Manitoba Hydro

TRANSMISSION PLANNING & DESIGN DIVISION

SYSTEM PLANNING
DEPARTMENT

REPORT ON

MARGINAL TRANSMISSION & DISTRIBUTION COST ESTIMATES

SPD 04/05

Contents

Executive Summary

Objectives

This report has the following two objectives:

1) To develop a methodology for estimating marginal (or avoided) T&D costs.

2) To update the existing marginal (or avoided) T&D costs that were originally produced in the 1990 avoided cost study [4,5,7].

Recommendations

1) **The one year deferral (OYD) method should be used for marginal (or avoided) T&D cost estimates.**

   This method is developed on the basis of the deferral value of load-growth related capital costs due to a reduction in the forecasted system peak load (demand). In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth. The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecast annual peak load.

2) **The values in Table A should be used as long-term marginal (or avoided) T&D cost components.**

TABLE A

LEVELIZED MARGINAL (OR AVOIDED) T&D COSTS ($/KW/YEAR)*

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average (Mean)	45.44	22.09	40.93
Standard Deviation	6.19	2.12	1.60

***Notes:**

a) The values are levelized over the study period of 2004/05 to 2013/14.

b) The values are expressed in 2004 constant dollars and escalate at the inflation rate.

c) The averages (means) are considered as the generic marginal T&D cost components. The probability that the marginal cost falls within 1, 2, and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively.

d) The values are valid for a winter peak system.

e) The values are non-area-specific (i.e., do not vary by area).

f) The values do not include the replacement costs associated with the capital investments.

g) The values can be assumed to continue into the future beyond the planning horizon of 2013/14.

h) Although the values are derived for load reductions between 0 and 1 year's worth of load growth, it has been shown that their application can be extended to the case of larger load reductions (say, up to two times the annual load growth).

i) The values are valid for a real discount rate of 6.0% (without the inflation rate component). If the real discount rate is significantly different from 6.0%, they should be modified using the information provided in this report.

j) The values are valid only for transmission, subtransmission and distribution-circuit defined in this report.

The costs are based on the "T&D Capital Expenditure Forecast (CEF03-1)" for the period of 2003/04 to 2013/14 and the Corporate "Electric Load Forecast" for the same period. They are derived using the OYD method and a random load reduction stream that is defined as $\{\delta L_k\}=\{\lambda_k \Delta L_k\}$, where ΔL_k $(k=1,2,3,\cdots)$ is the forecasted load growth in year k and λ_k $(k=1,2,3,\cdots)$ is a random number uniformly distributed between 0 and 1.

3) **The marginal costs should be updated 5 years from now or earlier as needed.**

Results of Pevious Study

The last avoided T&D cost study was conducted in 1990. The avoided cost components produced in that study are $11/kW/Year and $11/kW/Year (in 1990 constant dollars) for transmission and distribution, respectively. They are significantly lower than those recommended in the present study. This is mainly attributed to the differences in the methods, assumptions and data used for the avoided cost estimates.

1. Introduction

For various purposes such as the evaluation of demand side management (DSM) programs and equipment losses, etc. [4,7], we need to estimate the additional (incremental) cost incurred by an increase in capacity and energy requirements, or equivalently the cost that can be avoided if not having to increase capacity and energy requirements. Such an incremental cost is labeled "marginal cost" or "avoided cost". The marginal cost for a power system is usually split into three system levels: generation, transmission and distribution (T&D). The marginal generation costs include both capacity and energy components; while the marginal T&D costs are capacity related only.

The term "avoided cost" was replaced by "marginal cost" in the report on "1996/97 Update to Marginal Costs", PP&O Report 97-5, prepared by Resource Planning & Market Analysis because the latter was judged to be more descriptive and useful for the Manitoba Hydro situation [7]. To be consistent with the current marginal costing practices, the term "marginal cost" was adopted in this report. The term "avoided cost", however, will occasionally be used for convenience, bearing the same meaning as "marginal cost".

In this report, we will first propose a methodology for marginal T&D costs, and then provide marginal (or avoided) T&D cost estimates for the Manitoba Hydro system. The results will supercede the existing avoided T&D costs originally produced in the 1990 avoided cost study [4].

2. Methodology

Marginal T&D cost seems to be a simple concept, but its detailed definitions and calculation procedures vary widely in practice depending upon the way it is perceived [1,2,4,6,8,9,10]. The marginal (or avoided)

2.2. General Deferral Concept

The deferral concept to be presented below is similar as the one used in the previous avoided cost study [4], which is on the basis that the load-growth related capital expenditures can be deferred if there is a reduction in the forecasted system peak load (demand).

