Q. Throughout the Schedules of the Cost of Service Study, customer allocations are based on zero-intercept ratios. Please provide a copy of the reports or studies, together with all supporting data, that were used to develop these zero-intercept ratios.

A. Functionalization and classification ratios for distribution were primarily developed from studies and documents prepared by Foster Associates, Inc. and filed at Hydro's 2001 General Rate Application as NP-123. The response to the 2001 request is attached as file 2001 NP 123.pdf and contains the following documents:

(1) Study of Distribution System Cost Classification, Foster Associates, Inc., December 1996;
(2) Study of Distribution System Cost Classification, Foster Associates, Inc., December 1998;
(3) 2001 Update to the Zero Intercept Analysis:
  a. Memo from John Brickhill, Foster Associates, to Glenn Mitchell, Newfoundland and Labrador Hydro, dated April 23, 2001.
  b. Memo from Brian Chabot and Karen Morgan, Foster Associates, to John Brickhill, Foster Associates, dated April 12, 2001.

Also attached is Foster Associates' regression analysis file, PUB 6 ZeroInterceptAnalysis.xls.

~ Please Contact The Board For Excel File Referenced Above ~

A cross-reference summary between the Cost of Service Schedule 4.1 and these documents and files follows.

Cost of Service Schedule 4.1
Distribution Functionalization and Classification Ratios
Reference Summary

COS Sch. 4.1 Line/Col			**Reference**
L28,C7	Substation Structures and Equipment		Study of Distribution System Cost Classification, Foster Associates, December 1996: Page 28, Refer to 2001 NP 123.
L29 L30,C2 L31,C2	Land & Land Improvements by Subfunction: Primary Secondary	 85.0% 15.0%	Based on historical knowledge and first used in the 1992 COS study.
 L30,C9 L38,C9	Customer Component: Primary Conductor	 11.3%	This percentage is a summary of the two subfunctions related to primary conductor which are: three-phase and other. Three-phase is 72.76% of the total primary conductor cost and is considered 100% demand-related (Study of Distribution System Cost Classification, Foster Associates, December 1998: Appendix C, p.4, Refer to 2001 NP 123). The remaining 27.24% is subject to the ratios determined from the conductor zero intercept analysis. Foster Associates' Excel file: PUB 6 ZeroInterceptAnalysis.xls Conductor Data worksheet indicates 41.7% customer component. Calculation Summary: Total / Demand / Custmr Primary Conductor – Three-phase 72.7% / 100.0% / 0.0% Primary Conductor – Other 27.2% / 58.3% / 41.7% Primary Conductor – Total 100.00% / 88.7% / 11.3%
 L31,C13 L41,C13	Customer Component: Secondary Conductor	 41.7%	Memo April 12, 2001 from Brian Chabot and Karen Morgan to John Brickhill indicates 41.6% for conductor. (Refer to 2001 NP 123) Foster Associates' Excel file: PUB 6 ZeroInterceptAnalysis.xls Conductor Data worksheet indicates 41.7%, used in the COS.
 L32,C8 L32,C9 L32,C12 L32,C13	Land & Land Improvements: Primary Demand Primary Customer Secondary Demand Secondary Customer	 75.4% 9.6% 8.7% 6.3%	 L30,C2 x L30,C8 L30,C2 x L30,C9 L31,C2 x L31,C12 L31,C2 x L31,C13
L33 L34,C2 L35,C2 L36,C2	Poles by Subfunction: 3 Phase Primary Other Primary Secondary	 41.2% 36.4% 22.4%	Study of Distribution System Cost Classification, Foster Associates, December 1996: Appendix D: Calculation of Split of Pole Investment Between Primary and Secondary (Refer to 2001 NP 123).
 L35,C9 L36,C13	Customer Component: Poles: Primary and Secondary	 54.3%	Memo April 12, 2001 from Brian Chabot and Karen Morgan to John Brickhill (Refer to 2001 NP 123) Foster Associates' Excel file: PUB 6 ZeroInterceptAnalysis.xls Pole Data worksheet
 L37,C8 L37,C9 L37,C12 L37,C13	Poles: Primary Demand Primary Customer Secondary Demand Secondary Customer	 57.8% 19.8% 10.2% 12.2%	 L34,C2 x L34,C8 + L35,C2 x L35,C8 L35,C2 x L35,C9 L36,C2 x L36,C12 L36,C2 x L36,C13

Cost of Service Schedule 4.1 Distribution Functionalization and Classification Ratios Reference Summary			
COS Sch. 4.1 Line/Col			**Reference**
L39,C8	Submarine Conductor: Primary Demand	100%	Study of Distribution System Cost Classification, Foster Associates, December 1996: Page 28, Refer to 2001 NP 123.
L40,C11	Customer Component: Transformers	63.9%	Memo April 12, 2001 from Brian Chabot and Karen Morgan to John Brickhill (Refer to 2001 NP 123) Foster Associates' Excel file: PUB 6 ZeroInterceptAnalysis.xls XMR Regr Output worksheet
L42-43	Customer Component of Services and Meters:	100%	Study of Distribution System Cost Classification, Foster Associates, December 1996: Page 29, Refer to 2001 NP 123.

Q. Provide the reports on the studies undertaken in 1996, 1998 and 2000 on the distribution system cost classification (JAB, page 2, lines 10-22).

A. The requested reports on the studies undertaken in 1996, 1998, 2000 on the distribution system cost classification are attached.

NP-123

STUDY OF DISTRIBUTION SYSTEM

COST CLASSIFICATION

Prepared For

NEWFOUNDLAND AND LABRADOR HYDRO

FOSTER ASSOCIATES INCORPORATED

ECONOMIC CONSULTANTS

Prepared by

FOSTER ASSOCIATES, INC.
Washington, D.C.

December 1996

TABLE OF CONTENTS

I. INTRODUCTION

A. Purpose and Scope

The purpose of this report is to explore the extent to which distribution costs should be classified as customer related with the remainder classified as demand related. The scope is limited to the requirements for an embedded-cost-of-service analysis and, therefore, may not be appropriate for a marginal or long-run incremental cost analysis.

B. Present Conditions

The requirement for this study arose from Item No. 19 of the Public Utilities Board recommendations in their report as an outcome of the 1992 Generic Hearing. Item 19 states

> [t]hat Hydro's proposed classification of distribution cost be accepted for interim use and that Hydro prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral.

It is presumed that Mr. George Baker's pre-filed testimony, the Company's evidence, and the transcript of the cross-examination of Dr. Robert H. Sarikas and Mr. Richard A. Bellin on this subject forms the basis for that recommendation by the Board.

Mr. Baker in his pre-filed testimony, in response to a question regarding distribution-cost classification, states that

> [s]ome distribution costs correlate with the number of customers served. To reflect this, it is normal to classify service and meters entirely as customer cost. In addition, poles, wire and sometimes distribution transformers are classified partly as customer cost. All other distribution plant, if not specifically assigned, is normally classified to demand.

In response to how such costs should be classified between demand and customer, Mr. Baker further stated that

> [a]mong recognized methods, the main alternatives are the zero intercept and minimum system methods. The zero intercept method is inaccurate by reason of the fact that it only classifies the marginal cost of demand as demand cost and classifies all other cost as customer cost. The minimum system method is even worse; it only classifies a part of the marginal cost of demand to demand. For this reason, the proportion of customer cost is usually overstated where recognized analytical approaches are used, typically varying between about 45% and 70%. For such reasons some utilities prefer to split costs on a judgmental basis.

In commenting on Hydro's distribution transformer analysis, Mr. Baker agreed that the result obtained by Hydro using the zero-intercept approach, a customer component of 23.5 percent of plant cost was realistic; however, he expressed reservation about the methodology. He believed that the weight and therefore the cost of the transformer is derived from the voltage class and is therefore a consequence of demand. He ultimately recommended an analysis that classified all transformers to demand.

With respect to pole investment, Mr. Baker concluded that Hydro's zero-intercept approach for poles understated the customer-cost percentage for that item. His proposed analysis would classify all lines between the substation and load center as demand related. The customer component would be based on the ratio of the per-mile cost of a line suitable for zero demand conditions to the current cost per mile of existing lines not included in the portion of line between substations and the load center.

II. INDUSTRY PRACTICE

A. General

This chapter of the report describes a research of the literature with respect to distribution system cost classification and a review of Canadian electric utility practice in this regard.

B. Review of Literature

The review of literature encompasses the few textbooks and technical papers dealing with the issue of distribution-system cost classification.

The text by Davidson states that

> [c]ustomer or consumer costs will include (a) that part of the total cost of the distribution network that varies with the number of customers and is not attributable to variation in the maximum rate of consumption; (b) the current direct costs incurred when an additional customer desires service, such as metering expenses, bookkeeping and collection expenses, service wiring, etc.; and (c) the cost of installation and connection incurred before the beginning of service to the new customer (though possibly amortized only in the course of time). Customer costs will vary with the number of customers, given the total kilowatt hours sold a year and the maximum rate of consumption in kilowatts. Customer costs represent the marginal costs of adding another customer to the utility system.[1]

Davidson amplifies this later in his text when he states that

> [c]ustomer costs are those that vary with the number of customers and represent the marginal cost of adding another customer to the utility system. This cost element can be recovered by having a fixed charge on each customer—a fixed monthly customer charge, payable whether or not the consumer uses any electricity during the month as long as he is connected to the utility system. Installation and connection costs would be charged to the utility system. Customer

[1] Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity*. (Baltimore: The Johns Hopkins Press, 1955), pg. 62.

> costs would not be the same for all customers of a utility because the investment in meters, for example, varies according to the size of the customer's expected maximum load; also the cost of reading meters would vary according to customer density.[2]

The well-known text by Caywood states that customer cost

> . . . varies with number of customers served and includes investment charges and expenses relative to a portion of the general distribution system, service drop or other local connection facilities, metering equipment, meter reading, billing, and accounting.[3]

Caywood points out that customer cost includes all cost of service, meters, customer accounting and collecting expenses, and a portion of distribution lines, line transformers, general plant, sales promotion expenses, and administration and general expenses.[4]

He also ascribes a relationship between customer and area costs:

> The cost of adding loads is less than the accumulated average, assuming a constant price level; the difference or so-called residual cost can be labeled a "customer" or "area coverage" cost. Local facility cost may be partly independent of and partly dependent upon a customer's load. The independent part can be classed a customer cost, while the dependent part can be treated on a kilowatt basis with no diversity.[5]

The text on costing and pricing published by the American Gas Association notes that

> The closer a plant item (*e.g.*, a meter and service line) is located to a customer, the more that particular item is related to the specific requirement of that customer. Thus, the customer component of distribution costs reflects the

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[2] Ibid., pg. 181.

[3] Russell E. Caywood, *Electric Utility Rate Economics.* (New York: McGraw Hill, 1956), pg. 26.

[4] Ibid., pg. 149.

[5] Ibid., pg. 172.

theoretical distribution system that would be needed to serve customers at nominal or minimum load conditions.[6]

Customer cost are defined as "invariant with respect to consumption. They are costs incurred to serve a customer even if the customer does not use the service at all."[7]That reference notes that customer costs include local connection facilities, metering, including billing and accounting, and a portion of the distribution system. It is also acknowledged that these costs are lower for a residential customer than for an industrial customer who may have an expensive transformer and switching equipment devoted exclusively to its use.[8]

Bonbright notes that the controversial aspect of customer costs is the inclusion of a substantial fraction of the annual maintenance and capital costs of the low voltage distribution system, equal to the estimated annual costs of a hypothetical system of minimum capacity. He notes that these customer cost are defended on the ground that, since they vary directly with the area of the system (or else with the lengths of the distribution lines), they therefore vary directly with the number of customers. He also describes the zero-intercept method. He then goes on to say that

> [w]hat this last-named cost imputation overlooks, of course, if the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.
>
> While, for the reasons just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer

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[6] AGA Rate Committee, *Gas Rate Fundamentals*, 4th Ed. (Arlington: American Gas Association, 1987), pg. 136.

[7] James C. Bonbright, *et al.*, *Principles of Public Utility Rates*, 2nd Ed. (Arlington: Public Utilities Reports, Inc., 1988), pg. 401.

[8] Ibid.

> ground. For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the **remaining** cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.
>
> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[9]

Comment

A review of the referenced paper by Lessels provides cause to believe that Bonbright, *et al.*'s confidence in its relevance may be misplaced.[10] Mr. Lessels, an employee of the U.S. Rural Electrification Administration (REA) limited his analysis to electric distribution borrowers of that institution. The REA, which provides low-cost loans to cooperatives for the purpose of extending electric service in rural areas had essentially accomplished its objective of providing service to all farms by the mid-1950s. Mr. Lessel's database covers the period from 1971 through 1978. In the period starting in the mid-1950s, the number of farms began a decline (average size of the farm increased). Many of the farmhouses, no longer occupied by farm families, however, continued to be used for residential purposes. Customer growth of the REAs in the 1970s was primarily in the areas adjacent to the towns and cities. Since these customers were closely spaced as compared to the original farms in rural areas, there is little wonder that investment per customer, as well as expense per customer, declined, leading to Mr. Lessel's conclusion that the costs were not correlated with the change in year-round farm and residential

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9 Ibid., pg. 491-2.

10 David J. Lessels, "The Economics of Electric Distribution System Costs and Investments," *Public Utilities Fortnightly*. Dec. 4, 1980, pg. 37–40.

customers. This issue will be discussed at greater length in Chapter III of this report. It is interesting to note that Bonbright goes on to state that "[i]n actual practice the vast majorities of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."[11]

A paper by Sterzinger claimed that the use of a minimum system resulted in an overallocation of costs to low-use residential customers because it is possible that such customers are capable of supply from a minimum system.[12] However, their demand, while less than average, nevertheless results in an additional allocation of cost to that customer class.

Comment

The argument presented by Sterzinger would presumably favor the zero-intercept method over the minimum-plant method.

A recent, and to some degree authoritative, text dealing with customer costs in general has been published by the National Association of Regulatory Utility Commissioners (NARUC). It devotes two chapters to this topic.[13] The tables in Chapter 6 thereof call for all services, meters, and property on customers' premises to be classified entirely as customer related. A portion of distribution and land rights, structures and improvements, poles, overhead and underground conductors and conduits, and line transformers are to be classified in part as customer related. In general, related operating and maintenance expenses follow plant, except that customer account expenses, customer service and information expenses, and sales expenses are classified as customer related. The two methods used to determine the demand and customer components of distribution facilities are the "minimum size of facilities method" and the "minimum intercept cost method."

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[11] Bonbright, *et al.*, pg. 492.

[12] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," *Public Utilities Fortnightly*. July 2, 1981, pg. 30-32.

[13] Staff Subcommittee on Electricity and Economics, *Electric Utility Cost Allocation Manual*. (Washington, National Association of Regulatory Utility Commissioners, 1992), Ch. 6 and 7.

In applying the minimum size method, the installed cost of a minimum height pole is multiplied by the total number of poles to find the customer component. For overhead conductors, the cost of a two-conductor minimum size circuit-mile is multiplied by the total number of circuit miles to determine the customer component. The line transformer component is determined by multiplying the total number of transformers by the cost of a minimum size transformer. It is pointed out that the technique can be applied to services by multiplying the total number of services by the cost of a minimum-size service.[14]

The NARUC manual states that the minimum intercept method "[i]n most instances is more accurate, although the differences may be relatively small."[15] The technique recommended for poles would require historic cost data by height and class of pole, which is normally not available from the accounting systems of North American utilities.[16] Variants of the recommended approach may be feasible.

In a critique of the two approaches, the authors point out that the minimum system, but not the minimum-intercept method, may result in a portion of demand not being included in the customer component.

C. Regulatory Commission Treatment of Customer-Related Cost

This section describes the pronouncements of various U.S. state regulatory commissions dealing with customer cost issues that have appeared in the rate orders of electric utilities under

[14] That approach does not take into account the fact that the larger services may be related to customer classes other than residential.

[15] Ibid., pg. 92.

[16] The recommended technique is as follows:

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by crating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

their jurisdiction.[17] In addition, a number of State Commissions have approved the use of the minimum-size method, and the zero-intercept method for gas distribution systems.

Connecticut

The Connecticut Department of Public Utility Control in its Order stated that "Distribution costs are driven by the number of customers served and the kilowatts of demand imposed by those customers." It discussed the features and methodology of the minimum-size method and the zero-intercept method, and noted that the minimum-intercept method has been recognized by the Department as an appropriate method and had been used by Connecticut Power & Light (CPL) in previous cases. CPL had requested permission to substitute the minimum-size methodology because of the Department's concern with what it regarded as deficiencies in CPL's use of zero-intercept method. In this case, the Department was critical of the minimum-plant methodology used by CPL, alleging that excessive sizes of poles, conductors, etc. were used. The Department stated that the minimum-size system should represent a theoretical system comprising minimum-size units of plant actually used and not necessarily conforming to current construction standards or practice. *Connecticut Power and Light Co.*, Docket No. 88-05-25, December 21, 1988.

In a later case, Connecticut Light and Power Co. (CLP) submitted a customer cost analysis based on both the minimum-size and zero-intercept methods. The two methods produce similar results on a totalized-plant basis. The distribution component for the minimum-size methodology was 52.9 percent, and 52.4 percent for the zero-intercept method. With respect to the two methods, the Department noted that the results for individual distribution accounts showed greater variations.

The Department stated that its concern with what it believes were deficiencies in CLP's application of the minimum-intercept methodology, combined with the fact that the minimum-size methodology requires less data, is easier to apply, is more readily understood, and is less

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[17] The most generally used source is the data published by *Public Utility Reports*.

costly to perform, led it to grant CLP's request to use the minimum-size method on an interim basis.

The Department believes that the simplicity of the minimum-size methodology together with its producing results similar to the much more complex minimum-intercept methodology, warrants its continued use by CLP in future cost studies.

The Department believes that some tangible portion of the distribution system rightfully should be allocated on the basis of customers served. The issue is should the minimum system lean toward what could be characterized as the minuscule system concept or should it more closely reflect the smallest plant sizes actually used.

The Department rejected the minuscule system concept and supported a minimum system that perhaps should be leaner than that proposed by the Company. *Connecticut Light and Power Co.*, Docket No. 90-12-03, Order dated August 1, 1991.

