved Year. The variance analysis should also be made between the test year and the last year for which actual costs are available. 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.

That variance analysis will be guided, in part, by a comparison of costs among distributors. A process will be started shortly to develop the comparison methodology. The results of that initiative will identify additional areas where specific information will be required.

The Board’s minimum 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.

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 consider those commonly asked questions and include the information that is the subject of those questions in their initial filings.
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)
- Metric Units
- Average of monthly averages valuation method for items in rate base and capital base
- Total Capitalization 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 = Previous Year (Board Approved and actual values)
- 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 calculation of revenue sufficiency/deficiency should be based on proposed methodology, and the resultant impacts of the methodology change must also be provided
- Written Direct Evidence should be included before the data schedules
- The Board’s minimum 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 changes 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 the change in methodology 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 and found in the functionalized form in the cost allocation model with the financial statements and the RRR filings. The definitions of those accounts is contained in the accounting Procedures Handbook.
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, which deals with 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
- List of Affiliate Transactions in Historic Year, Bridge Year and planned or anticipated transactions during the Test Year including shared services, subsidiaries and related party transactions. The list should include dollar amounts of transaction and the basis on which amounts are determined
- Utility Organizational charts, down to and including the managerial level
- Corporate Organization Chart including information showing the extent to which the parent company is represented on the utility company board and the reporting relationships between utility management and parent company officials.
- 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)
  - Budget Process
  - Flow charts of approval process
  - Correspondence regarding Budget levels – goals, strategies and guidelines
  - 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
  - Utility
  - Parent Company
- Financial Statements – Utility 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 part of the 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 regulatory filings, the utility will file a detailed reconciliation of the financial results in the Annual Reports/Audited Financial Reports with the regulatory financial results filed in the applications and filed as RRR requirements.
- All parent and 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 both the Utility and the Parent Company
- 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 – Reports from DBRS or S&P.
- 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 Board approved, Historic Actual, and Bridge and Test years. Additional required statements for 1 and 2 include:

Continuity Statements (Year-end and are to include Interest during Construction & All overheads)
- Historical Actual to Bridge
- Bridge to Test Year

Variance Analysis

A written explanation is required for rate base related information when there is a variance greater than or equal to 10% or $500,000.
- Historical Board Approved v/s Historical Actual
- Historical Actual v/s Bridge
- Bridge v/s 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 accumulated by a written description.
- Customer Additions and System Expansion with PI values
- Average of Monthly Averages as has been provided should continue.

Capital Budget - Historic Year, Bridge Year & Test Year

- Capital Budget by project
  - Projects over $500,000 listing need, scope, related attachments, volumes and capital costs. Provide a detailed breakdown of starting dates and in-service dates; and for


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.

- Accumulated depreciation to gross assets 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 monthly averages ($)

B. **Prepaid Expenses**
   - Calculation of average of monthly averages ($)

C. **Miscellaneous Accounts Receivable**
   - Calculation of average of monthly averages ($)

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

E. **Security Deposits**
   - Calculation of average of monthly averages ($)

Other Items of Working Capital (itemized individually)
- Calculation of average of monthly averages ($) if applicable
2.4 Exhibit 3. Operating Revenue

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

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

1. Throughput Revenue

- Explanation of causes and assumptions for the demand 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 v/s Historical Actual- normalized
- Historical Actual- normalized v/s Bridge – normalized
- Bridge – normalized v/s Test Year

- For residential, general service, commercial and industrial customers, normalized average consumption historic actual and forecasted consumption per customer for past 10 years and forecasted average consumption for the Test Year.
- Explanation of large volume (contract) customer throughput forecast for Test Year and comparison of 5-Years of forecast v/s actual normalized, to evaluate accuracy of previous forecast. If Contract customer demand is not weather sensitive, then there is no need to provide this information.
- Explanation of net change in general service and contract 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).

3. Other Revenues

• Details and breakout of Other Revenues and a description of each of the revenue sources should be provided.
• Comparison of Actual revenues to Board Approved for Historical and Bridge years
• Detailed calculation of Rate of return on non-core delivery activities

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)
Written Direct Evidence to give further details of the budgets

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

- Breakdown of each on a departmental basis
- 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
- 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 v/s Historical Actual
Historical Actual v/s Bridge Year
Bridge Year v/s Test Year
A written explanation is required for operating cost related information when there is
a variance greater than or equal to 5% or $100,000, which ever 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

1.  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) Historical Year Board Approved, 2) Historical Years Actual, 3) Bridge Year, and 4) 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

Historic Year, Bridge Year & Test Year

- 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

Refer to Chapter 5 – Cost of Capital, 2006 Electricity Distribution Rate Handbook.

The requirements for cost of capital will be codified and brought into effect through the Board initiated Cost of Capital (EB-2006-0088), 2nd Generation Incentive Regulation Mechanism (EB-2006-0089) and Licence Amendment Proceeding (EB-2006-0087).