Suppose the capital expenditures for year k, denoted by $\tilde{I}_k$, can be deferred by a time period, Δt_k, due to a load reduction, δL_k. The capital expenditures deferred to year $k+\Delta t_k$, after being adjusted for inflation, are equal to

$$\tilde{I}_k(1+j)^{\Delta t_k}$$

This amount of dollars is discounted back to year k as

$$\frac{\tilde{I}_k(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}$$

This indicates that the deferring of $\tilde{I}_k$ to year $k+\Delta t_k$ is equivalent to the spending of $\tilde{I}_k(1+j)^{\Delta t_k}/(1+d)^{\Delta t_k}$ in year k. Obviously, the saving (i.e. cost avoided) in year k is

$$\tilde{I}_k - \tilde{I}_k\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}} = [1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\tilde{I}_k$$

The deferral value, i.e., the present value of all savings over the study period, is

$$\Delta PV = \sum_{k=1}^{N}[1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\frac{\tilde{I}_k}{(1+d)^k} \tag{6}$$

Such a deferral value is also used in the Present Worth (PW) method [2,8,10].

The levelized marginal costs (or avoided) cost C_{avoid} determined by Eq. (8) or (9) is measured in constant-worth dollars. It can be converted to the "then-current" dollar value in year k as $C_{avoid}(1+j)^k$.

The two methods to be presented in the following sections are derived from the above concept. Their difference lies mainly in the restrictions imposed on the deferral time.

2.3. Load Reduction Streams

In the context of this report, a load reduction stream refers to a series of reductions in peak load (demand), which is represented mathematically as $\{\delta L_1, \delta L_2, \cdots, \delta L_N\}$. The marginal cost is affected by the type (shape) of load reduction stream. In this study, the following three types of load reduction streams will be considered:

- *Uniform load reduction stream*: It is defined such that the reduction in peak load is the same from year to year, i.e. $\delta L_k = \delta L$ for $k = 1,2,3,\cdots,N$.
- *Near-uniform load reduction stream*: It is defined such that its shape is similar to that of the annual load growth stream, i.e. $\delta L_k = \lambda \Delta L_k$ ($k = 1,2,3,\cdots,N$), where λ is a number between 0 and 1. Since the annual load growth usually does not deviate significantly from the average, this type of load reduction stream is referred to as near-uniform load reduction stream in this report.
- *Random load reduction stream*: It is defined such that the reduction in peak load varies from year to year in a random fashion. It is mathematically represented as $\{\delta L_k\}=\{\lambda_k \Delta L_k\}$ where λ_k ($k = 1,2,3,\cdots,N$) is a random number uniformly distributed between α and 1 with α being

[5] The "then-current" dollars include the effect of inflation, but the "constant-worth" dollars don't. The constant dollar cash flows can be brought forward or deferred without adjustment for inflation. For more detailed information, see Section 3.8.6 Inflationary Effects in "Principles of Engineering Economic Analysis" by A.J. Szonyi, et al. [3]. In Manitoba Hydro, "constant-worth dollar" is usually referred to as "constant dollar".

a fixed positive number smaller than 1. It covers all the possible types of load reduction streams in practice, including the above two types.

2.4. One-Year Deferral (OYD) Method

The method to be presented below may be viewed as a probability-based one. In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth.[6] The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecasted annual peak load.

Let us start with an example. Suppose the capacity of a substation is 40 MWA, the power factor is 1.0, and the expected peak loads of the station are 38.5 MW and 41.2 MW for 2010/11 and 2011/12, respectively. The expected load growth in 2011/12 at this station is 2.7 MW. The existing station capacity can meet the 2010/11 peak load but can not meet the 2011/12 one. The shortage or scarcity of capacity for 2011/12 is 1.2 MW, as shown in Fig. 1. Based on the above information, a new transformer has been planned for service in 2011/12. Now, a reduction of 1.5 MW in the peak load, for instance, is expected for 2011/12. Considering that the load reduction of 1.5 MW exceeds the capacity shortage of 1.2 MW for 2011/12, we can defer the installation of the new transformer from 2011/12 to 2012/13. This suggests that the load reduction needs not to reach at least one year's worth of load growth of 2.7 MW in order to cause a capital deferral!

[6] In the approach used in the previous avoided cost study [4,5], it is assumed that a reduction in load can not cause capital deferrals until it approaches a significant level. "Significant" is defined such that the size of load reduction reaches at least one-year load growth. Under such an assumption, we can not estimate the avoided costs due to small load increments. Besides, it is hard to obtain accurate avoided cost estimates unless the load reductions are chosen such that they are just "significant". As shown in this section, the "significant level" requirement is inconsistent with the practical situation.