Florida

The Commission pointed out that its policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer related. The Industrial Intervenors and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer related, using the minimum-distribution-system concept. The Commission stated that there is a fundamental flaw in this proposal in that only part of the **distribution** system is classified as customer related. None of the subtransmission and transmission system would be classified as customer related. Hence, customer served at primary voltage through dedicated substations, and customers served at higher voltage would not pay for any of this network path.

It therefore reaffirmed its original position of classifying only service drops and meters as customer related. *Gulf Power Company*, Case 891345-EI, Order No. 23573, dated October 3, 1990.

The Commission rejected the concept of a minimum distribution system, stating that reliance on such a mechanism is speculative at best. The Commission stated that the appropriate customer charge should be based upon the cost of the meter, service, drop, meter reading, and basic customer-service costs exclusive of uncollectibles. *Tampa Electric Company*, Docket No. 80011-EO(CR), Order No. 9599, dated October 17, 1980.

Maine

The Commission stated that when allocating distribution plant between demand and customer components, it is appropriate to include in customer charges the cost of a minimum system, and such will not be unfair to low-usage customer, as the customer charge is not designed to reflect each customer's minimum demand but is to cover the costs of the system design to meet minimum safety and service requirements. *Central Maine Power Co.*, Docket No. 80-66, Order dated September 11, 1985.

The following discussion relates to a judicial review by the Maine Supreme Court of an Order of the Maine Public Utilities Commission. The Court discussed a number of issues, including customer cost. The Company used the minimum-size method in its analysis and that approach was approved by the Commission. Various intervenors objected and stressed statements in Dr. Bonbright's book that such costs are unallocable. The judge pointed out that Bonbright criticized the inclusion of such costs in demand costs with equal fervor. The NARUC cost-allocation manual, which was placed in evidence, recognizes two methods of determining the customer-cost component of distribution plant: the minimum-size and minimum-intercept methods. The judge pointed out that the intervenor witness conceded on cross-examination that his proposal to classify distribution-plant costs to demand-related cost was not recognized in the NARUC manual while use of the minimum-size was. The judge concluded that the Commission, faced with the dilemma of whether to treat such cost as customer related or demand related, was entitled to exercise reasonable discretion in selecting a methodology. He stated that "adoption of the policy urged by the intervenors of classifying the costs of the minimum-distribution system to the energy (demand) charge would be equally imperfect, and Commission discretion must therefore carry the day." *Central Maine Power Co. v. Maine Public Utilities Commission, et al.*, Case 402, A.2d 153, Order dated August 6, 1979.

New York

The rulings of this Commission differ in terms of the utilities under its jurisdiction.

The Commission adopted a proposal that eliminated minimum grid costs as customer related since the hypothetical minimum grid costs were considered to be common to both the demand and customer components and, as such, not allocable between them. This was stated in response to the testimony of Mr. George Sterzinger, discussed *supra*.

The Commission further stated that "while both methods—minimum size and zero intercept—are reasonable, the zero-intercept method is generally preferable." *Central Hudson Electric & Gas Corp.*, Case 27636, Opinion 82-11, May 19, 1982.

In the case of Rochester Gas & Electric Co., the Commission upheld an allocation of electric service costs based on a system with minimal capacity. *Rochester Gas and Electric Co.*, Case 28896, Opinion No. 85-13, July 9, 1985.

The Commission, over the objections of intervenors, approved the methodology used by Niagara Mohawk Power Corp., of calculating non-demand-related distribution costs (identified as customer costs by Niagara). That methodology treats capitalization-installation costs (labor costs) as customer costs, and all other costs are demand related. The Commission suggested an alternative name such as "service" or "delivery" costs. *Niagara Mohawk Power Corp.*, Case 29327, *et al.*, Opinion 87-3, March 13, 1987.

North Carolina

The Company proposed to discontinue use of the minimum system technique and was supported in this effort by the Commissions staff. The Commission disagreed and concluded that the minimum system technique should not be discontinued at this time. It noted that the minimum system technique allocates more of the distribution plant to residential customers and less to industrial customers. It further stated that the method is conceptually sound, even if the results of such a technique are not fully reflected in the basic customer charges. *Carolina Power & Light Co.*, Docket E-2, Sub. 526, August 27, 1987.

Pennsylvania

The Commission was satisfied that an electric company classified a portion of distribution plant as customer related, allocating customer costs to classes on a customer base. It rejected a claim that any distribution plant should be classified as energy related. *Pennsylvania Public Utility Commission v. Pennsylvania Electric Co.*, Case R-822250, *et al.*, October 14, 1983.

The Commission concluded that since certain costs have no relationship to the minimum or maximum capacity required for service, it is therefore appropriate to allocate distribution-plant costs on a demand-customer basis. *Pennsylvania Public Utility Commission v. Duquesne Light Co.*, 59 PaPUC 67, R-842583, January 24, 1985.

Utah

The Commission rejected the minimum distribution system for satisfying distribution costs, since that system would result in a double allocation of these cots to low-use customers, but found that it would be reasonable, now and for the future, to classify each distribution system account as demand cost or customer cost, based upon engineering analysis. *Utah Power & Light Co.*, Case No. 79-035-12, Order dated March 7, 1983.

Wisconsin

After reviewing various proposals for the calculation of customer-related cost calling for the inclusion and exclusion of various components of the distribution system, the Commission concluded that a customer-cost determination incorporating billing expenses, cost of the meter, service line, and a portion of the distribution plant that varies with the number of customers is considered appropriate and is to be utilized in the rate design. *Madison Gas and Electric Co.*, Case 3270-UR-1, Order dated November 9, 1976.

D. Canadian Practice

Data with respect to the calculation of customer-related cost by the following Canadian electric utilities was obtained by personal contact or a review of cost-allocation studies prepared by them.

Nova Scotia Power Corporation

The approach used by Nova Scotia Power Inc. to split distribution cost between demand and customer related in its cost study submitted to the Nova Scotia Utility and Review Board, and covering the time period for the year ending December 31, 1996 relies on percentages based on construction and engineering estimates. The investment in poles and wire is split between primary and secondary distribution. All primary distribution is treated as demand related while secondary distribution is treated as customer related. In the analysis, 30 percent of the poles and wire is estimated to be primary, while the remainder is split 50 percent to primary and 50 percent to secondary. The resulting demand/customer split for those two components is 65 percent to demand-related and 35 percent to customer-related cost.

Underground facilities were classified to demand and customer cost in the same proportion as poles and wires. Line transformers are treated as 100 percent demand related, while services and meters are regarded as 100 percent customer related. Line transformers are allocated to customer classes using non-coincident demands. Services are allocated to rate classes on a weighted-customer basis.

Edmonton Power

Edmonton Power's cost-of-service study is prepared for internal purposes. It is not subject to regulatory approval. The methodology described is that used in the latest study. However, the methods are under review and may change.

Distribution substations are classified 50 percent to demand and 50 percent to on-peak energy. Overhead and underground primary lines, including poles, are also assigned 50 percent to demand and 50 percent to on-peak energy. Line transformers, secondary lines, service and meters are classified and allocated based on specific assignment for a sample of customers.

Newfoundland Power

Distribution substations are classified 100 percent to demand-related cost. Overhead and underground primary lines are classified 67 percent to demand-related cost and 33 percent to customer-related cost based on use of the minimum-plant method. Line transformers are classified 75 percent to demand-related and 25 percent to customer-related cost based on use of the zero-intercept method. Overhead and underground secondary lines, including poles, are assigned 67 percent to demand-related and 33 percent to customer-related cost. Services and meters are classified 100 percent to customer-related cost.

Hydro Quebec

Distribution substations are classified 100 percent to demand-related cost. Overhead primary lines (exclusive of poles) are classified 81.6 percent to demand-related and 18.4 percent to customer-related cost based upon the use of the minimum-plant method. Underground primary lines are classified 86.3 percent to demand-related and 13.7 percent to customer-related cost based upon the use of the minimum-plant method. Poles used to support primary lines are classified 10.3 percent to demand-related and 89.7 percent to customer-related cost based on the use of the minimum-plant method. Line transformers are classified 55.5 percent demand related and 44.5 percent customer related based on the minimum-plant method. Secondary lines (exclusive of poles) are classified 81.5 percent to demand-related and 18.6 percent to customer-related cost based upon use of the minimum-plant method. Poles used to support secondary lines are classified 11.3 percent to demand-related and 88.7 percent to customer-related cost based upon use of the minimum-plant method. All services and meters are classified 100 percent to customer-related cost.

SaskPower

Substations are classified 100 percent to demand-related cost. Three-phase feeders are classified 100 percent to demand-related cost. Urban single-phase primary lines are classified 36.5 percent to demand-related and 63.5 percent to customer-related cost based on the zero-intercept method. Rural single-phase primary lines are classified 19.0 percent to demand-related and 81.0 percent to customer-related cost using the zero-intercept method. Line transformers are classified 39.0 percent to demand-related and 61.0 percent to customer-related cost using the zero-intercept method. All secondary lines, services, and meters are classified 100 percent as customer-related cost.

New Brunswick Power

Distribution substations are classified 100 percent as demand related. All primary lines, including poles, are classified 50 percent demand related and 50 percent customer related based upon consultant's recommendations. Line transformers are classified 75 percent demand related and 25 percent customer related on the same basis. All secondary lines, including poles, are classified 50 percent demand related and 50 percent customer related based upon consultant's recommendations. Services are "not applicable." Presumably, they are customer owned or included elsewhere. Meters are classified as 100 percent customer related.

B. C. Hydro

Distribution substation plant and transformers which are sized to meet the peak demands of customers are classified 100 percent to demand. Primary lines are classified to demand and customer in proportion to a special study that assigned distribution feeder lines 100 percent to demand related and primary line extensions 100 percent to customer related. Distribution-related operating and maintenance expense, depreciation expenses, grants and taxes and related interest and net income expenses are classified to demand and energy in the same proportions as the classification of distribution plant. Customer accounting costs and other customer services costs are classified entirely as customer.

III. APPLICATION OF ALTERNATIVE METHODOLOGIES

A. General

The emphasis in the literature appears to be upon statistical relationships rather than upon an approach that would attempt to identify a causal relationship. A causal relationship can be established by observing the distribution construction required when new or added customers request service. The response will depend on a number of factors such as the class of customer (*e.g.*, residential, small general service, or large general service), the extent to which the area is already served, design practices, and the nature of the utilities' extension policy.

If we choose the residential customer class, since it is most numerous, and assume that service is provided to 100,000 residential customers and that the annual customer growth rate is 1.5 percent, the number of added customers each year will be 1,500. It is reasonable to expect that these customers will fall into the following categories:

- New customers in new multi-family apartments ranging from four customer structures to high-rise (12 or more stories) buildings. The smaller buildings will be served from a transformer-secondary system similar to that used to supply single family homes. A single service wire may supply all of the individual customer meters. A high-rise building may entail a single or three-phase primary cable installed in duct furnished by the building owner, with transformers located on the lower floor, the middle floor and the top floor. Secondary in duct furnished by the building owner will supply customer meters on every third floor.

  The supply of the smaller apartment building requires the extension of the primary system to serve the distribution transformer and the construction of secondary voltage lines if there are a number of similar small apartments in close proximity. The service wire to the apartment buildings and the installation of the required meters completes the construction project. See Figure 1. That figures assumes overhead construction. With underground construction a pad-mounted transformer would be installed at the same location in the transformer pole. The primary and secondary underground cable, and service cable would follow the same route as the overhead system.

A high-rise building supply is merely a vertical equivalent of the horizontal underground system that would be used to supply the individual apartment buildings.

- New customers in single family residences in a new residential subdivision. A subdivision could include an arrangement with only three or four lots, or many hundreds of lots, depending upon the size of the development. As an example, service could be supplied to only three homes in a 30-lot subdivision. The system could be built initially to serve the full development of 30 lots; however, it is possible that only three have been sold and have homes built thereon.

- New customers in single family residences in existing residential subdivisions. In that event, the only construction required is the installation of a service and meter for each residence.

- New customers in rural areas adjacent to a single-phase primary line. This may require only the installation of a distribution transformer on an existing pole, plus a service and meter. If the customer is located some distance from the existing line, it may be necessary to extend the primary line or construct a secondary line to reach the customer.

This list does not cover all the possible contingencies that may arise in supplying the total of 1,500 new customers. The average annual cost of supplying the added customers will vary considerably; however, for a given category, say single-family residences, it will tend to be about equal to the cost of a subdivision with 95 to 100 percent of lots served. The low cost of supply in an existing subdivision is balanced out by the high cost of a partially developed or undeveloped new subdivision.

The question arises as to the cause of cost. In incremental terms, the customer related cost is the full cost of connecting the added customers to system, including all of the aforementioned facilities. If these new customers purchased no energy, the reimbursement required to save the existing customers harmless would be the annual revenue requirement of these added facilities. Thus, in incremental terms, a "minimum" system has no relevancy. The concept of a minimum system as a measure of customer related cost, with the cost of capacity equal to the excess of that minimum amount, is limited to embedded cost analyses.

Mass statistics can create confusion. Some years ago, Con Edison of New York reported that its distribution system cost was increasing at a substantial rate, with no concomitant increase in the total number of customers served. What was happening was a very rapid growth in the number of customers served at substantial cost in affluent Westchester County in the same timeframe as the wholesale elimination of customers in the Bronx, which had the appearance of a war zone.

British economics literature refers to the concepts of "extensive" and "intensive" cost. The term "extensive," in this instance, would refer to the cost of supplying additional electric customers. The cost would have to cover their added demand imposed on the main primary feeder, distribution substation, transmission system, and generation, along with the investment and expense involved in extending the primary lines, installation of line transformers, secondary lines, services, and meters, as well as customer accounting and collecting. A like increase in demand, caused by an increase in consumption on the part of existing customers would involve only potential reinforcement of the existing distribution system, and the cost of transmission and generation. Since meters and services are generally sized for a large-use customer, the reinforcement will generally be limited to the addition of line transformer capacity and minor primary-line reinforcement. As an example, no additional poles will be required since all customers are served.

The foregoing discussion provides a reasonable basis for assuming that added customers will cause an increase in distribution investment whenever the new residence or business is located in an unserved area. Thus, there is a conceptual basis for recognizing customer-related cost in embedded- and incremental-cost analysis.

B. Alternative Classification of Primary Lines and Poles

Mr. George Baker, in his pre-filed testimony, recommended that all lines between the substation and load center be classified as demand related. A problem arises in that the "load center" is not defined. In the past, it was commonplace for utilities to construct so-called "express" feeders between the substation and the load center. The primary lines then extended in each direction from that point. Current practice is to not construct "express" feeders but instead to serve load throughout the length of all primary lines.

The three-phase feeder portion of the primary distribution system, in terms of cost behavior, responds to the capacity requirement of the load created by the addition of customers, as well as the additional consumption of existing customers. Thus, it can serve as a proxy for the so-called "express" feeder mentioned by Mr. Baker. The remaining single and two-phase and neutral laterals can then be classified between demand-related and customer-related cost in the usual fashion.

Based on our request, the Distribution Engineering planning group of Newfoundland Hydro developed statistics relating to the aggregate length of 4.16, 12.5 and 25 kV feeders in terms of three-phase, two-phase, and one-phase segments for each circuit. Statistics with respect to the total length of secondary distribution lines were also developed. See Appendix A to this report. Thus, it is possible to more accurately split distribution investment between primary and secondary lines, as well as provide a split between three-phase lines and single- and two-phase and neutral laterals.

It is proposed that all three-phase primary lines be classified as 100 percent demand related. The primary laterals are to be split between customer-related and demand-related using the zero-intercept method.

Using the data in Appendix A, the primary circuit length is split between three-phase, two-phase, and one-phase, as shown below.

Type of Circuit	Circuit Length in km	Percent of Total
Three Phase	1,101.3	51.05%
Two Phase	102.6	4.75
One Phase	953.5	44.20
	2,157.4	100.00%

The split between primary and secondary circuit length is as follows:

Type of Circuit	Circuit Length in km	Percent of Total
Primary	2,157.4	75.95%
Secondary	683.2	24.05
	2,840.6	100.00%

Current practice calls for the use of 1/0 AASC conductor for both three-phase main feeders and laterals. On that basis, the total cost for three-phase main feeders, including materials, labor, engineering, project management, load rights, environment, operations cost, overheads and LDC, is $52,000 per km. The median cost of single-phase laterals is $43,500 per km. A research of the conductor sizes used by Hydro for primary lines shows that a substantial percentage of three-phase lines currently exceed 1/0 AASC and have a unit cost that is more than double the unit cost of the 1/0 AASC conductor. This leads to the conclusion that the cost per km difference for existing three-phase feeders is greater relative to single-phase laterals, as compared to the data for new lines using only 1/0 AASC.

In order to arrive at a figure for primary conductors included in three-phase lines, it is necessary to calculate the three-phase conductor length by conductor size. In that analysis, it is assumed that all conductors larger than 1/0 AASC are used only on three-phase lines. The additional amount necessary to arrive at the total length of three-phase line is assumed to be 1/0 AASC. The total length of three-phase line is calculated as the product of three-phase circuit length and number of primary conductors. It is further assumed that the neutral conductor is a reduced size on existing lines, and, where possible, a common neutral is used for both primary and secondary lines. Based on the foregoing, 67.5 percent of primary conductor investment is assumed to be three phase and classified as 100 percent demand related. Details of that calculation are provided in Appendix C. The remainder is split between demand-related and customer-related cost using the zero-intercept method, *i.e.*, 78.3 percent demand related and 21.7 percent customer related, using data from the generic hearing.

The split between primary and secondary conductor investment using the split in length from the foregoing text table, conductor unit cost data for the Hydro Rural Central Area, and adjusting for the assignment of common-neutral conductor, is 69.9 percent to primary conductor and 30.1 percent to secondary conductor. See Appendix C for details of that calculation.

Pole Cost Classification

The split of pole investment between primary and secondary lines is based on the circuit-length data in Appendix A and the assumption that 25 percent of secondary line provides a common neutral conductor and, therefore, occupies the same poles on the primary line. On that basis, the split of pole investment based on the previously provided split in primary and secondary circuit lengths is 37.1 percent to demand-related three-phase lines, 40.5 percent to single and two-phase and neutral primary lines, and 22.4 percent to secondary lines. See Appendix D for details of that calculation.

