Prospective Cost of Service Study

For Fiscal Year Ending

March 31, 2008

Manitoba Hydro

Electric Rates & Regulatory Department
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MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2008

TABLE OF CONTENTS

MANITOBA HYDRO
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MARCH 31, 2008

EXECUTIVE SUMMARY

A Cost of Service Study ("COSS") is a method of allocating a utility's cost to the various classes of customers that it serves. Its purpose is to determine a fair sharing of the utility's Revenue Requirement among the customer classes. While there are many allocation methods, the central aim is always to allocate costs to the customer classes on the basis of known customer characteristics. The cost study conducted at Manitoba Hydro is an average (embedded) study in that the unit costs represent the average to serve all customers in a rate class or subclass based upon funds historically invested in plant in service.

Manitoba Hydro's COSS is a Prospective Study. That is, while historic investment has a significant role in determining the costs, the study utilizes forecast costs for the next fiscal year. This provides a basis for testing rates that are proposed for the next fiscal year.

The results of the study indicate the degree to which the rate class/subclass revenue recovers allocated costs. Although the study has the appearance of exactness, it does not disclose the actual cost of serving a particular customer or group of customers within a customer class, it only provides an approximation of such costs. This is because there are many judgements involved in the process of classifying and allocating costs, particularly those costs related to capital investment. There is no right or wrong way of allocation, as each utility's operating characteristics and reasons for capital investment are not necessarily the same. The objective for the utility is to select a method which best represents cost causation and the equitable sharing of costs among the customer rate classes.

Since at least 1997 Manitoba Hydro has been concerned that the COSS results were becoming distorted as a result of the increasing significance of export revenues. As a result, Manitoba Hydro began to examine its cost of service methodology and consider changes that would keep the COSS results relevant and fair in light of the changing marketplace. The Public Utilities Board ("PUB") concurred with these concerns and noted in Order 101/04 that further rate increase applications would only be considered following a full review of the methodologies employed in the Corporation's future Cost of Service Studies.

Following these proceedings which resulted in Order 117/06, the PUB gave general approval to the Corporation's Recommended methodology, but also directed Manitoba Hydro to make some specific modifications to the recommended model. The most significant of these changes assign a much larger portion of Generation and Transmission costs against exports. The assignment of these additional costs to exports has a similar effect on domestic class Revenue Cost Coverage ("RCC") ratios as the previous export revenue assignment methodology, in which cost allocation to the domestic rate classes limited the assignment of export revenues to only the Generation and Transmission functions.

Manitoba Hydro believes that this approach to cost allocation against export sales is not entirely appropriate for the following reasons:

(1) Fixed costs of Hydraulic Generation are not incurred to support Opportunity Exports; and

(2) Costs related to Thermal Generation capital, operating/maintenance and fuel, that are incurred to provide system reliability and which mostly benefits domestic customers. When prices in the export market are sufficiently high, it becomes economic to dispatch thermal stations, but they would not have been built, nor would the ongoing operating and maintenance costs be incurred just to facilitate occasional sales that are economic.

The Prospective Cost of Service Study for 2008 ("PCOSS08") was prepared to comply with the directives in PUB Order 117/06. Significant changes from the Recommended methodology include:

- Allocating Generation costs on the basis of marginal cost weighted energy using twelve SEP time periods rather than four;
- Utilizing a single Export Class and allocate costs to that class in a manner comparable to the allocation of cost to domestic classes;
- Directly assigning the cost of Trading Desk, MAPP and MISO; thermal plant fuel; water rentals and power purchases to the Export Class. Any associated energy is considered to serve export load;
- Directly assigning the costs of Demand Side Management ("DSM"), with the associated DSM energy savings considered to serve the export market. Consequently the costs of the DSM initiatives are no longer directly assigned to individual customer classes; and

– Allocating Transmission costs on the basis of demand only. The distinction between those lines serving the export market (allocated on energy) and all other transmission lines (allocated on demand) as done in the recommended version of PCOSS06 is no longer made.