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

The 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

   B. Classification
      - rate base
      - cost

   C. Allocation
      - rate base
      - cost

   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

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 annual 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 blocks, seasons, zones 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, Bridge 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 2\textsuperscript{nd} generation incentive regulation mechanism for electricity distributors

NOTE: This Chapter will be drafted later in 2006 and will be consistent with the Board’s Code developments related to its multi-year electricity rate-setting plan for electricity distributors. It is anticipated that this Code will provide a simple, practical, and mechanistic incentive rate adjustment, including the cost of capital to be used, for the years 2007 to 2010. 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  Minimum filing requirements for electricity transmission projects under Section 92 of the OEB Act

4.1  Introduction

This document outlines the minimum 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.

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 minimum 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.

For a rate regulated transmitter 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, only the minimum filing requirements set out in section 4.3 in this Chapter are needed.

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 minimum 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.

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 kilometers 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

Minimum 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 or rates proceeding approved by the Board, only the minimum filing requirements set out in section 4.3 in this Chapter are needed.
For a rate regulated transmitter where a proposed project requires a leave to construct and that project had not been included in a Board approved IPSP or had not been included in a list of capital projects in the most recent rate hearing that has been approved by the Board, the minimum filing requirements are set out in section 4.3, section 4.4, and Chapter 5.

Rate regulated distributors applying for connection projects such as a transformation connection should follow the common minimum 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 the submission 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 minimum filing requirements for non-regulated entities reflect this risk structure.

4.3 Minimum 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 minimum filing requirements apply to projects, which are considered in a leave to construct proceeding.

The minimum 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 minimum filing requirements limit the discretion of the Board in terms of what information and evidence it may wish to see.

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. 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.

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 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: Minimum 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 minimum 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 minimum 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 minimum 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 kilometers 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 (TSC).

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.

<table>
<thead>
<tr>
<th>PROJECT CLASS</th>
<th>PROJECT NEED</th>
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<tr>
<td></td>
<td>Non-discretionary</td>
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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 for load growth or other changes to the system such as minimizing congestion on the transmission system.
- Connection projects are those for the sole purpose of providing connection of a customer to the transmission system, and include both line and transformation facilities.
- Sustainment projects are intended to maintain the performance of the transmission network at its current standard.

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 (NAERO in the near future) or by the Independent Electricity Market Operator (IESO);
- Need to accommodate new load (of a distributor or large user) or new generation (connection);
- To relieve system elements (transmission lines, circuit breakers, etc.) where the loading exceeded their capacities or where short circuit levels on these system elements exceeded their withstand capabilities;
- Projects identified in an approved IPSP;
- 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;
- Projects to meet system needs relying on best practices;
• 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 must be comprehensive, and, where appropriate, could be supported by evidence of the IESO and/or the Ontario Power Authority:

• where a proposed project is best compared to transmission alternatives, including “doing nothing”; and
• where the Applicant lists benefits of avoiding non-transmission alternatives such as a peaking generation facility, 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 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, 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.

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 cannot include “doing nothing” as an alternative. 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 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;
• 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.
# Appendix 2-A

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<td>Overhead Distribution Lines and Feeders - Right of Way</td>
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<td>Maintenance of Underground Conduit</td>
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<td>5150</td>
<td>Maintenance of Underground Conductors and Devices</td>
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<td>Maintenance of Underground Services</td>
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<td>Maintenance of Line Transformers</td>
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<td>Meter Reading Expense</td>
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<td>Miscellaneous Customer Accounts Expenses</td>
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<td>Supervision</td>
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<td>Community Relations - Sundry</td>
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<td>5415</td>
<td>Energy Conservation</td>
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<td>Miscellaneous Customer Service and Informational Expenses</td>
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<td>Demonstrating and Selling Expense</td>
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<td>5515</td>
<td>Advertising Expense</td>
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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

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).

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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>
<thead>
<tr>
<th>Project Class</th>
<th>Information Requirements</th>
<th>Alternatives</th>
</tr>
</thead>
<tbody>
<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>
</tbody>
</table>
| Connection    | 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). | Alternatives not relevant |
| Development   | 1. Applicant’s responsibility to complete transmission rate impact assessment.  
2. IESO’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 transmission alternatives.  
   - Existing published reports issued by the IESO 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 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 transmission alternatives, including “doing nothing”;  
   - IESO’s evidence where a proposed project is selected as best compared to transmission alternatives, including “doing nothing”; and  
   - where the Applicant lists benefits of avoiding “non-transmission” alternatives such as a peaking generation facility. Evidence from the IESO would be helpful which would corroborate the Applicant’s evidence quantifying that benefit. | 1. Alternatives where feasible to be presented.  
2. Number of alternatives provided: - smallest number consistent with conveying the major solution concepts. |