Pole investment in single-phase and two-phase and neutral lines, and in secondary lines is classified to demand related and customer related using the zero-intercept method.

The zero-intercept approach used by Newfoundland Hydro, in the past, split pole investment between demand-related and customer-related cost on the basis of pole length. While that approach is commonly used, Mr. Baker's concern that length is dictated by ground clearance requirements is well taken. An analysis shows that most poles on the Newfoundland Hydro are 35 feet, unless greater height is required to accommodate multiple circuits, line transformers, street lights, etc. Accordingly, we obtained installed-cost data for 10.7 meter distribution poles for classes 1 through 5. Pole classes differ in terms of the ultimate resisting moment, which in turn is a function of the diameter of the pole at the ground line. A regression analysis prepared on the basis of ground line diameter is provided on the following page. The analysis shows that the zero-intercept cost of 10.7 meter poles is $166.45. That figure is 33.63 percent of the average cost of a ruling size class 5 pole. Thus, 33.63 percent of pole investment will be allocated to the customer-cost component and the remainder to demand-related cost.

__Distribution Transformer Classification__

Mr. Baker expressed a reservation regarding the use of the zero intercept because of a perceived difference in transformer weight by voltage classification, namely, 4.16, 12.5 and 25 kV. The data provided in Appendix B shows that transformer dimensions and weight are the same for all single-phase transformers up to 18 kV and three-phase transformers up to 25 kV. Note that the 25-kV phase-to-ground voltage is 14.4 kV, so that the single-phase transformers used on a 25 kV circuit fall within the 18 kV category. In view of this, no alternative has been considered to the zero-intercept method used in the classification of distribution transformers.

__Services and Meters__

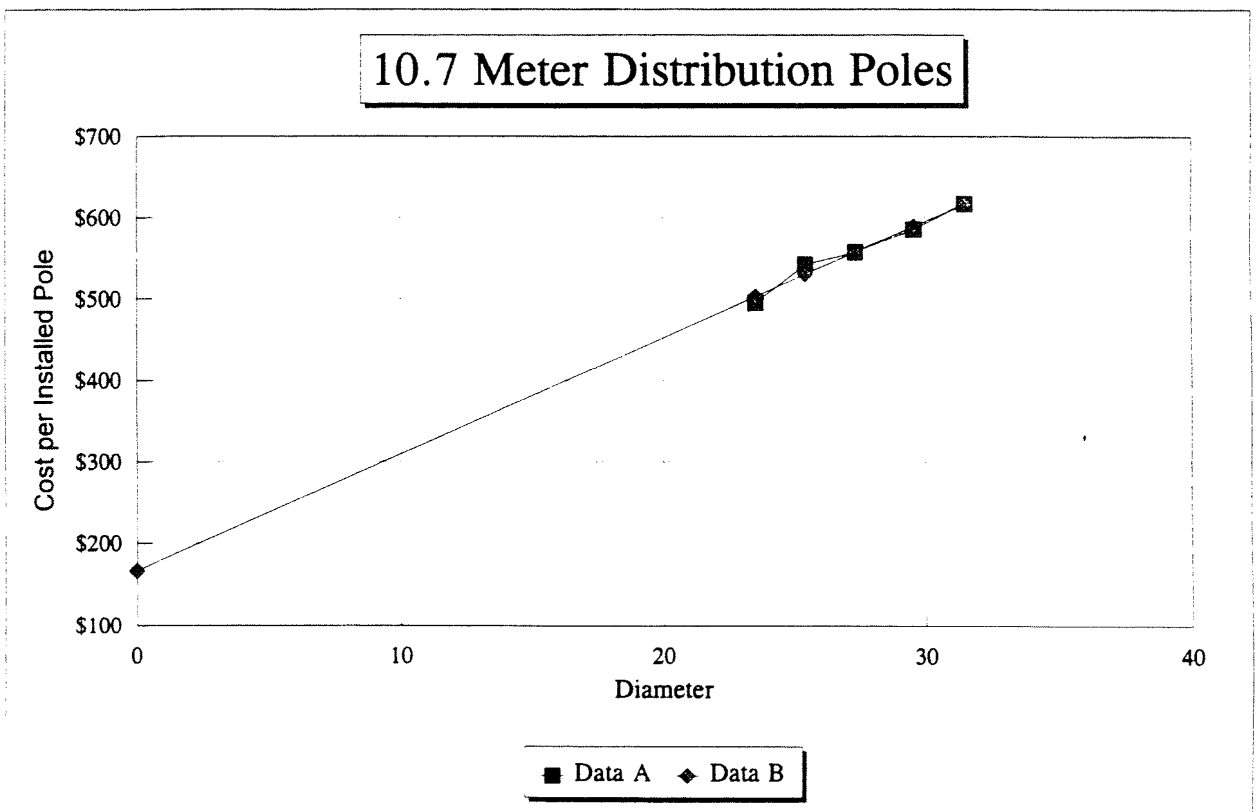
No change in the existing approach of classifying 100 percent of the cost of services and meters is proposed at this time.

POLE INVESTMENT REGRESSION ANALYSIS

Class	Cost / Pole	Installed Cost / Pole	Circumference	Diameter	Calculated Installed Cost / Pole
		$325.0		3.1415927	
1	$292.00	$617.00	99.00	31.513	$616.5
2	$260.00	$585.00	93.00	29.603	$589.2
3	$232.00	$557.00	86.00	27.375	$557.4
4	$217.00	$542.00	80.00	25.465	$530.1
5	$170.00	$495.00	74.00	23.555	$502.8
0				0.000	$166.4

Regression Output:

Constant	**$166.446**
Std Err of Y Est	8.580
R Squared	0.9738004
No. of Observations	5
Degrees of Freedom	3
X Coefficient(s)	$14.281
Std Err of Coef.	1.352



IV. CONCLUSION AND RECOMMENDATIONS

A. Conclusions

The following paragraphs describe the conclusions reached regarding the classification between customer and demand related cost based on our literature review and survey of current practices.

Academic Research

Academic research as well as technical papers by practitioners, with few exceptions, favor the use of a customer component. Use of the zero intercept method is favored since it avoids the classification of small components of total cost to demand that is inherent in the minimum plant method. Data availability may be an issue and limit the options available to the analyst. Criticism of the calculation of customer components in the text by Bonbright does not appear justified based upon the source relied upon.[18]

U.S. Utility Practice

A review of U.S. practice based upon regulatory commission orders shows that most utilities classify distribution between demand and customer related cost.

Canadian Utility Practice

Virtually all Canadian utilities classify 100 percent of distribution substation cost as demand related. Two utilities classify 100 percent of three-phase primary lines as demand related. Single-phase primary laterals are classified to demand-related and customer-related cost based on consultant's recommendations or the use of minimum plant or zero-intercept methods. The range of classification of primary lines to the customer component is 18.4 to 100 percent,

[18] See text pages 6 and 7.

with an average of 50.3 percent. Primary line poles, when separately classified, range from 63.5 to 100 percent customer related.

Line transformer classification to the customer component ranges from zero to 61 percent, with an average of 31.1 percent. Secondary line classification to the customer component ranges from 18.6 to 100 percent, with an average of 60.3 percent. Secondary line poles, when separately classified, range from 33 to 100 percent classified as customer related, with an average of 74.3 percent. All Canadian utilities classify services and meters 100 percent to customer-related cost.

B. Recommendations

The following paragraphs summarize our recommendations with the classification of distribution costs between demand-related and customer-related components by Newfoundland Hydro.

Distribution Substation Costs

The present practice is to classify distributors' substation costs 100 percent to demand. The wisdom of that approach is confirmed by our research and no change is recommended.

Primary Line Cost

Primary line cost consists of conductor and pole cost. Based upon the apparent trend in Canadian practice and giving recognition to cost behavior, it is proposed that all three-phase primary lines be classified 100 percent to demand.

It is recommended that the remaining primary conductor investment be split between demand-related and customer-related cost using the same zero-intercept methodology used in the past.

With respect to the investment in poles, the use of the zero-intercept method in a fashion that recognizes pole diameter at the ground line rather than length, as described in Chapter III of this report, is recommended.

No change in the classification of secondary conductor is proposed. The current approach is based upon use of the zero-intercept method.

It is recommended that the classification of secondary-distribution pole investment utilize the same approach recommended above for primary-line pole investment.

Distribution Transformers

The present practice of Canadian utilities supports use of the zero-intercept method which has been used in the past by Newfoundland Hydro to classify cost between demand related and customer related. As discussed in Chapter III of this report, Mr. Baker's concern about the influence of transformer weight difference by voltage class appears to be unfounded. Continued use of the zero-intercept method is recommended.

Secondary Line Cost

It is recommended that the zero-intercept method continue to be used to classify secondary conductor cost between demand and customer related. With respect to secondary poles, it is recommended that the zero-intercept methodology be revised to conform to the approach using pole-ground-line diameter in the regression analysis, as discussed in Chapter III of this report.

Services and Meters

It is recommended that 100 percent of the cost of services and meters continue to be classified to the customer component. This approach is consistent with Canadian practice elsewhere.

APPENDIX A

PRIMARY AND SECONDARY CIRCUIT LENGTH

Newfoundland & Labrador Hydro

4.16kV Feeders		Primary (km)			Secondary (km)
Feeder	Area	3-phase	2-phase	1-phase	
547-11	Labrador	14.8	0.0	1.6	3.3
262-1	Western	4.9	0.4	4.3	5.5
142-1	Labrador	4.5	0.0	9.9	8.0
230-1	Labrador	4.1	0.1	3.8	2.3
HU-2	Lab City	3.9	0.0	0.1	N/A
QZ-2	Lab City	3.4	0.0	0.5	N/A
240-1	Central	3.3	0.2	1.3	3.7
QZ-4	Lab City	3.3	0.7	1.6	N/A
265-1	Northern	3.0	0.0	3.0	3.7
432-1	Labrador	3.0	0.8	2.6	4.1
568-3	Southern	3.0	0.8	0.2	4.9
HU-3	Lab City	2.7	0.2	0.5	N/A
QZ-5	Lab City	2.6	0.0	0.0	N/A
420-8	Labrador	2.6	0.0	0.7	N/A
QZ-6	Lab City	2.6	1.2	0.9	N/A
HU-1	Lab City	2.5	0.5	0.2	N/A
BA-5	Lab City	2.5	0.3	0.5	N/A
HU-4	Lab City	2.4	0.0	0.4	N/A
320-2	Western	2.1	2.7	0.3	7.1
588-2	Southern	2.0	0.0	0.1	0.1
651-3	Central	2.0	0.5	2.8	6.2
280-1	Labrador	2.0	0.4	4.2	5.6
BA-4	Lab City	2.0	0.6	0.0	N/A
QZ-3	Lab City	1.9	0.3	0.8	N/A
766-1	Central	1.6	0.0	0.0	1.0
180-3	Central	1.5	3.9	0.5	6.1
568-2	Southern	1.5	1.2	1.1	5.2
222-2	Central	1.5	0.3	0.3	2.1
420-7	Labrador	1.3	0.0	0.1	N/A
469-1	Labrador	1.3	0.0	1.7	1.8
588-1	Southern	1.3	1.1	2.3	5.5
547-7	Labrador	1.3	0.0	0.0	0.0
BA-1	Lab City	1.3	0.2	0.1	N/A
361-1	Central	1.2	0.3	9.1	5.8
BA-3	Lab City	1.2	0.0	0.0	N/A
527-1	Labrador	1.0	0.2	2.1	2.2
BA-2	Lab City	1.0	0.1	0.5	N/A
568-4	Southern	1.0	0.1	0.2	1.4
HL-2	Lab City	0.9	0.0	1.3	N/A
420-13	Labrador	0.9	0.0	0.0	N/A
744-1	Northern	0.9	0.0	1.7	1.1
116-1	Labrador	0.8	0.0	6.1	2.3
360-1	Central	0.7	4.8	5.6	5.1
QZ-1	Lab City	0.5	0.6	0.8	N/A
191-1	Southern	0.4	0.0	0.4	1.2
837-1	Northern	0.3	0.3	1.1	0.4
180-2	Central	0.3	1.8	0.1	2.7
HL-1	Lab City	0.3	0.7	1.7	N/A
130-1	Northern	0.2	0.3	3.5	2.7
320-3	Western	0.1	0.4	0.0	0.4
700-4	Northern	0.0	0.0	0.0	0.0
245-1	Southern	0.0	0.2	5.4	0.9
260-2	Central	0.0	0.0	3.2	1.3
272-1	Labrador	0.0	0.7	1.8	1.1
199-1	Southern	0.0	0.1	0.9	0.6
		105.0	**27.1**	**91.9**	**105.4**

Newfoundland & Labrador Hydro

12.5kV Feeders		Primary (km)			Secondary (km)
Feeder	Area	3-phase	2-phase	1-phase	
129-1	Western	30.3	0.0	23.4	8.5
129-2	Western	12.2	0.0	5.0	8.5
129-3	Western	14.0	0.0	4.1	4.7
130-2	Northern	0.0	0.0	24.3	0.6
150-1	Western	4.4	0.0	19.5	12.2
159-1	Western	2.0	0.0	26.8	8.8
175-4	Western	21.1	0.0	3.7	7.0
175-5	Western	13.2	0.0	1.1	1.0
175-6	Western	21.3	0.5	22.2	18.2
175-7	Western	0.0	0.0	0.7	0.1
180-4	Central	9.1	2.6	1.9	8.4
180-5	Central	14.1	0.4	13.3	16.4
180-6	Central	18.3	4.6	17.7	14.2
189-1	Northern	2.5	0.0	4.2	3.4
211-1	Central	3.2	6.4	3.5	6.0
222-3	Central	0.0	0.6	8.7	0.1
265-2	Northern	0.0	0.0	9.8	1.2
268-1	Central	0.2	0.0	0.8	1.0
282-1	Western	8.0	1.8	26.2	14.8
282-2	Western	10.5	0.6	6.1	11.2
299-1	Central	3.7	1.1	3.4	7.0
299-1	Western	1.9	0.0	9.5	9.6
299-2	Central	12.7	5.3	7.2	7.7
300-1	Northern	0.2	0.3	9.1	4.7
320-1	Western	20.7	0.4	2.5	9.4
320-3	Western	2.6	0.0	0.7	1.4
320-4	Western	8.0	0.0	21.3	4.1
336-2	Central	0.0	4.7	4.2	4.6
337-1	Central	0.1	0.2	1.0	1.7
354-1	Central	0.2	0.4	1.1	1.3
356-4	Central	12.2	2.3	2.8	11.0
356-6	Central	10.9	0.3	4.2	3.7
356-7	Central	3.2	1.1	2.9	8.3
360-2	Central	0.0	7.7	3.7	2.7
398-1	Central	0.3	0.6	9.0	4.6
399-1	Western	12.6	0.0	2.7	15.4
399-2	Western	16.0	0.0	3.8	3.9
401-2	Central	0.0	0.0	6.3	3.0
420-11	Labrador	3.6	0.0	0.2	N/A
420-12	Labrador	7.1	0.1	2.6	N/A
420-3	Labrador	1.3	0.0	1.7	N/A
420-9	Labrador	0.6	0.0	0.9	N/A
487-1	Northern	18.2	0.0	21.0	8.7
487-2	Northern	13.2	0.4	6.6	12.5
635-1	Western	3.0	0.0	26.0	9.2
635-3	Western	29.5	1.1	34.2	22.6
638-1	Central	4.3	0.0	4.8	6.4
651-2	Central	0.0	4.7	3.8	3.0
651-4	Central	23.9	4.4	9.0	10.4
651-5	Central	11.1	1.4	11.1	12.8
671-1	Western	2.3	0.0	0.3	0.9
700-2	Northern	3.2	0.0	3.4	8.9
700-3	Northern	11.9	0.0	20.5	17.4
700-5	Northern	0.0	0.0	14.6	3.7
700-6	Northern	21.7	2.2	61.3	24.7
700-7	Northern	25.0	0.0	18.0	7.7
791-1	Central	13.0	0.0	0.1	0.0
		482.3	**56.1**	**558.7**	**399.2**

Newfoundland & Labrador Hydro

25kV Feeders		**Primary (km)**			**Secondary (km)**
Feeder	**Area**	**3-phase**	**2-phase**	**1-phase**	
487-3	Northern	0.0	0.0	44.9	5.4
262-2	Western	0.0	0.0	36.4	2.4
444-1	Central	41.0	0.4	36.2	13.7
336-1	Central	20.0	0.5	30.0	12.2
651-1	Central	30.3	0.0	28.8	8.3
356-1	Central	52.5	1.6	27.6	14.0
370-1	Central	34.6	0.0	27.0	33.3
222-1	Central	34.0	14.0	12.2	10.6
547-4	Labrador	1.3	0.0	7.5	9.9
700-1	Northern	48.9	0.0	7.1	2.6
547-7	Labrador	43.5	2.6	6.2	11.2
260-1	Central	17.6	0.0	5.9	0.0
356-3	Central	15.6	0.0	5.7	2.4
547-3	Labrador	2.3	0.0	3.4	5.8
547-10	Labrador	10.6	0.1	3.0	11.7
547-6	Labrador	1.9	0.0	2.8	5.8
401-1	Central	21.9	0.0	2.6	4.4
547-5	Labrador	2.9	0.0	2.4	7.5
370-2	Central	16.4	0.0	2.2	0.2
180-1	Central	29.5	0.0	2.0	0.2
356-2	Central	0.0	0.0	1.9	0.0
547-11	Labrador	14.8	0.0	1.6	3.3
547-2	Labrador	5.0	0.0	1.5	5.8
547-1	Labrador	6.3	0.0	1.4	0.2
651-7	Central	15.5	0.0	1.2	2.5
568-1	Southern	25.2	0.1	0.6	2.1
356-8	Central	2.0	0.2	0.6	3.0
547-15	Labrador	4.2	0.0	0.0	0.0
547-17	Labrador	3.9	0.0	0.0	0.0
547-16	Labrador	12.3	0.0	0.0	0.0
		514.0	**19.4**	**302.9**	**178.6**