Manitoba Hydro has also included results to illustrate the effects on RCCs of recognizing the current deficiency in retained earnings relative to the target 75:25 debt/equity ratio. That is, because retained earnings are deficient relative to the target, it is reasonable that RCCs should reflect this deficiency. As rate increases are implemented and retained earnings increase, RCCs will increase correspondingly.

The resulting RCC's under the two methodologies are:

CUSTOMER CLASS	**RCC ORDER 117/06**	**RCC REFLECTING RETAINED EARNINGS DEFICIENCY**
Residential	96.4%	75.2%
GSS Non-Demand	104.3%	82.1%
GSS Demand	107.2%	82.9%
GSM	101.1%	78.0%
GSL 0 – 30 kV	90.4%	69.3%
GSL 30 – 100 kV	103.7%	79.6%
GSL > 100 kV	108.7%	82.7%
Area & Roadway Lighting	105.8%	88.4%

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SECTION A

COST OF SERVICE METHODOLOGY

Cost of Service History

Manitoba Hydro has conducted cost of service studies since the mid 1970s. While significant changes have occurred on an evolutionary basis, cost of service studies filed with previous Rate Applications follows generally the same principles that were adopted with early cost of service studies. The significant changes relate mainly to the ability to better forecast customer loads and load factors, and special treatment of items such as DSM or net export revenues. The key features of the study that have remained relatively unchanged since the late 1970s are:

– The study deals with embedded costs (although in 1992 the study changed from being historic costs to forecast costs).
– The study functionalizes utility costs into five main groups: Generation; Transmission; Subtransmission; Distribution Plant and Distribution Services (or Customer Service).
– The study classifies Subtransmission costs on the basis of Non-Coincident Peak Demand only.
– The study allocates Distribution plant costs on the basis of Non-Coincident Peak Demand and Customer Count. The proportion classified on the basis of Demand has been set at 60% since 1991.
– The study classifies Customer Service costs on several ways, but all are customer-related; allocation among classes is based on the number of customers in each class. For some costs customer numbers are weighted differently for each class, reflecting differences among the classes in the cost to provide the service.
– The study allocates Transmission Demand-related costs on the basis of both winter peak (top 50 coincident hours) and summer peak (also top 50 coincident hours). Prior to 2004 these costs were allocated on the basis of winter peak only.
– The study allocates a credit for net export revenue to all domestic in proportion to total allocated costs of all functions. This method was endorsed by the PUB in 2006.

Cost of Service Review

Since at least 1997 Manitoba Hydro has been concerned that the COSS results were becoming distorted as a result of the increasing significance of export revenues. As a result, Manitoba Hydro began to examine its cost of service methodology and consider changes that would keep the COSS results relevant and fair in light of the changing energy marketplace.

In anticipation of the 2006 Cost of Service Review the Corporation provided four versions of its 2006 PCOSS for discussion purposes. The four methodologies were:

1. Manitoba Hydro's Current methodology;

2. The implementation of the NERA Report recommendations;

3. Generation Vintaging Method whereby low cost generating resources on the Winnipeg River were dedicated to domestic customers; and

4. Manitoba Hydro's Preferred or Recommended methodology.

The current methodology was comparable to that used in PCOSS04, and determined net export revenue by deducting variable power and water rental costs from gross export revenue. Net export revenue was then allocated on the basis of class Generation and Transmission costs.

The approach recommended in the NERA Report used marginal cost weighted energy for the allocation of Generation costs. That is, energy in each of four time periods (winter and summer on- and off-peak) is weighted according to the average marginal cost in each of these time periods. Transmission classified as export/import is allocated on the basis of energy at Generation, with all other Transmission costs allocated on 2 CP Demand. This approach also includes an Export customer class to which is allocated Generation and Transmission costs on the same basis as domestic classes. Residual net export revenue is assigned on the basis of total allocated costs.