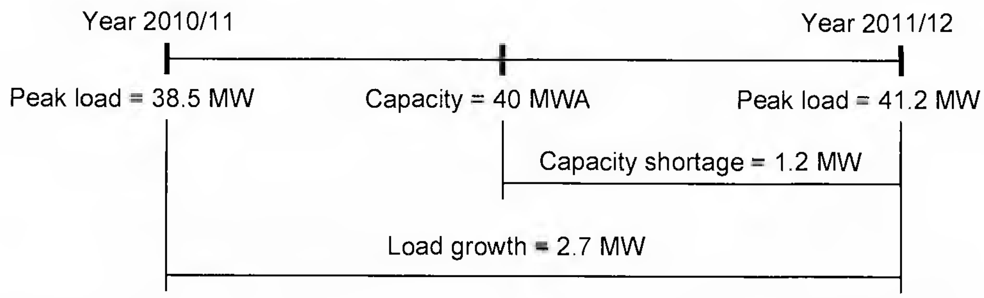

Fig. 1. Illustration of capacity shortage of a substation that is unable to accommodate the peak load in the year of 2011/12, assuming that the power factor is 1.0.

From a system-wide standpoint, the investments for year k are associated with capacity expansion of many facilities (e.g. lines, stations, etc.). The capacity shortage of each one could be anywhere between 0 and the annual load growth, ΔL_k. In other words, the capacity shortage is randomly distributed between 0 and ΔL_k. According to what has been observed from the above example, any load reduction, δL_k, even if it is less than ΔL_k, could possibly cause a capital deferral. Now the question is: What is the probability of capital deferral due to a load reduction of δL_k? To answer this question, we would like to look at the following three situations:

- For $\delta L_k / \Delta L_k = 0$ (no load reduction), the probability of capital deferral is 0%.
- For $\delta L_k / \Delta L_k = 1$ (the load reduction equal to the annual load growth ΔL_k), the probability of capital deferral is 100%.
- For $\delta L_k / \Delta L_k = 0.5$ (the load reduction is halfway between 0 and ΔL_k), the probability of capital deferral is 50%, which is based on the judgment that there is an equal chance for the capacity shortage to be above or below $0.5\Delta L_k$.

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Domestic items are further split into blanket and non-blanket categories. Blanket projects are typically smaller than $300,000 and not required to have a CPJ or CER. Non-blanket projects are typically between $300,000 and $2,000,000, and each of them has a CPJ and CER.

Some items in the TP&D and DP&D areas are load-growth related; those in the other five areas, however, are not driven by load growth and therefore are excluded from the marginal cost study.

3.5.2. Analysis of T&D Capital Expenditures

This section is to identify the load-growth related part of the TP&D and DP&D capital expenditures (see Appendix B). A load related capital item may be driven by several factors in addition to load growth. As rules of thumb, the following guidelines are used for splitting a capital item between load-related and non-load-related portions:

- Major item or non-blanket item:
  - 100% load related if it is mainly driven by load growth.
  - 0% load related if it is mainly driven by factors other than load growth.
  - 50% load-related if it is driven by load growth and other factors.
  - Other percentage based on judgment.
- TP&D domestic budget - blanket:
  - Transmission line additions & modifications: 50% load-related.
  - Station site acquisition: 50% load-related.
  - Property land right acquisition: 0% load-related
  - Others: 0% load related.

- DP&D domestic budget – station blanket: 75% load-related.
- DP&D domestic budget – distribution blanket:
  - Subtransmission (S/T) additions & modifications: 50% load-related.
  - S/T system – ice melting: 0% load-related.
  - Street lighting: 0% load-related.
  - Highway changes: 0% load-related.
  - S/T modifications – storm damage: 0% load-related.
  - System improvements: 80% load-related.
  - Customer service: 50% load related.
  - New & upgraded feeders: 50% load-related.
  - Underground residential dist: 50% load-related.
  - Defective cable replacements: 0% load-related.
  - Others: 0% load-related.

Note that the guidelines for splitting the DP&D domestic blanket items are based on the advice from Distribution Planning & Design at Winnipeg, Brandon and Selkirk.

The major items are analyzed on a project-by-project basis and the results are summarized in Appendix B.

Unlike major items, TP&D and DP&D domestic items include many small projects. The annual domestic budgets have been projected for future years within the planning horizon, but are not defined in detail. In such a situation, what we can do is to analyze the 2003/04 domestic budget, and assume that the result (i.e. load-related portion in %) will hold for the future years. The non-blanket items for 2003/04 are analyzed on a project-by-project basis and the blanket budget is analyzed by categories.

Several related issues have been discussed, which includes the marginal costs beyond the 10 planning horizon, the effect of the discount rate on the marginal cost, etc.

The marginal costs presented in the report are non-area specific and winter-peak-load related. The values in Table 6 are recommended as the generic marginal T&D costs. The range of 1, 2 or 3 standard deviations from the average may be chosen for sensitivity study.

It should be borne in mind that the marginal costs provided in this report may not be applicable in the situations where there is a very large load change (say, much larger than two times the annual load growth), or where the capacity expansion is based on the summer system peak load (demand).

Recommended future work is summarized below (but not limited to):

- To develop more sophisticated guidelines for extracting the load-growth related capital costs from the T&D Capital Expenditure Forecast;
- To update the marginal T&D costs every 5 years or on an as-needed basis;
- To develop an area-specific marginal T&D costing method if needed;
- To develop marginal costs for summer peaking distribution systems if needed.

7. References

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