APPENDIX B

TRANSFORMER WEIGHT BY VOLTAGE CLASS

OUTLINE DIMENSIONS - TYPE O.N.A.N. UP TO 18 kV (125 kV BIL) DIRECT TO POLE MOUNTING BUILT TO C.S.A. C2

SINGLE PHASE — STANDARD LOSSES AND IMPEDANCE

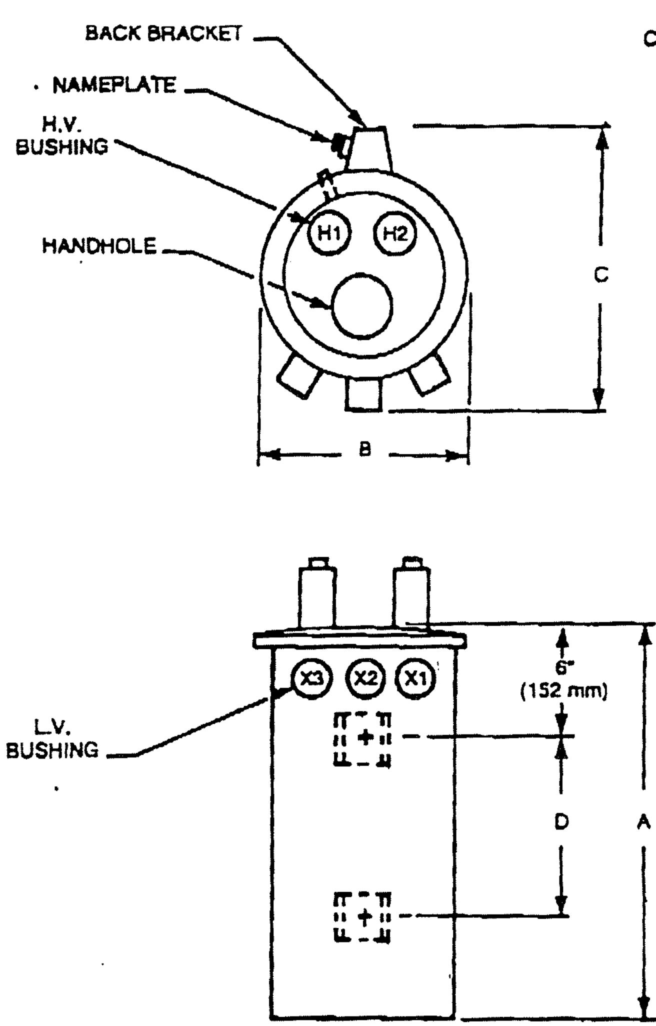


Fig. 1

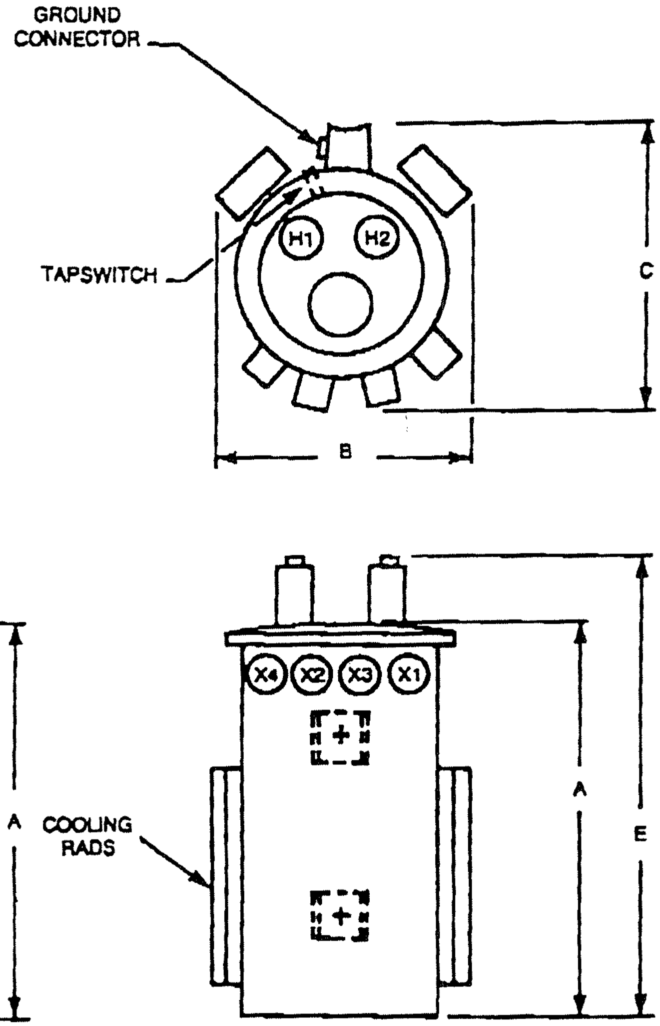


Fig. 2

(HANGER IRONS AND ADAPTER PLATES AVAILABLE UPON REQUEST)

NO.	K.V.A.	FIG.	A		B		C		D		E		QTY. OF OIL		APPROX. WT.	
			Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Gals	litres	Lbs.	kg
1	10	1	22½	572	19	485	21½	546	14½	370	34	863	7	31.8	260	118
2	15	1	22½	572	19	485	21½	546	14½	370	34	863	7	31.8	274	124
3	25	1	26½	673	21	535	23½	597	14½	370	38	965	11.7	53.1	390	177
4	37	1	32½	826	21	535	23½	597	14½	370	44	1118	15	68.1	490	222
5	50	1	35½	902	23	585	25½	648	21½	550	47	1194	22	100.0	645	293
6	75	2	40½	1029	25	635	27½	699	21½	550	52	1321	32	145.3	856	389
7	100	2	37½	953	29	735	30½	775	21½	550	49	1245	31.5	143.0	980	445
8	167	2	37½	953	46½	1180	32	813	28½	730	49	1245	41	186.1	1375	625

OUTLINE DIMENSIONS - TYPE O.N.A.N. UP TO 25 kV (150 kV BIL) DIRECT TO POLE AND PLATFORM MOUNTING TO CSA C2

THREE PHASE — STANDARD LOSSES AND IMPEDANCE

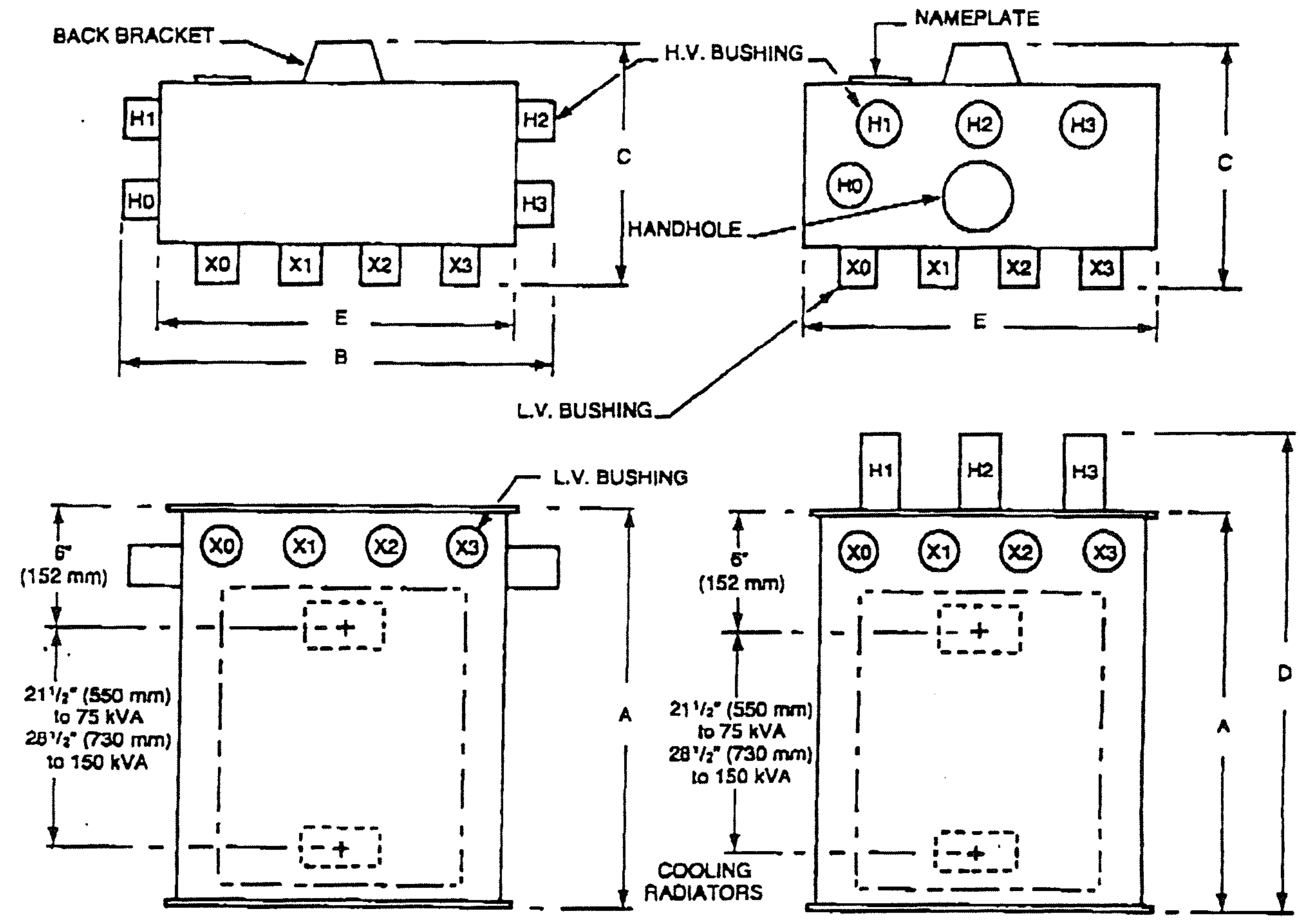


Fig. 1

Fig. 2

(HANGER IRONS AND ADAPTER PLATES AVAILABLE UPON REQUEST)

NOTES: 1) For 15 kV reduce dim. 'D' by 6" (152 mm)
2) Back brackets supplied to 150 kVA only
3) Fig 1 applies up to 225 kVA 5 - 8.66 kV class
4) Fig 2 applies up to 225 kVA above 8.66 kV class and all 300 - 500 kVA.

NO.	K.V.A.	A		B		C		D		E		QTY. OF OIL		APPROX. WT.	
		Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Gal	litres	Lbs.	kg
1	15	33	838	41	1041	24	610	45	1143	33	838	28	106	600	272
2	30	33	838	41	1041	25	635	45	1143	33	838	31	117	750	340
3	45	33	838	44	1117	29	737	45	1143	36	914	39	148	915	415
4	75	33	838	51	1295	32	813	45	1143	43	1092	59	223	1290	585
5	112	40	1016	54	1372	34	864	52	1321	46	1168	78	295	1820	825
6	150	40	1016	55	1397	38	965	52	1321	47	1194	89	337	1930	875
7	225	40	1016	61	1549	40	1016	52	1321	53	1346	106	401	2930	1329
8	300	40	1016	62	1575	43	1092	52	1321	54	1372	112	424	3070	1393
9	500	48	1219	74	1880	45	1143	60	1524	66	1676	167	632	4815	2184

APPENDIX C

CALCULATION OF SPLIT OF CONDUCTOR COST BETWEEN PRIMARY AND SECONDARY

CALCULATION OF PRIMARY AND SECONDARY CONDUCTOR COST

Total Cost of Conductor

The first step in the split of primary and secondary conductor cost is to calculate the total cost of primary conductor and secondary conductor using unit costs developed for Hydro's Central Area. The calculation of total primary conductor cost of $7,113,121 is provided in Table C-1, using conductor length data by conductor size, and corresponding unit price data.

The calculation of total secondary cost is based upon a secondary circuit length of 683.2 km shown on page 23 of the text of this report, multiplied by three conductors per circuit, and by an average unit cost per meter. The resulting figure is $3,253,330. The unit cost of $1.5873 per meter for secondary conductor was developed using the data shown in Table C-2.

Impact of Common Neutral

The secondary line neutral conductor is used as a common neutral for both primary and secondary lines whenever the primary and secondary lines occupy the same poles. It is conservatively estimated that 25 percent of the secondary circuit occupies the same poles as primary circuit. The length of this common neutral is 25 percent of the total secondary circuit length of 683.2 km or 170.8 km. Cost of that common neutral is estimated as the product of 170.8 km $\times$ 1,000 $\times$ $1.5873 or $271,110.84. One half of that amount, or $135,555, is reassigned to primary conductor cost.

The total primary conductor cost, adjusted for the impact of using a common neutral, is $7,248,676.16, calculated as $7,113,121 plus $135,555. The total adjusted secondary conductor cost is $3,253,330 less $135,555, or $3,117,775.

TABLE C - 1

Calculation of Total Primary Conductor Cost

Newfoundland Labrador Hydro

Conductor Size	Length of Conductor - meter	Unit Costs - $/meter	Conductor Cost
1/0aasc	3,017,058	0.77	$2,323,135
2acsr	1,451,711	0.65	943,612
4/0aasc	1,402,691	1.53	2,146,117
4cu	287,352	1.10	316,087
2/0aasc	232,506	1.08	251,106
477al	89,026	3.12	277,761
636al	63,991	4.86	310,996
266.8acsr	92,526	3.32	307,186
2cu	126,802	1.87	237,120
	6,763,663		$7,113,121

TABLE C - 2

Average Cost of Secondary Line -
Based on Hydro Rural Central Area

Newfoundland Labrador Hydro

Conductor Size	Conductor - meter	Unit Costs - $/meter	Conductor Cost
#2 triplex	4,187	1.73	$7,244
#2 cu.	10,644	3.06	32,571
#4 cu.	276,054	2.07	571,432
#6 cu.	39,518	1.53	60,463
#2 al.	101,773	1.01	102,791
4/0 al.	13,082	2.25	29,435
1/0 al.	70,448	1.32	92,991
2/0 al.	141,145	1.11	156,671
#4 triplex	27,670	1.26	34,864
#6 duplex	6,838	0.89	6,086
1/0 cu.	2,117	2.94	6,224
	693,476	1.5873	$1,100,770

Cost of Three-Phase Primary

The calculation of the cost of the three-phase primary of $5,275,765 is provided in Table C-3. The total length of the three-phase circuit is 1,101.3 km as shown on page 23 of the text. Cost includes both the phase conductors and a reduced-size neutral. Average cost of the neutral conductor shown on that table is $0.8052 per meter. The three-phase primary is 51.05 percent of total primary as shown in the text table on page 23. Therefore, the length of common neutral in the three-phase segment is 170.8 km × 0.5105, or 87.193 km. The impact of the common neutral on the three-phase conductor investment is 170.8 × 1,000 × (0.8052 - 0.7937), or $1,964. The adjusted three-phase conductor cost is $5,275,765 - 1,964, or $5,273,800. The figure of $0.7937 is the apportioned cost of the secondary line common neutral or one half of the aforementioned unit cost of $1.5873.

Cost Ratios

The three-phase primary conductor investment, which is to be classified as 100 percent demand related, is 72.76 percent of total primary conductor cost, *i.e.*, $5,273,800/7,248,676.16. The remaining primary conductor investment is 27.24 percent of the total primary conductor investment. That percentage of primary conductor cost plus all secondary conductor cost is to be classified using the zero-intercept approach.

The split of conductor investment between primary and secondary is $7,248,676/ (7,248,676.16 + 3,117,775.08), or 69.9 percent to primary and the remainder, 30.1 percent, to secondary.

TABLE C-3

Calculation of Three Phase Primary Line Conductor Cost

Newfoundland Labrador Hydro

Conductor Size		Length of Conductor - meter		Unit Costs - $/meter		Conductor Cost		
Phase	Neutral	Phase	Neutral	Phase	Neutral	Phase	Neutral	Total
1/0aasc	1/0aasc	1,423,160	474,387	0.77	0.77	1,095,833	365,278	1,461,111
4/0aasc	1/0aasc	1,402,691	467,564	1.53	0.77	2,146,117	360,024	2,506,141
2/0aasc	1/0aasc	232,506	77,502	1.08	0.77	251,106	59,677	310,783
477al	4/0aasc	89,026	29,675	3.12	1.53	277,761	45,403	323,164
636al	4/0aasc	63,991	21,330	4.86	1.53	310,996	32,635	343,631
266.8acsr	1/0aasc	92,526	30,842	3.32	0.77	307,186	23,748	330,935
		3,303,900	1,101,300			4,388,999	886,765	5,275,765

APPENDIX D

Calculation of Split of Pole Investment Between Primary and Secondary

CALCULATION OF PRIMARY AND SECONDARY POLE COST

The length of secondary line that is assumed to occupy the same pole line as primary line is 25 percent of the total length of secondary or 170.8 km (683.2 × 0.25). If the poles in that common section are to be allocated equally to primary and secondary, the adjusted length of primary pole line is 2,157.5 km - ½(170.8), or 2,072 km. Adjusted secondary length is 683.2 - ½(170.8), or 597.8 km. Total adjusted length is 2,669.8 km.

Pole line investment assigned to three-phase primary and classified 100 percent to demand = $\frac{1{,}101.3}{2{,}669.8}$ or 41.2 percent

Pole line investment assigned to other primary lines = $\frac{2{,}072-1{,}101.3}{2{,}669.8}$ or 36.4 percent

Pole line investment assigned to secondary lines = $\frac{597.8}{2{,}669.8}$ or 22.4 percent

(R)

NP-123

STUDY OF DISTRIBUTION SYSTEM

COST CLASSIFICATION

Prepared For

NEWFOUNDLAND AND LABRADOR HYDRO

FOSTER
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Prepared by

FOSTER ASSOCIATES, INC.
Washington, D.C.

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TABLE OF CONTENTS

I. INTRODUCTION

A. Purpose and Scope

The purpose of this report is to explore the extent to which distribution costs should be classified as customer related with the remainder classified as demand related. The scope is limited to the requirements for an embedded-cost-of-service analysis and, therefore, may not be appropriate for a marginal or long-run incremental cost analysis.