The Generation Vintaging Method allocated the lowest cost Generation (namely Winnipeg River Generation) only to domestic customers, with remaining domestic load and the Export Class allocated the cost of all other Generation. As in the NERA scenario, the scenario also included an Export customer class that was allocated Generation and Transmission costs on the same basis as domestic classes, with the residual net export revenue assigned on the basis of total allocated costs.

Manitoba Hydro's Recommended methodology was a modification of the NERA Method that provided separate treatment of Firm and Opportunity Exports. Firm exports attracted a full share of embedded Generation and Transmission cost as recommended in the NERA study. Opportunity Exports would attract only variable costs (water rentals, thermal fuel and imports) as in the Current Method. Net export revenues after allocation of costs would continue to be allocated among domestic classes on the basis of total costs.

A hearing was held in May and June of 2006 to review the various PCOSS alternatives, and evaluate how each addressed the concern that COSS results were becoming distorted as a result of the increasing significance of export revenues. The alternatives, as well as alternative treatments proposed by Intervenors, were subject to extensive review by the PUB, Manitoba Hydro and Intervenors during the proceeding. The resulting PUB Order 117/06 gave general approval to the Corporation's Recommended methodology, but also directed Manitoba Hydro to make some specific modifications including:

– Utilizing a single Export Class and allocate costs to that class in a manner comparable to the allocation of cost to domestic classes, plus assign certain costs directly against the class.
– Directly assigning Trading Desk, MAPP and MISO costs, thermal plant costs, water rental and power purchase costs that are directly attributable to export sales to the Export Class.
– Specifically assigning certain other costs to the Export Class, including the revenue impacts of Uniform Rates and the costs of DSM.
– Using 12 SEP time periods in the allocation of Generation-related costs, versus only four as previously recommended by the Corporation.

With the exception of the direction to utilize 12 SEP time periods (which was supported by Manitoba Hydro and has very little impact on the COSS results) the directed changes have a significant impact on the results of the COSS. This is because the directed methodology changes assign a much larger portion of Generation and Transmission costs against exports and reduces the amount of residual export revenues available for allocation to the domestic customer classes.

Manitoba Hydro is also concerned that this approach to cost allocation against export sales is not entirely appropriate, again, because fixed costs of Hydraulic Generation are not incurred to support Opportunity Exports. In the early years of plant in-service new plants may allow for

Opportunity Exports and thereby offset some of their fixed costs, as may all plant during years of higher than normal flows, but these cannot be taken to mean a cost causal relationship.

Treatment of Various Items from Order 117/06 in PCOSS08

PCOSS08 was prepared to comply with the directives in PUB Order 117/06. Significant changes for PCOSS08 include:

a) Generation Costs Allocated on the Basis of Marginal Cost Weighted Energy

PUB Order 117/06 directed Manitoba Hydro to use 12 SEP time periods in the allocation of Generation-related costs versus only four used in the Recommended version of PCOSS06.

The marginal cost weightings are derived from the average (inflation adjusted) Surplus Energy Program ("SEP") rates from the period January 1, 1999 to December 31, 2006. Marginal cost ratios are multiplied by twelve-period seasonal energies (On-Peak, Off-Peak and Shoulder periods for each of the four seasons) which form the basis for allocation of Generation-related costs. The marginal cost ratios applied to seasonal energies in the PCOSS08 are:

	OFF-PEAK	**ON-PEAK**	**SHOULDER**
Winter	1.796	3.406	2.262
Spring	1.246	2.513	2.144
Summer	1.000	3.258	2.388
Fall	1.396	2.624	2.155

b) Export Class

In PUB Order 117/06 Manitoba Hydro was directed to utilize a single Export Class and allocate costs to that class in a manner comparable to the allocation of cost to domestic classes, plus assign certain costs directly against exports. In the Recommended version of PCOSS06 the Corporation had proposed two export classes. Firm Exports would be allocated a share of all Generation and Transmission costs in the same way as domestic classes of service. Opportunity Exports would be assigned only the variable costs associated with these exports: thermal fuel, imports and water rentals. As directed, Manitoba Hydro has utilized a single Export Class in PCOSS08.

c) <u>Definition of Net Export Revenue</u>

In PUB Order 117/06 Manitoba Hydro was directed to directly assign Trading Desk, MAPP and MISO costs, thermal plant costs, water rental and power purchase costs that are directly attributable to export sales to the Export Class. The allocation and/or assignment of these costs in Manitoba Hydro's Recommended Method of PCOSS06 was integrally linked to the existence of two export classes; hence a revised method of allocation and assignment is required to undertake revisions in accordance with PUB Order 117/06.