B. Present Conditions

The requirement for this study arose from Item No. 19 of the Public Utilities Board recommendations in their report as an outcome of the 1992 Generic Hearing. Item 19 states

> [t]hat Hydro's proposed classification of distribution cost be accepted for interim use and that Hydro prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral.

It is presumed that Mr. George Baker's pre-filed testimony, the Company's evidence, and the transcript of the cross-examination of Dr. Robert H. Sarikas and Mr. Richard A. Bellin on this subject forms the basis for that recommendation by the Board.

Mr. Baker in his pre-filed testimony, in response to a question regarding distribution-cost classification, states that

> [s]ome distribution costs correlate with the number of customers served. To reflect this, it is normal to classify service and meters entirely as customer cost. In addition, poles, wire and sometimes distribution transformers are classified partly as customer cost. All other distribution plant, if not specifically assigned, is normally classified to demand.

In response to how such costs should be classified between demand and customer, Mr. Baker further stated that

> [a]mong recognized methods, the main alternatives are the zero intercept and minimum system methods. The zero intercept method is inaccurate by reason of the fact that it only classifies the marginal cost of demand as demand cost and classifies all other cost as customer cost. The minimum system method is even worse; it only classifies a part of the marginal cost of demand to demand. For this reason, the proportion of customer cost is usually overstated where recognized analytical approaches are used, typically varying between about 45% and 70%. For such reasons some utilities prefer to split costs on a judgmental basis.

In commenting on Hydro's distribution transformer analysis, Mr. Baker agreed that the result obtained by Hydro using the zero-intercept approach, a customer component of 23.5 percent of plant cost was realistic; however, he expressed reservation about the methodology. He believed that the weight and therefore the cost of the transformer is derived from the voltage class and is therefore a consequence of demand. He ultimately recommended an analysis that classified all transformers to demand.

With respect to pole investment, Mr. Baker concluded that Hydro's zero-intercept approach for poles understated the customer-cost percentage for that item. His proposed analysis would classify all lines between the substation and load center as demand related. The customer component would be based on the ratio of the per-mile cost of a line suitable for zero demand conditions to the current cost per mile of existing lines not included in the portion of line between substations and the load center.

II. INDUSTRY PRACTICE

A. General

This chapter of the report describes a research of the literature with respect to distribution system cost classification and a review of Canadian electric utility practice in this regard.

B. Review of Literature

The review of literature encompasses the few textbooks and technical papers dealing with the issue of distribution-system cost classification.

The text by Davidson states that

> [c]ustomer or consumer costs will include (a) that part of the total cost of the distribution network that varies with the number of customers and is not attributable to variation in the maximum rate of consumption; (b) the current direct costs incurred when an additional customer desires service, such as metering expenses, bookkeeping and collection expenses, service wiring, etc.; and (c) the cost of installation and connection incurred before the beginning of service to the new customer (though possibly amortized only in the course of time). Customer costs will vary with the number of customers, given the total kilowatt hours sold a year and the maximum rate of consumption in kilowatts. Customer costs represent the marginal costs of adding another customer to the utility system.[1]

Davidson amplifies this later in his text when he states that

> [c]ustomer costs are those that vary with the number of customers and represent the marginal cost of adding another customer to the utility system. This cost element can be recovered by having a fixed charge on each customer—a fixed monthly customer charge, payable whether or not the consumer uses any electricity during the month as long as he is connected to the utility system. Installation and connection costs would be charged to the utility system. Customer

[1] Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity*. (Baltimore: The Johns Hopkins Press, 1955), pg. 62.

costs would not be the same for all customers of a utility because the investment in meters, for example, varies according to the size of the customer's expected maximum load; also the cost of reading meters would vary according to customer density.[2]

The well-known text by Caywood states that customer cost

> . . . varies with number of customers served and includes investment charges and expenses relative to a portion of the general distribution system, service drop or other local connection facilities, metering equipment, meter reading, billing, and accounting.[3]

Caywood points out that customer cost includes all cost of service, meters, customer accounting and collecting expenses, and a portion of distribution lines, line transformers, general plant, sales promotion expenses, and administration and general expenses.[4]

He also ascribes a relationship between customer and area costs:

> The cost of adding loads is less than the accumulated average, assuming a constant price level; the difference or so-called residual cost can be labeled a "customer" or "area coverage" cost. Local facility cost may be partly independent of and partly dependent upon a customer's load. The independent part can be classed a customer cost, while the dependent part can be treated on a kilowatt basis with no diversity.[5]

The text on costing and pricing published by the American Gas Association notes that

> The closer a plant item (*e.g.*, a meter and service line) is located to a customer, the more that particular item is related to the specific requirement of that customer. Thus, the customer component of distribution costs reflects the

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[2] Ibid., pg. 181.

[3] Russell E. Caywood, *Electric Utility Rate Economics*. (New York: McGraw Hill, 1956), pg. 26.

[4] Ibid., pg. 149.

[5] Ibid., pg. 172.

theoretical distribution system that would be needed to serve customers at nominal or minimum load conditions.[6]

Customer cost are defined as "invariant with respect to consumption. They are costs incurred to serve a customer even if the customer does not use the service at all."[7]That reference notes that customer costs include local connection facilities, metering, including billing and accounting, and a portion of the distribution system. It is also acknowledged that these costs are lower for a residential customer than for an industrial customer who may have an expensive transformer and switching equipment devoted exclusively to its use.[8]

Bonbright notes that the controversial aspect of customer costs is the inclusion of a substantial fraction of the annual maintenance and capital costs of the low voltage distribution system, equal to the estimated annual costs of a hypothetical system of minimum capacity. He notes that these customer cost are defended on the ground that, since they vary directly with the area of the system (or else with the lengths of the distribution lines), they therefore vary directly with the number of customers. He also describes the zero-intercept method. He then goes on to say that

> [w]hat this last-named cost imputation overlooks, of course, if the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.
>
> While, for the reasons just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer

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[6] AGA Rate Committee, *Gas Rate Fundamentals*, 4th Ed. (Arlington: American Gas Association, 1987), pg. 136.

[7] James C. Bonbright, *et al.*, *Principles of Public Utility Rates*, 2nd Ed. (Arlington: Public Utilities Reports, Inc., 1988), pg. 401.

[8] Ibid.

ground. For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the **remaining** cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[9]

Comment

A review of the referenced paper by Lessels provides cause to believe that Bonbright, *et al.*'s confidence in its relevance may be misplaced.[10] Mr. Lessels, an employee of the U.S. Rural Electrification Administration (REA) limited his analysis to electric distribution borrowers of that institution. The REA, which provides low-cost loans to cooperatives for the purpose of extending electric service in rural areas had essentially accomplished its objective of providing service to all farms by the mid-1950s. Mr. Lessel's database covers the period from 1971 through 1978. In the period starting in the mid-1950s, the number of farms began a decline (average size of the farm increased). Many of the farmhouses, no longer occupied by farm families, however, continued to be used for residential purposes. Customer growth of the REAs in the 1970s was primarily in the areas adjacent to the towns and cities. Since these customers were closely spaced as compared to the original farms in rural areas, there is little wonder that investment per customer, as well as expense per customer, declined, leading to Mr. Lessel's conclusion that the costs were not correlated with the change in year-round farm and residential

[9] Ibid., pg. 491-2.

[10] David J. Lessels, "The Economics of Electric Distribution System Costs and Investments," *Public Utilities Fortnightly*. Dec. 4, 1980, pg. 37-40.

customers. This issue will be discussed at greater length in Chapter III of this report. It is interesting to note that Bonbright goes on to state that "[i]n actual practice the vast majorities of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."[11]

A paper by Sterzinger claimed that the use of a minimum system resulted in an overallocation of costs to low-use residential customers because it is possible that such customers are capable of supply from a minimum system.[12] However, their demand, while less than average, nevertheless results in an additional allocation of cost to that customer class.

__Comment__

The argument presented by Sterzinger would presumably favor the zero-intercept method over the minimum-plant method.

A recent, and to some degree authoritative, text dealing with customer costs in general has been published by the National Association of Regulatory Utility Commissioners (NARUC). It devotes two chapters to this topic.[13] The tables in Chapter 6 thereof call for all services, meters, and property on customers' premises to be classified entirely as customer related. A portion of distribution and land rights, structures and improvements, poles, overhead and underground conductors and conduits, and line transformers are to be classified in part as customer related. In general, related operating and maintenance expenses follow plant, except that customer account expenses, customer service and information expenses, and sales expenses are classified as customer related. The two methods used to determine the demand and customer components of distribution facilities are the "minimum size of facilities method" and the "minimum intercept cost method."

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[11] Bonbright, *et al.*, pg. 492.

[12] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," *Public Utilities Fortnightly*. July 2, 1981, pg. 30-32.

[13] Staff Subcommittee on Electricity and Economics, *Electric Utility Cost Allocation Manual*. (Washington, National Association of Regulatory Utility Commissioners, 1992), Ch. 6 and 7.

In applying the minimum size method, the installed cost of a minimum height pole is multiplied by the total number of poles to find the customer component. For overhead conductors, the cost of a two-conductor minimum size circuit-mile is multiplied by the total number of circuit miles to determine the customer component. The line transformer component is determined by multiplying the total number of transformers by the cost of a minimum size transformer. It is pointed out that the technique can be applied to services by multiplying the total number of services by the cost of a minimum-size service.[14]

The NARUC manual states that the minimum intercept method "[i]n most instances is more accurate, although the differences may be relatively small."[15] The technique recommended for poles would require historic cost data by height and class of pole, which is normally not available from the accounting systems of North American utilities.[16] Variants of the recommended approach may be feasible.

In a critique of the two approaches, the authors point out that the minimum system, but not the minimum-intercept method, may result in a portion of demand not being included in the customer component.

C. <u>Regulatory Commission Treatment of Customer-Related Cost</u>

This section describes the pronouncements of various U.S. state regulatory commissions dealing with customer cost issues that have appeared in the rate orders of electric utilities under

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[14] That approach does not take into account the fact that the larger services may be related to customer classes other than residential.

[15] Ibid., pg. 92.

[16] The recommended technique is as follows:

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by crating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

their jurisdiction.[17] In addition, a number of State Commissions have approved the use of the minimum-size method, and the zero-intercept method for gas distribution systems.

Connecticut

The Connecticut Department of Public Utility Control in its Order stated that "Distribution costs are driven by the number of customers served and the kilowatts of demand imposed by those customers." It discussed the features and methodology of the minimum-size method and the zero-intercept method, and noted that the minimum-intercept method has been recognized by the Department as an appropriate method and had been used by Connecticut Power & Light (CPL) in previous cases. CPL had requested permission to substitute the minimum-size methodology because of the Department's concern with what it regarded as deficiencies in CPL's use of zero-intercept method. In this case, the Department was critical of the minimum-plant methodology used by CPL, alleging that excessive sizes of poles, conductors, etc. were used. The Department stated that the minimum-size system should represent a theoretical system comprising minimum-size units of plant actually used and not necessarily conforming to current construction standards or practice. *Connecticut Power and Light Co.*, Docket No. 88-05-25, December 21, 1988.

In a later case, Connecticut Light and Power Co. (CLP) submitted a customer cost analysis based on both the minimum-size and zero-intercept methods. The two methods produce similar results on a totalized-plant basis. The distribution component for the minimum-size methodology was 52.9 percent, and 52.4 percent for the zero-intercept method. With respect to the two methods, the Department noted that the results for individual distribution accounts showed greater variations.

The Department stated that its concern with what it believes were deficiencies in CLP's application of the minimum-intercept methodology, combined with the fact that the minimum-size methodology requires less data, is easier to apply, is more readily understood, and is less

[17] The most generally used source is the data published by *Public Utility Reports*.

costly to perform, led it to grant CLP's request to use the minimum-size method on an interim basis.

The Department believes that the simplicity of the minimum-size methodology together with its producing results similar to the much more complex minimum-intercept methodology, warrants its continued use by CLP in future cost studies.

The Department believes that some tangible portion of the distribution system rightfully should be allocated on the basis of customers served. The issue is should the minimum system lean toward what could be characterized as the minuscule system concept or should it more closely reflect the smallest plant sizes actually used.

The Department rejected the minuscule system concept and supported a minimum system that perhaps should be leaner than that proposed by the Company. *Connecticut Light and Power Co.*, Docket No. 90-12-03, Order dated August 1, 1991.

Florida

The Commission pointed out that its policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer related. The Industrial Intervenors and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer related, using the minimum-distribution-system concept. The Commission stated that there is a fundamental flaw in this proposal in that only part of the **distribution** system is classified as customer related. None of the subtransmission and transmission system would be classified as customer related. Hence, customer served at primary voltage through dedicated substations, and customers served at higher voltage would not pay for any of this network path.

It therefore reaffirmed its original position of classifying only service drops and meters as customer related. *Gulf Power Company*, Case 891345-EI, Order No. 23573, dated October 3, 1990.

The Commission rejected the concept of a minimum distribution system, stating that reliance on such a mechanism is speculative at best. The Commission stated that the appropriate customer charge should be based upon the cost of the meter, service, drop, meter reading, and basic customer-service costs exclusive of uncollectibles. *Tampa Electric Company*, Docket No. 80011-EO(CR), Order No. 9599, dated October 17, 1980.

Maine

The Commission stated that when allocating distribution plant between demand and customer components, it is appropriate to include in customer charges the cost of a minimum system, and such will not be unfair to low-usage customer, as the customer charge is not designed to reflect each customer's minimum demand but is to cover the costs of the system design to meet minimum safety and service requirements. *Central Maine Power Co.*, Docket No. 80-66, Order dated September 11, 1985.

The following discussion relates to a judicial review by the Maine Supreme Court of an Order of the Maine Public Utilities Commission. The Court discussed a number of issues, including customer cost. The Company used the minimum-size method in its analysis and that approach was approved by the Commission. Various intervenors objected and stressed statements in Dr. Bonbright's book that such costs are unallocable. The judge pointed out that Bonbright criticized the inclusion of such costs in demand costs with equal fervor. The NARUC cost-allocation manual, which was placed in evidence, recognizes two methods of determining the customer-cost component of distribution plant: the minimum-size and minimum-intercept methods. The judge pointed out that the intervenor witness conceded on cross-examination that his proposal to classify distribution-plant costs to demand-related cost was not recognized in the NARUC manual while use of the minimum-size was. The judge concluded that the Commission, faced with the dilemma of whether to treat such cost as customer related or demand related, was entitled to exercise reasonable discretion in selecting a methodology. He stated that "adoption of the policy urged by the intervenors of classifying the costs of the minimum-distribution system to the energy (demand) charge would be equally imperfect, and Commission discretion must therefore carry the day." *Central Maine Power Co. v. Maine Public Utilities Commission, et al.*, Case 402, A.2d 153, Order dated August 6, 1979.

New York

The rulings of this Commission differ in terms of the utilities under its jurisdiction.

The Commission adopted a proposal that eliminated minimum grid costs as customer related since the hypothetical minimum grid costs were considered to be common to both the demand and customer components and, as such, not allocable between them. This was stated in response to the testimony of Mr. George Sterzinger, discussed *supra*.

The Commission further stated that "while both methods—minimum size and zero intercept—are reasonable, the zero-intercept method is generally preferable." *Central Hudson Electric & Gas Corp.*, Case 27636, Opinion 82-11, May 19, 1982.

In the case of Rochester Gas & Electric Co., the Commission upheld an allocation of electric service costs based on a system with minimal capacity. *Rochester Gas and Electric Co.*, Case 28896, Opinion No. 85-13, July 9, 1985.

The Commission, over the objections of intervenors, approved the methodology used by Niagara Mohawk Power Corp., of calculating non-demand-related distribution costs (identified as customer costs by Niagara). That methodology treats capitalization-installation costs (labor costs) as customer costs, and all other costs are demand related. The Commission suggested an alternative name such as "service" or "delivery" costs. *Niagara Mohawk Power Corp.*, Case 29327, *et al.*, Opinion 87-3, March 13, 1987.

North Carolina

The Company proposed to discontinue use of the minimum system technique and was supported in this effort by the Commissions staff. The Commission disagreed and concluded that the minimum system technique should not be discontinued at this time. It noted that the minimum system technique allocates more of the distribution plant to residential customers and less to industrial customers. It further stated that the method is conceptually sound, even if the results of such a technique are not fully reflected in the basic customer charges. *Carolina Power & Light Co.*, Docket E-2, Sub. 526, August 27, 1987.

Pennsylvania

The Commission was satisfied that an electric company classified a portion of distribution plant as customer related, allocating customer costs to classes on a customer base. It rejected a claim that any distribution plant should be classified as energy related. *Pennsylvania Public Utility Commission v. Pennsylvania Electric Co.*, Case R-822250, *et al.*, October 14, 1983.

The Commission concluded that since certain costs have no relationship to the minimum or maximum capacity required for service, it is therefore appropriate to allocate distribution-plant costs on a demand-customer basis. *Pennsylvania Public Utility Commission v. Duquesne Light Co.*, 59 PaPUC 67, R-842583, January 24, 1985.

Utah

The Commission rejected the minimum distribution system for satisfying distribution costs, since that system would result in a double allocation of these cots to low-use customers, but found that it would be reasonable, now and for the future, to classify each distribution system account as demand cost or customer cost, based upon engineering analysis. *Utah Power & Light Co.*, Case No. 79-035-12, Order dated March 7, 1983.

Wisconsin

After reviewing various proposals for the calculation of customer-related cost calling for the inclusion and exclusion of various components of the distribution system, the Commission concluded that a customer-cost determination incorporating billing expenses, cost of the meter, service line, and a portion of the distribution plant that varies with the number of customers is considered appropriate and is to be utilized in the rate design. *Madison Gas and Electric Co.*, Case 3270-UR-1, Order dated November 9, 1976.

D. Canadian Practice

Data with respect to the calculation of customer-related cost by the following Canadian electric utilities was obtained by personal contact or a review of cost-allocation studies prepared by them.

Nova Scotia Power Corporation

The approach used by Nova Scotia Power Inc. to split distribution cost between demand and customer related in its cost study submitted to the Nova Scotia Utility and Review Board, and covering the time period for the year ending December 31, 1996 relies on percentages based on construction and engineering estimates. The investment in poles and wire is split between primary and secondary distribution. All primary distribution is treated as demand related while secondary distribution is treated as customer related. In the analysis, 30 percent of the poles and wire is estimated to be primary, while the remainder is split 50 percent to primary and 50 percent to secondary. The resulting demand/customer split for those two components is 65 percent to demand-related and 35 percent to customer-related cost.

Underground facilities were classified to demand and customer cost in the same proportion as poles and wires. Line transformers are treated as 100 percent demand related, while services and meters are regarded as 100 percent customer related. Line transformers are allocated to customer classes using non-coincident demands. Services are allocated to rate classes on a weighted-customer basis.

Edmonton Power

Edmonton Power's cost-of-service study is prepared for internal purposes. It is not subject to regulatory approval. The methodology described is that used in the latest study. However, the methods are under review and may change.

Distribution substations are classified 50 percent to demand and 50 percent to on-peak energy. Overhead and underground primary lines, including poles, are also assigned 50 percent to demand and 50 percent to on-peak energy. Line transformers, secondary lines, service and meters are classified and allocated based on specific assignment for a sample of customers.

Newfoundland Power

Distribution substations are classified 100 percent to demand-related cost. Overhead and underground primary lines are classified 67 percent to demand-related cost and 33 percent to customer-related cost based on use of the minimum-plant method. Line transformers are classified 75 percent to demand-related and 25 percent to customer-related cost based on use of the zero-intercept method. Overhead and underground secondary lines, including poles, are assigned 67 percent to demand-related and 33 percent to customer-related cost. Services and meters are classified 100 percent to customer-related cost.

Hydro Quebec

Distribution substations are classified 100 percent to demand-related cost. Overhead primary lines (exclusive of poles) are classified 81.6 percent to demand-related and 18.4 percent to customer-related cost based upon the use of the minimum-plant method. Underground primary lines are classified 86.3 percent to demand-related and 13.7 percent to customer-related cost based upon the use of the minimum-plant method. Poles used to support primary lines are classified 10.3 percent to demand-related and 89.7 percent to customer-related cost based on the use of the minimum-plant method. Line transformers are classified 55.5 percent demand related and 44.5 percent customer related based on the minimum-plant method. Secondary lines (exclusive of poles) are classified 81.5 percent to demand-related and 18.6 percent to customer-related cost based upon use of the minimum-plant method. Poles used to support secondary lines are classified 11.3 percent to demand-related and 88.7 percent to customer-related cost based upon use of the minimum-plant method. All services and meters are classified 100 percent to customer-related cost.

SaskPower

Substations are classified 100 percent to demand-related cost. Three-phase feeders are classified 100 percent to demand-related cost. Urban single-phase primary lines are classified 36.5 percent to demand-related and 63.5 percent to customer-related cost based on the zero-intercept method. Rural single-phase primary lines are classified 19.0 percent to demand-related and 81.0 percent to customer-related cost using the zero-intercept method. Line transformers are classified 39.0 percent to demand-related and 61.0 percent to customer-related cost using the zero-intercept method. All secondary lines, services, and meters are classified 100 percent as customer-related cost.

New Brunswick Power

Distribution substations are classified 100 percent as demand related. All primary lines, including poles, are classified 50 percent demand related and 50 percent customer related based upon consultant's recommendations. Line transformers are classified 75 percent demand related and 25 percent customer related on the same basis. All secondary lines, including poles, are classified 50 percent demand related and 50 percent customer related based upon consultant's recommendations. Services are "not applicable." Presumably, they are customer owned or included elsewhere. Meters are classified as 100 percent customer related.

B. C. Hydro

Distribution substation plant and transformers which are sized to meet the peak demands of customers are classified 100 percent to demand. Primary lines are classified to demand and customer in proportion to a special study that assigned distribution feeder lines 100 percent to demand related and primary line extensions 100 percent to customer related. Distribution-related operating and maintenance expense, depreciation expenses, grants and taxes and related interest and net income expenses are classified to demand and energy in the same proportions as the classification of distribution plant. Customer accounting costs and other customer services costs are classified entirely as customer.

III. APPLICATION OF ALTERNATIVE METHODOLOGIES

A. General

The emphasis in the literature appears to be upon statistical relationships rather than upon an approach that would attempt to identify a causal relationship. A causal relationship can be established by observing the distribution construction required when new or added customers request service. The response will depend on a number of factors such as the class of customer (*e.g.*, residential, small general service, or large general service), the extent to which the area is already served, design practices, and the nature of the utilities' extension policy.

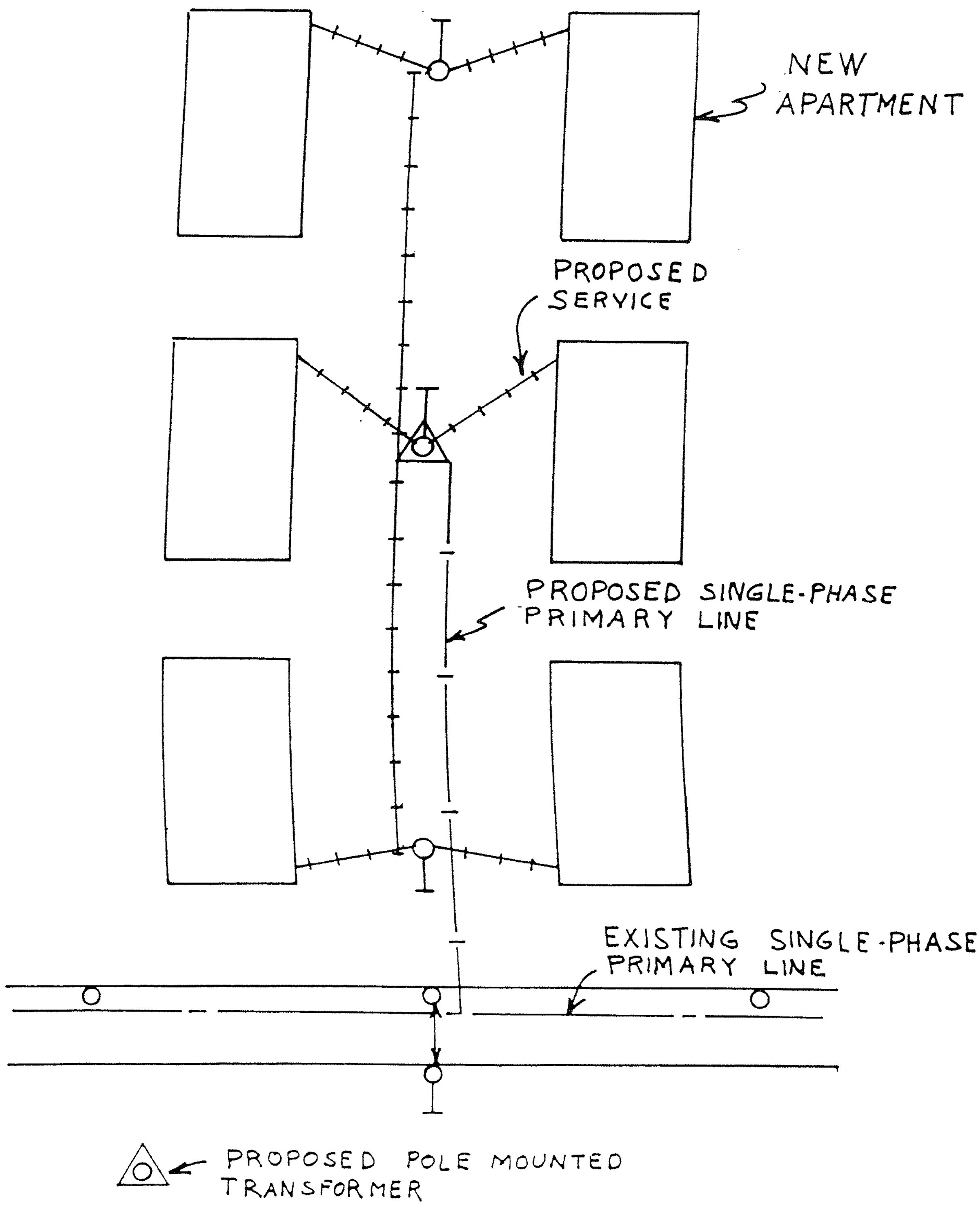
If we choose the residential customer class, since it is most numerous, and assume that service is provided to 100,000 residential customers and that the annual customer growth rate is 1.5 percent, the number of added customers each year will be 1,500. It is reasonable to expect that these customers will fall into the following categories:

- New customers in new multi-family apartments ranging from four customer structures to high-rise (12 or more stories) buildings. The smaller buildings will be served from a transformer-secondary system similar to that used to supply single family homes. A single service wire may supply all of the individual customer meters. A high-rise building may entail a single or three-phase primary cable installed in duct furnished by the building owner, with transformers located on the lower floor, the middle floor and the top floor. Secondary in duct furnished by the building owner will supply customer meters on every third floor.

  The supply of the smaller apartment building requires the extension of the primary system to serve the distribution transformer and the construction of secondary voltage lines if there are a number of similar small apartments in close proximity. The service wire to the apartment buildings and the installation of the required meters completes the construction project. See Figure 1. That figures assumes overhead construction. With underground construction a pad-mounted transformer would be installed at the same

Figure 1

OVERHEAD SUPPLY TO SMALL APARTMENT BUILDINGS



location in the transformer pole. The primary and secondary underground cable, and service cable would follow the same route as the overhead system.

A high-rise building supply is merely a vertical equivalent of the horizontal underground system that would be used to supply the individual apartment buildings.

- New customers in single family residences in a new residential subdivision. A subdivision could include an arrangement with only three or four lots, or many hundreds of lots, depending upon the size of the development. As an example, service could be supplied to only three homes in a 30-lot subdivision. The system could be built initially to serve the full development of 30 lots; however, it is possible that only three have been sold and have homes built thereon.

- New customers in single family residences in existing residential subdivisions. In that event, the only construction required is the installation of a service and meter for each residence.

- New customers in rural areas adjacent to a single-phase primary line. This may require only the installation of a distribution transformer on an existing pole, plus a service and meter. If the customer is located some distance from the existing line, it may be necessary to extend the primary line or construct a secondary line to reach the customer.

This list does not cover all the possible contingencies that may arise in supplying the total of 1,500 new customers. The average annual cost of supplying the added customers will vary considerably; however, for a given category, say single-family residences, it will tend to be about equal to the cost of a subdivision with 95 to 100 percent of lots served. The low cost of supply in an existing subdivision is balanced out by the high cost of a partially developed or undeveloped new subdivision.

The question arises as to the cause of cost. In incremental terms, the customer related cost is the full cost of connecting the added customers to system, including all of the aforementioned facilities. If these new customers purchased no energy, the reimbursement required to save the existing customers harmless would be the annual revenue requirement of these added facilities. Thus, in incremental terms, a "minimum" system has no relevancy. The concept of a minimum system as a measure of customer related cost, with the cost of capacity equal to the excess of that minimum amount, is limited to embedded cost analyses.

Mass statistics can create confusion. Some years ago, Con Edison of New York reported that its distribution system cost was increasing at a substantial rate, with no concomitant increase in the total number of customers served. What was happening was a very rapid growth in the number of customers served at substantial cost in affluent Westchester County in the same timeframe as the wholesale elimination of customers in the Bronx, which had the appearance of a war zone.

British economics literature refers to the concepts of "extensive" and "intensive" cost. The term "extensive," in this instance, would refer to the cost of supplying additional electric customers. The cost would have to cover their added demand imposed on the main primary feeder, distribution substation, transmission system, and generation, along with the investment and expense involved in extending the primary lines, installation of line transformers, secondary lines, services, and meters, as well as customer accounting and collecting. A like increase in demand, caused by an increase in consumption on the part of existing customers would involve only potential reinforcement of the existing distribution system, and the cost of transmission and generation. Since meters and services are generally sized for a large-use customer, the reinforcement will generally be limited to the addition of line transformer capacity and minor primary-line reinforcement. As an example, no additional poles will be required since all customers are served.

The foregoing discussion provides a reasonable basis for assuming that added customers will cause an increase in distribution investment whenever the new residence or business is located in an unserved area. Thus, there is a conceptual basis for recognizing customer-related cost in embedded- and incremental-cost analysis.

B. Alternative Classification of Primary Lines and Poles

Mr. George Baker, in his pre-filed testimony, recommended that all lines between the substation and load center be classified as demand related. A problem arises in that the "load center" is not defined. In the past, it was commonplace for utilities to construct so-called "express" feeders between the substation and the load center. The primary lines then extended in each direction from that point. Current practice is to not construct "express" feeders but instead to serve load throughout the length of all primary lines.

The three-phase feeder portion of the primary distribution system, in terms of cost behavior, responds to the capacity requirement of the load created by the addition of customers, as well as the additional consumption of existing customers. Thus, it can serve as a proxy for the so-called "express" feeder mentioned by Mr. Baker. The remaining single and two-phase and neutral laterals can then be classified between demand-related and customer-related cost in the usual fashion.

Based on our request, the Distribution Engineering planning group of Newfoundland Hydro developed statistics relating to the aggregate length of 4.16, 12.5 and 25 kV feeders in terms of three-phase, two-phase, and one-phase segments for each circuit. Statistics with respect to the total length of secondary distribution lines were also developed. See Appendix A to this report. Thus, it is possible to more accurately split distribution investment between primary and secondary lines, as well as provide a split between three-phase lines and single- and two-phase and neutral laterals.

It is proposed that all three-phase primary lines be classified as 100 percent demand related. The primary laterals are to be split between customer-related and demand-related using the zero-intercept method.

Using the data in Appendix A, the primary circuit length is split between three-phase, two-phase, and one-phase, as shown below.

Type of Circuit	Circuit Length in km	Percent of Total
Three Phase	1,101.3	51.05%
Two Phase	102.6	4.75
One Phase	953.5	44.20
	2,157.4	100.00%

The split between primary and secondary circuit length is as follows:

Type of Circuit	Circuit Length in km	Percent of Total
Primary	2,157.4	75.95%
Secondary	683.2	24.05
	2,840.6	100.00%

Current practice calls for the use of 1/0 AASC conductor for both three-phase main feeders and laterals. On that basis, the total cost for three-phase main feeders, including materials, labor, engineering, project management, load rights, environment, operations cost, overheads and LDC, is $52,000 per km. The median cost of single-phase laterals is $43,500 per km. A research of the conductor sizes used by Hydro for primary lines shows that a substantial percentage of three-phase lines currently exceed 1/0 AASC and have a unit cost that is more than double the unit cost of the 1/0 AASC conductor. This leads to the conclusion that the cost per km difference for existing three-phase feeders is greater relative to single-phase laterals, as compared to the data for new lines using only 1/0 AASC.

In order to arrive at a figure for primary conductors included in three-phase lines, it is necessary to calculate the three-phase conductor length by conductor size. In that analysis, it is assumed that all conductors larger than 1/0 AASC are used only on three-phase lines. The additional amount necessary to arrive at the total length of three-phase line is assumed to be 1/0 AASC. The total length of three-phase line is calculated as the product of three-phase circuit length and number of primary conductors. It is further assumed that the neutral conductor is a reduced size on existing lines, and, where possible, a common neutral is used for both primary and secondary lines. Based on the foregoing, 67.5 percent of primary conductor investment is assumed to be three phase and classified as 100 percent demand related. Details of that calculation are provided in Appendix C. The remainder is split between demand-related and customer-related cost using the zero-intercept method, *i.e.*, 78.3 percent demand related and 21.7 percent customer related, using data from the generic hearing.

The split between primary and secondary conductor investment using the split in length from the foregoing text table, conductor unit cost data for the Hydro Rural Central Area, and adjusting for the assignment of common-neutral conductor, is 69.9 percent to primary conductor and 30.1 percent to secondary conductor. See Appendix C for details of that calculation.

Pole Cost Classification

The split of pole investment between primary and secondary lines is based on the circuit-length data in Appendix A and the assumption that 25 percent of secondary line provides a common neutral conductor and, therefore, occupies the same poles on the primary line. On that basis, the split of pole investment based on the previously provided split in primary and secondary circuit lengths is 37.1 percent to demand-related three-phase lines, 40.5 percent to single and two-phase and neutral primary lines, and 22.4 percent to secondary lines. See Appendix D for details of that calculation.

Pole investment in single-phase and two-phase and neutral lines, and in secondary lines is classified to demand related and customer related using the zero-intercept method.

The zero-intercept approach used by Newfoundland Hydro, in the past, split pole investment between demand-related and customer-related cost on the basis of pole length. While that approach is commonly used, Mr. Baker's concern that length is dictated by ground clearance requirements is well taken. An analysis shows that most poles on the Newfoundland Hydro are 35 feet, unless greater height is required to accommodate multiple circuits, line transformers, street lights, etc. Accordingly, we obtained installed-cost data for 10.7 meter distribution poles for classes 1 through 5. Pole classes differ in terms of the ultimate resisting moment, which in turn is a function of the diameter of the pole at the ground line. A regression analysis prepared on the basis of ground line diameter is provided on the following page. The analysis shows that the zero-intercept cost of 10.7 meter poles is $166.45. That figure is 33.63 percent of the average cost of a ruling size class 5 pole. Thus, 33.63 percent of pole investment will be allocated to the customer-cost component and the remainder to demand-related cost.

Distribution Transformer Classification

Mr. Baker expressed a reservation regarding the use of the zero intercept because of a perceived difference in transformer weight by voltage classification, namely, 4.16, 12.5 and 25 kV. The data provided in Appendix B shows that transformer dimensions and weight are the same for all single-phase transformers up to 18 kV and three-phase transformers up to 25 kV. Note that the 25-kV phase-to-ground voltage is 14.4 kV, so that the single-phase transformers used on a 25 kV circuit fall within the 18 kV category. In view of this, no alternative has been considered to the zero-intercept method used in the classification of distribution transformers.

Services and Meters

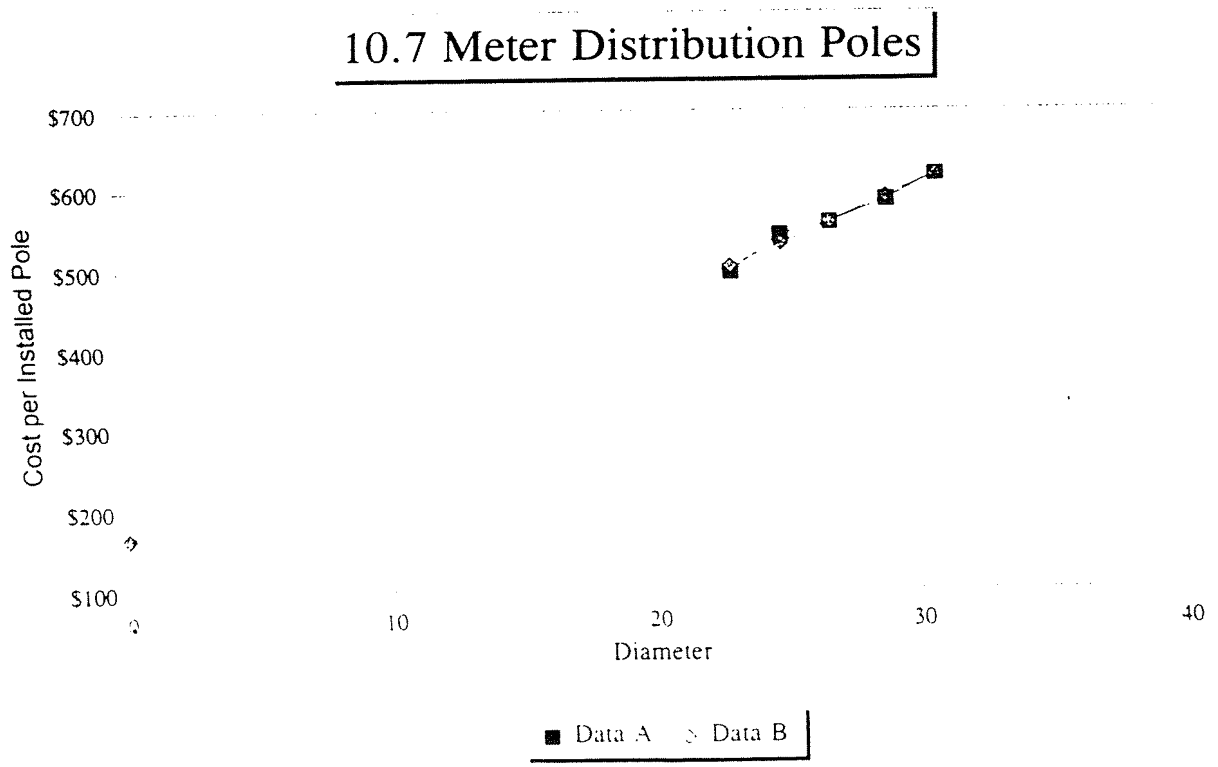
No change in the existing approach of classifying 100 percent of the cost of services and meters is proposed at this time.

POLE INVESTMENT REGRESSION ANALYSIS

Class	Cost / Pole	Installed Cost / Pole	Circumference	Diameter	Calculated Installed Cost / Pole
		$325.0		3.1415927	
1	$292.00	$617.00	99.00	31.513	$616.5
2	$260.00	$585.00	93.00	29.603	$589.2
3	$232.00	$557.00	86.00	27.375	$557.4
4	$217.00	$542.00	80.00	25.465	$530.1
5	$170.00	$495.00	74.00	23.555	$502.8
0				0.000	$166.4

Regression Output:

Constant	**$166.446**
Std Err of Y Est	8.580
R Squared	0.9738004
No. of Observations	5
Degrees of Freedom	3
X Coefficient(s)	$14.281
Std Err of Coef.	1.352



IV. CONCLUSION AND RECOMMENDATIONS

A. Conclusions

The following paragraphs describe the conclusions reached regarding the classification between customer and demand related cost based on our literature review and survey of current practices.

Academic Research

Academic research as well as technical papers by practitioners, with few exceptions, favor the use of a customer component. Use of the zero intercept method is favored since it avoids the classification of small components of total cost to demand that is inherent in the minimum plant method. Data availability may be an issue and limit the options available to the analyst. Criticism of the calculation of customer components in the text by Bonbright does not appear justified based upon the source relied upon.[18]

U.S. Utility Practice

A review of U.S. practice based upon regulatory commission orders shows that most utilities classify distribution between demand and customer related cost.

Canadian Utility Practice

Virtually all Canadian utilities classify 100 percent of distribution substation cost as demand related. Two utilities classify 100 percent of three-phase primary lines as demand related. Single-phase primary laterals are classified to demand-related and customer-related cost based on consultant's recommendations or the use of minimum plant or zero-intercept methods. The range of classification of primary lines to the customer component is 18.4 to 100 percent,

[18] See text pages 6 and 7.

with an average of 50.3 percent. Primary line poles, when separately classified, range from 63.5 to 100 percent customer related.

Line transformer classification to the customer component ranges from zero to 61 percent, with an average of 31.1 percent. Secondary line classification to the customer component ranges from 18.6 to 100 percent, with an average of 60.3 percent. Secondary line poles, when separately classified, range from 33 to 100 percent classified as customer related, with an average of 74.3 percent. All Canadian utilities classify services and meters 100 percent to customer-related cost.

B. <u>Recommendations</u>

The following paragraphs summarize our recommendations with the classification of distribution costs between demand-related and customer-related components by Newfoundland Hydro.

Distribution Substation Costs

The present practice is to classify distributors' substation costs 100 percent to demand. The wisdom of that approach is confirmed by our research and no change is recommended.

Primary Line Cost

Primary line cost consists of conductor and pole cost. Based upon the apparent trend in Canadian practice and giving recognition to cost behavior, it is proposed that all three-phase primary lines be classified 100 percent to demand.

It is recommended that the remaining primary conductor investment be split between demand-related and customer-related cost using the same zero-intercept methodology used in the past.

With respect to the investment in poles, the use of the zero-intercept method in a fashion that recognizes pole diameter at the ground line rather than length, as described in Chapter III of this report, is recommended.

No change in the classification of secondary conductor is proposed. The current approach is based upon use of the zero-intercept method.

It is recommended that the classification of secondary-distribution pole investment utilize the same approach recommended above for primary-line pole investment.

Distribution Transformers

The present practice of Canadian utilities supports use of the zero-intercept method which has been used in the past by Newfoundland Hydro to classify cost between demand related and customer related. As discussed in Chapter III of this report, Mr. Baker's concern about the influence of transformer weight difference by voltage class appears to be unfounded. Continued use of the zero-intercept method is recommended.

Secondary Line Cost

It is recommended that the zero-intercept method continue to be used to classify secondary conductor cost between demand and customer related. With respect to secondary poles, it is recommended that the zero-intercept methodology be revised to conform to the approach using pole-ground-line diameter in the regression analysis, as discussed in Chapter III of this report.

Services and Meters

It is recommended that 100 percent of the cost of services and meters continue to be classified to the customer component. This approach is consistent with Canadian practice elsewhere.

APPENDIX A

PRIMARY AND SECONDARY CIRCUIT LENGTH

Newfoundland & Labrador Hydro

4.16kV Feeders		Primary (km)			Secondary (km)
Feeder	Area	3-phase	2-phase	1-phase	
547-11	Labrador	14.8	0.0	1.6	3.3
262-1	Western	4.9	0.4	4.3	5.5
142-1	Labrador	4.5	0.0	9.9	8.0
230-1	Labrador	4.1	0.1	3.8	2.3
HU-2	Lab City	3.9	0.0	0.1	N/A
QZ-2	Lab City	3.4	0.0	0.5	N/A
240-1	Central	3.3	0.2	1.3	3.7
QZ-4	Lab City	3.3	0.7	1.6	N/A
265-1	Northern	3.0	0.0	3.0	3.7
432-1	Labrador	3.0	0.8	2.6	4.1
568-3	Southern	3.0	0.8	0.2	4.9
HU-3	Lab City	2.7	0.2	0.5	N/A
QZ-5	Lab City	2.6	0.0	0.0	N/A
420-8	Labrador	2.6	0.0	0.7	N/A
QZ-6	Lab City	2.6	1.2	0.9	N/A
HU-1	Lab City	2.5	0.5	0.2	N/A
BA-5	Lab City	2.5	0.3	0.5	N/A
HU-4	Lab City	2.4	0.0	0.4	N/A
320-2	Western	2.1	2.7	0.3	7.1
588-2	Southern	2.0	0.0	0.1	0.1
651-3	Central	2.0	0.5	2.8	6.2
280-1	Labrador	2.0	0.4	4.2	5.6
BA-4	Lab City	2.0	0.6	0.0	N/A
QZ-3	Lab City	1.9	0.3	0.8	N/A
766-1	Central	1.6	0.0	0.0	1.0
180-3	Central	1.5	3.9	0.5	6.1
568-2	Southern	1.5	1.2	1.1	5.2
222-2	Central	1.5	0.3	0.3	2.1
420-7	Labrador	1.3	0.0	0.1	N/A
469-1	Labrador	1.3	0.0	1.7	1.8
588-1	Southern	1.3	1.1	2.3	5.5
547-7	Labrador	1.3	0.0	0.0	0.0
BA-1	Lab City	1.3	0.2	0.1	N/A
361-1	Central	1.2	0.3	9.1	5.8
BA-3	Lab City	1.2	0.0	0.0	N/A
527-1	Labrador	1.0	0.2	2.1	2.2
BA-2	Lab City	1.0	0.1	0.5	N/A
568-4	Southern	1.0	0.1	0.2	1.4
HL-2	Lab City	0.9	0.0	1.3	N/A
420-13	Labrador	0.9	0.0	0.0	N/A
744-1	Northern	0.9	0.0	1.7	1.1
116-1	Labrador	0.8	0.0	6.1	2.3
360-1	Central	0.7	4.8	5.6	5.1
QZ-1	Lab City	0.5	0.6	0.8	N/A
191-1	Southern	0.4	0.0	0.4	1.2
837-1	Northern	0.3	0.3	1.1	0.4
180-2	Central	0.3	1.8	0.1	2.7
HL-1	Lab City	0.3	0.7	1.7	N/A
130-1	Northern	0.2	0.3	3.5	2.7
320-3	Western	0.1	0.4	0.0	0.4
700-4	Northern	0.0	0.0	0.0	0.0
245-1	Southern	0.0	0.2	5.4	0.9
260-2	Central	0 0	0.0	3.2	1.3
272-1	Labrador	0.0	0.7	1.8	1.1
199-1	Southern	0.0	0.1	0.9	0.6
		105.0	27.1	91.9	105.4

Newfoundland & Labrador Hydro

12.5kV Feeders		Primary (km)			Secondary (km)
Feeder	Area	3-phase	2-phase	1-phase	
129-1	Western	30.3	0.0	23.4	8.5
129-2	Western	12.2	0.0	5.0	8.5
129-3	Western	14.0	0.0	4.1	4.7
130-2	Northern	0.0	0.0	24.3	0.6
150-1	Western	4.4	0.0	19.5	12.2
159-1	Western	2.0	0.0	26.8	8.8
175-4	Western	21.1	0.0	3.7	7.0
175-5	Western	13.2	0.0	1.1	1.0
175-6	Western	21.3	0.5	22.2	18.2
175-7	Western	0.0	0.0	0.7	0.1
180-4	Central	9.1	2.6	1.9	8.4
180-5	Central	14.1	0.4	13.3	16.4
180-6	Central	18.3	4.6	17.7	14.2
189-1	Northern	2.5	0.0	4.2	3.4
211-1	Central	3.2	6.4	3.5	6.0
222-3	Central	0.0	0.6	8.7	0.1
265-2	Northern	0.0	0.0	9.8	1.2
268-1	Central	0.2	0.0	0.8	1.0
282-1	Western	8.0	1.8	26.2	14.8
282-2	Western	10.5	0.6	6.1	11.2
299-1	Central	3.7	1.1	3.4	7.0
299-1	Western	1.9	0.0	9.5	9.6
299-2	Central	12.7	5.3	7.2	7.7
300-1	Northern	0.2	0.3	9.1	4.7
320-1	Western	20.7	0.4	2.5	9.4
320-3	Western	2.6	0.0	0.7	1.4
320-4	Western	8.0	0.0	21.3	4.1
336-2	Central	0.0	4.7	4.2	4.6
337-1	Central	0.1	0.2	1.0	1.7
354-1	Central	0.2	0.4	1.1	1.3
356-4	Central	12.2	2.3	2.8	11.0
356-6	Central	10.9	0.3	4.2	3.7
356-7	Central	3.2	1.1	2.9	8.3
360-2	Central	0.0	7.7	3.7	2.7
398-1	Central	0.3	0.6	9.0	4.6
399-1	Western	12.6	0.0	2.7	15.4
399-2	Western	16.0	0.0	3.8	3.9
401-2	Central	0.0	0.0	6.3	3.0
420-11	Labrador	3.6	0.0	0.2	N/A
420-12	Labrador	7.1	0.1	2.6	N/A
420-3	Labrador	1.3	0.0	1.7	N/A
420-9	Labrador	0.6	0.0	0.9	N/A
487-1	Northern	18.2	0.0	21.0	8.7
487-2	Northern	13.2	0.4	6.6	12.5
635-1	Western	3.0	0.0	26.0	9.2
635-3	Western	29.5	1.1	34.2	22.6
638-1	Central	4.3	0.0	4.8	6.4
651-2	Central	0.0	4.7	3.8	3.0
651-4	Central	23.9	4.4	9.0	10.4
651-5	Central	11.1	1.4	11.1	12.8
671-1	Western	2.3	0.0	0.3	0.9
700-2	Northern	3.2	0.0	3.4	8.9
700-3	Northern	11.9	0.0	20.5	17.4
700-5	Northern	0.0	0.0	14.6	3.7
700-6	Northern	21.7	2.2	61.3	24.7
700-7	Northern	25.0	0.0	18.0	7.7
791-1	Central	13.0	0.0	0.1	0.0
		482.3	56.1	558.7	399.2

Newfoundland & Labrador Hydro

25kV Feeders		Primary (km)			Secondary (km)
Feeder	Area	3-phase	2-phase	1-phase	
487-3	Northern	0.0	0.0	44.9	5.4
262-2	Western	0.0	0.0	36.4	2.4
444-1	Central	41.0	0.4	36.2	13.7
336-1	Central	20.0	0.5	30.0	12.2
651-1	Central	30.3	0.0	28.8	8.3
356-1	Central	52.5	1.6	27.6	14.0
370-1	Central	34.6	0.0	27.0	33.3
222-1	Central	34.0	14.0	12.2	10.6
547-4	Labrador	1.3	0.0	7.5	9.9
700-1	Northern	48.9	0.0	7.1	2.6
547-7	Labrador	43.5	2.6	6.2	11.2
260-1	Central	17.6	0.0	5.9	0.0
356-3	Central	15.6	0.0	5.7	2.4
547-3	Labrador	2.3	0.0	3.4	5.8
547-10	Labrador	10.6	0.1	3.0	11.7
547-6	Labrador	1.9	0.0	2.8	5.8
401-1	Central	21.9	0.0	2.6	4.4
547-5	Labrador	2.9	0.0	2.4	7.5
370-2	Central	16.4	0.0	2.2	0.2
180-1	Central	29.5	0.0	2.0	0.2
356-2	Central	0.0	0.0	1.9	0.0
547-11	Labrador	14.8	0.0	1.6	3.3
547-2	Labrador	5.0	0.0	1.5	5.8
547-1	Labrador	6.3	0.0	1.4	0.2
651-7	Central	15.5	0.0	1.2	2.5
568-1	Southern	25.2	0.1	0.6	2.1
356-8	Central	2.0	0.2	0.6	3.0
547-15	Labrador	4.2	0.0	0.0	0.0
547-17	Labrador	3.9	0.0	0.0	0.0
547-16	Labrador	12.3	0.0	0.0	0.0
		514.0	**19.4**	**302.9**	**178.6**

APPENDIX B

TRANSFORMER WEIGHT BY VOLTAGE CLASS

OUTLINE DIMENSIONS - TYPE O.N.A.N. UP TO 18 kV (125 kV BIL) DIRECT TO POLE MOUNTING BUILT TO C.S.A. C2

SINGLE PHASE — STANDARD LOSSES AND IMPEDANCE

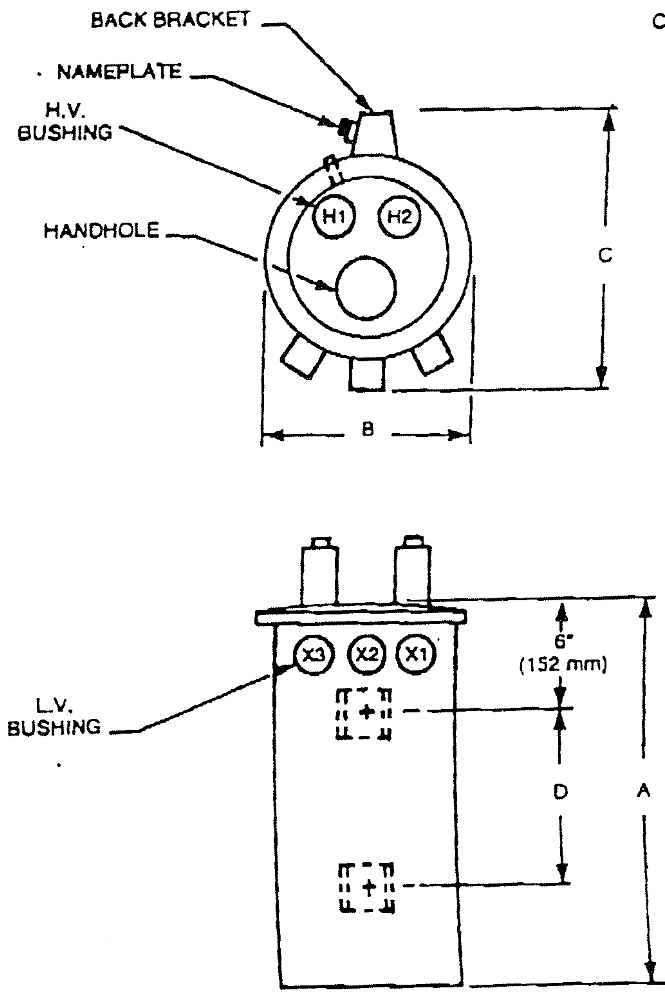


Fig. 1

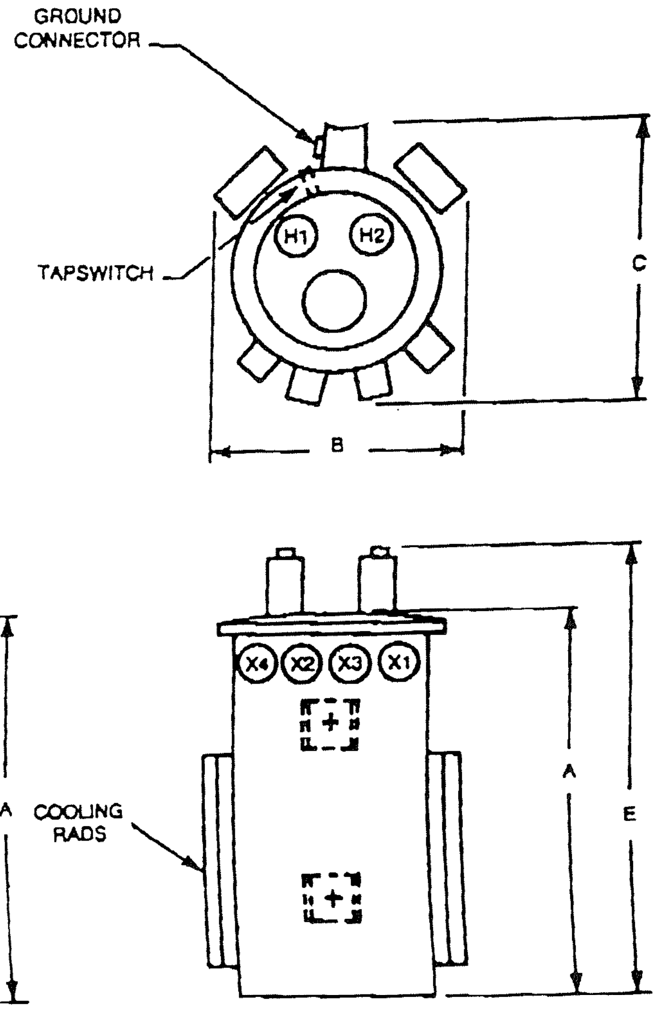


Fig. 2

(HANGER IRONS AND ADAPTER PLATES AVAILABLE UPON REQUEST)

NO.	K.V.A.	FIG.	A		B		C		D		E		QTY. OF OIL		APPROX. WT.	
			Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Gals	litres	Lbs.	kg
1	10	1	22 1/2	572	19	485	21 1/2	546	14 1/2	370	34	863	7	31.8	260	118
2	15	1	22 1/2	572	19	485	21 1/2	546	14 1/2	370	34	863	7	31.8	274	124
3	25	1	26 1/2	673	21	535	23 1/2	597	14 1/2	370	38	965	11.7	53.1	390	177
4	37	1	32 1/2	826	21	535	23 1/2	597	14 1/2	370	44	1118	15	68.1	490	222
5	50	1	35 1/2	902	23	585	25 1/2	648	21 1/2	550	47	1194	22	100.0	645	293
6	75	2	40 1/2	1029	25	635	27 1/2	699	21 1/2	550	52	1321	32	145.3	856	389
7	100	2	37 1/2	953	29	735	30 1/2	775	21 1/2	550	49	1245	31.5	143.0	980	445
8	167	2	37 1/2	953	46 1/2	1180	32	813	28 1/2	730	49	1245	41	186.1	1375	625

OUTLINE DIMENSIONS - TYPE O.N.A.N. UP TO 25 kV (150 kV BIL) DIRECT TO POLE AND PLATFORM MOUNTING TO CSA C2

THREE PHASE — STANDARD LOSSES AND IMPEDANCE

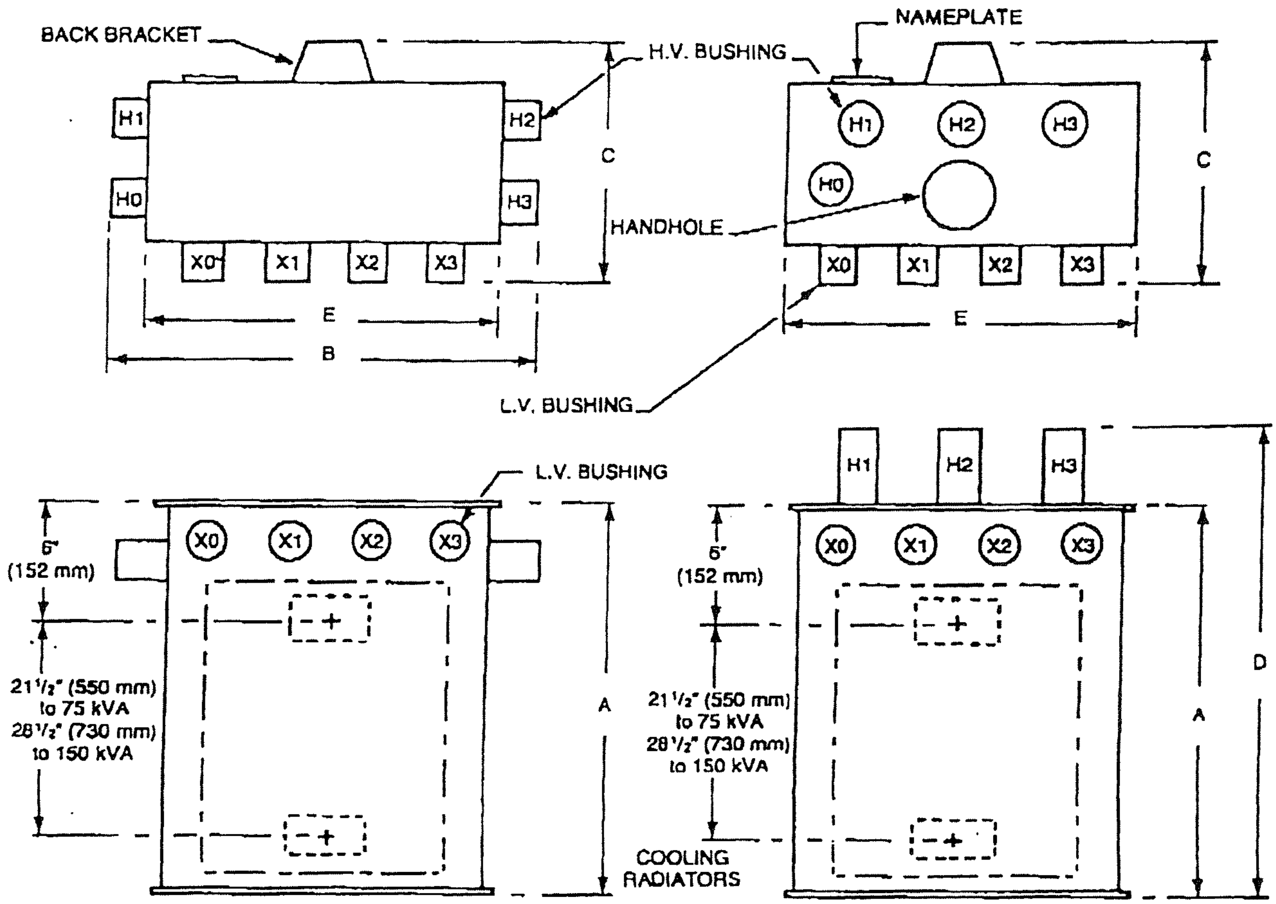


Fig. 1 Fig. 2

(HANGER IRONS AND ADAPTER PLATES AVAILABLE UPON REQUEST)

NOTES: 1) For 15 kV reduce dim. "D" by 6" (152 mm)
2) Back brackets supplied to 150 kVA only
3) Fig 1 applies up to 225 kVA 5 - 8.66 kV class
4) Fig 2 applies up to 225 kVA above 8.66 kV class and all 300 - 500 kVA.

NO.	K.V.A.	A		B		C		D		E		QTY. OF OIL		APPROX. WT.	
		Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Ins.	mm	Gal	litres	Lbs.	kg
1	15	33	838	41	1041	24	610	45	1143	33	838	28	106	600	272
2	30	33	838	41	1041	25	635	45	1143	33	838	31	117	750	340
3	45	33	838	44	1117	29	737	45	1143	36	914	39	148	915	415
4	75	33	838	51	1295	32	813	45	1143	43	1092	59	223	1290	585
5	112	40	1016	54	1372	34	864	52	1321	46	1168	78	295	1820	825
6	150	40	1016	55	1397	38	965	52	1321	47	1194	89	337	1930	875
7	225	40	1016	61	1549	40	1016	52	1321	53	1346	106	401	2930	1329
8	300	40	1016	62	1575	43	1092	52	1321	54	1372	112	424	3070	1393
9	500	48	1219	74	1880	45	1143	60	1524	66	1676	167	632	4815	2184

APPENDIX C

CALCULATION OF SPLIT OF CONDUCTOR COST BETWEEN PRIMARY AND SECONDARY

CALCULATION OF PRIMARY AND SECONDARY CONDUCTOR COST

Total Cost of Conductor

The first step in the split of primary and secondary conductor cost is to calculate the total cost of primary conductor and secondary conductor using unit costs developed for Hydro's Central Area. The calculation of total primary conductor cost of $7,113,121 is provided in Table C-1, using conductor length data by conductor size, and corresponding unit price data.

The calculation of total secondary cost is based upon a secondary circuit length of 683.2 km shown on page 23 of the text of this report, multiplied by three conductors per circuit, and by an average unit cost per meter. The resulting figure is $3,253,330. The unit cost of $1.5873 per meter for secondary conductor was developed using the data shown in Table C-2.

Impact of Common Neutral

The secondary line neutral conductor is used as a common neutral for both primary and secondary lines whenever the primary and secondary lines occupy the same poles. It is conservatively estimated that 25 percent of the secondary circuit occupies the same poles as primary circuit. The length of this common neutral is 25 percent of the total secondary circuit length of 683.2 km or 170.8 km. Cost of that common neutral is estimated as the product of 170.8 km $\times$ 1,000 $\times$ $1.5873 or $271,110.84. One half of that amount, or $135,555, is reassigned to primary conductor cost.

The total primary conductor cost, adjusted for the impact of using a common neutral, is $7,248,676.16, calculated as $7,113,121 plus $135,555. The total adjusted secondary conductor cost is $3,253,330 less $135,555, or $3,117,775.

TABLE C - 1

Calculation of Total Primary Conductor Cost

Newfoundland Labrador Hydro

Conductor Size	Length of Conductor - meter	Unit Costs - $/meter	Conductor Cost
1/0aasc	3,017,058	0.77	$2,323,135
2acsr	1,451,711	0.65	943,612
4/0aasc	1,402,691	1.53	2,146,117
4cu	287,352	1.10	316,087
2/0aasc	232,506	1.08	251,106
477al	89,026	3.12	277,761
636al	63,991	4.86	310,996
266.8acsr	92,526	3.32	307,186
2cu	126,802	1.87	237,120
	6,763,663		$7,113,121

TABLE C - 2

Average Cost of Secondary Line - Based on Hydro Rural Central Area

Newfoundland Labrador Hydro

Conductor Size	Conductor - meter	Unit Costs - $/meter	Conductor Cost
#2 triplex	4,187	1.73	$7,244
#2 cu.	10,644	3.06	32,571
#4 cu.	276,054	2.07	571,432
#6 cu.	39,518	1.53	60,463
#2 al.	101,773	1.01	102,791
4/0 al.	13,082	2.25	29,435
1/0 al.	70,448	1.32	92,991
2/0 al.	141,145	1.11	156,671
#4 triplex	27,670	1.26	34,864
#6 duplex	6,838	0.89	6,086
1/0 cu.	2,117	2.94	6,224
	693,476	1.5873	$1,100,770

Cost of Three-Phase Primary

The calculation of the cost of the three-phase primary of $5,275,765 is provided in Table C-3. The total length of the three-phase circuit is 1,101.3 km as shown on page 23 of the text. Cost includes both the phase conductors and a reduced-size neutral. Average cost of the neutral conductor shown on that table is $0.8052 per meter. The three-phase primary is 51.05 percent of total primary as shown in the text table on page 23. Therefore, the length of common neutral in the three-phase segment is 170.8 km × 0.5105, or 87.193 km. The impact of the common neutral on the three-phase conductor investment is 170.8 × 1,000 × (0.8052 - 0.7937), or $1,964. The adjusted three-phase conductor cost is $5,275,765 - 1,964, or $5,273,800. The figure of $0.7937 is the apportioned cost of the secondary line common neutral or one half of the aforementioned unit cost of $1.5873.

Cost Ratios

The three-phase primary conductor investment, which is to be classified as 100 percent demand related, is 72.76 percent of total primary conductor cost, *i.e.*, $5,273,800/7,248,676.16. The remaining primary conductor investment is 27.24 percent of the total primary conductor investment. That percentage of primary conductor cost plus all secondary conductor cost is to be classified using the zero-intercept approach.

The split of conductor investment between primary and secondary is $7,248,676/ (7,248,676.16 + 3,117,775.08), or 69.9 percent to primary and the remainder, 30.1 percent, to secondary.

TABLE C-3

Calculation of Three Phase Primary Line Conductor Cost

Newfoundland Labrador Hydro

Conductor Size		Length of Conductor - meter		Unit Costs - $/meter		Conductor Cost		
Phase	Neutral	Phase	Neutral	Phase	Neutral	Phase	Neutral	Total
1/0aasc	1/0aasc	1,423,160	474,387	0.77	0.77	1,095,833	365,278	1,461,111
4/0aasc	1/0aasc	1,402,691	467,564	1.53	0.77	2,146,117	360,024	2,506,141
2/0aasc	1/0aasc	232,506	77,502	1.08	0.77	251,106	59,677	310,783
477al	4/0aasc	89,026	29,675	3.12	1.53	277,761	45,403	323,164
636al	4/0aasc	63,991	21,330	4.86	1.53	310,996	32,635	343,631
266.8acsr	1/0aasc	92,526	30,842	3.32	0.77	307,186	23,748	330,935
		3,303,900	1,101,300			4,388,999	886,765	5,275,765

APPENDIX D

CALCULATION OF SPLIT OF POLE INVESTMENT BETWEEN PRIMARY AND SECONDARY

CALCULATION OF PRIMARY AND SECONDARY POLE COST

The length of secondary line that is assumed to occupy the same pole line as primary line is 25 percent of the total length of secondary or 170.8 km (683.2 $\times$ 0.25). If the poles in that common section are to be allocated equally to primary and secondary, the adjusted length of primary pole line is 2,157.5 km - ½(170.8), or 2,072 km. Adjusted secondary length is 683.2 - ½(170.8), or 597.8 km. Total adjusted length is 2,669.8 km.

Pole line investment assigned to three-phase primary and classified 100 percent to demand $= \dfrac{1{,}101.3}{2{,}669.8}$ or 41.2 percent

Pole line investment assigned to other primary lines $= \dfrac{2{,}072-1{,}101.3}{2{,}669.8}$ or 36.4 percent

Pole line investment assigned to secondary lines $= \dfrac{597.8}{2{,}669.8}$ or 22.4 percent

Memorandum

To: Glenn Mitchell

From: John Brickhill

Date: April 23, 2001

Re: Distribution Study

The "Study of Distribution System Cost Classification" (Distribution Study) was prepared by Foster Associates, Inc. for Newfoundland and Labrador Hydro in 1996. The results of the 1996 study were updated in December 1998. The findings of the 1998 Distribution Study form the basis of work incorporated in the current cost of service model. The zero intercept results, however, have been updated to include data from the 1999/2000 District Work Order Price List. The new results are presented in the attached memo.

Memo

To: John Brickhill

From: Brian Chabot, Karen Morgan

CC:

Date: 04/12/2001

Re: Zero Intercept Analysis

The zero intercept method establishes the customer-related component of distribution costs using regression analysis to determine the relationship between the capacity of different sizes of equipment and the unit cost thereof. In order to remove the effects of inflation, either current costs of new facilities or price-level adjusted average unit costs are used. The zero intercept method was applied to distribution poles, distribution transformers and distribution conductor.

The data for the distribution poles analysis came from a 1996 study prepared by Foster Associates. The data for the conductor analysis was provided by Hydro in an Access database file, PoleConductor.mdb. Transformer data came from the Loss Allocation model. Equipment cost data came from the 1999-2000 District Work Order Price List. The regression analyses were performed in EXCEL.

<u>Poles</u>

Pole investment is commonly split between demand-related and customer-related costs based on a zero-intercept analysis of pole length. However, at the 1992 Generic hearing, concerns were raised that length was affected by ground clearance requirements. An analysis of the NLH system showed that most poles on the system are 10.7 meters (35 feet), unless greater height is required to accommodate multiple circuits, line transformers, street lights, etc. Accordingly, a regression analysis was prepared on the basis of ground line diameter of 10.7 meter poles. The equation results were as follows:

Installed Cost = 431.44 + 14.28 Ground Line Diameter

The estimated minimum cost derived from this equation was $431.44. This figure is 54.3% of the average cost of a ruling size class 4 pole. Therefore, approximately 54% of costs are customer-related with the remaining approximately 46% being demand related.

Transformers – T4 Transformers

An equation relating various kVa ratings and associated total costs was estimated. The results were as follows:

$$\text{Transformer Cost} = 1442.26 + 19.24 \text{ kVa}$$

At zero kVa, the minimum cost was $1442.26. The ratio of minimum to average unit cost was 63.9%, indicating that almost 64% of transformer costs were customer related.

Conductor – Excluding service drops and data where x-sectional data unknown

The X-sec area for 5 conductor types was regressed against material costs. The resulting equation was as follows:

$$\text{Material Cost} = 0.3562 + 4.16501\text{E-}06 \text{ X-sec area}$$

At zero area, the minimum cost was $0.36. The ratio of minimum to average unit cost was 41.6% indicating that almost 42% of conductor costs were customer related.