- Trading Desk, MAPP and MISO costs are directly assigned to the Export Class as an additional cost and are not specifically linked to any energy sales.
- For thermal plant costs, the fuel cost related to operating the thermal plants, $23 million, has been directly assigned to the Export Class. This represents an implied rate of 4.2 cents per kW.h against 560 GW.h of exports. The remaining operating and maintenance costs as well as interest and depreciation expense associated with Thermal Generation is moved into the Generation pool, to be shared by all classes of customer, including exports. Manitoba Hydro believes that this treatment, while not strictly reflecting cost causality, is the closest cost-causal interpretation consistent with the directive. Capital and operating/maintenance costs of Thermal Generation are incurred to provide system reliability, which mostly benefits domestic customers. Fuel costs may be incurred to support either domestic or export sales, but a significant proportion of fuel costs over the longer term is incurred to support domestic sales in low water years. When prices in the export market are sufficiently high, it becomes economic to dispatch thermal stations, but they would not have been built, nor would the ongoing operating and maintenance costs be incurred just to facilitate occasional sales that are economic.
- Power purchase costs and energy are both assigned directly against exports. PCOSS08 forecast 2,028 GW.h of imports, the average cost of which is 4.9 cents per kW.h. Both the costs and the energy have been directly assigned to the Export Class.
- In addition to the assignment or allocation of significant Generation costs to exports, PUB Order 117/06 also directs that certain other costs be specifically assigned to the Export Class: the revenue impacts of Uniform Rates and the costs of DSM for domestic customers. With respect to DSM costs, Manitoba Hydro has interpreted the Order to mean that all DSM energy savings should be assumed to serve the export market. Accordingly, the $25 million in DSM expenses and the associated

1,350 GW.h of annual energy savings associated with all DSM carried out to date are applied to the Export Class. This provided a relatively low cost source of energy (1.8 cents per kW.h) to the Export Class.

– Those exports deemed not to have been served by Thermal Generation, imports or DSM would share remaining Generation pool costs including water rentals on the same basis as domestic customer classes (approximately 3.7 cents per kW.h), even though most of these export sales would be opportunity sales and not backed by the firm resources of the system. Export sales not deemed to have been met out of the specifically identified resources are 4,524 GW.h as shown below:

Total export energy, GW.h	8,462
Less exports served from imports	(2,028)
Less exports served from thermal	(560)
Less DSM savings facilitating exports	(1,350)
Exports served from generation pool, GW.h	4,524

The assignment and allocation of costs as directed in PUB Order 117/06 results in net export revenue of $165 million remaining to be allocated to domestic customers.

Gross Export Revenue	$552 million
Uniform Rates	$17 million
DSM	$25 million
Trading Desk	$13 million
MAPP/MISO/NEB	$7 million
Purchased Power	$134 million
Thermal Costs	$23 million
Allocated G & T (incl. Water rentals)	$167 million
Net Export Revenue	$165 million

d) <u>Allocation of Net Export Revenue</u>

Net export revenues are allocated to customer classes on the basis of total allocated costs of all functions, not just Generation and Transmission costs.

e) <u>Transmission Allocated on Basis of Demand Only</u>

Transmission costs are allocated on the basis of demand only, consistent with direction from PUB Order 117/06, based on the average of summer and winter demands (2 CP)

f) <u>Use of Surplus Energy Program for Marginal Costing</u>

In PCOSS04 when the NERA results were first published, marginal cost indicators were based on commercially available Platt's data for the MISO service area. However, starting with PCOSS06, indicators from Manitoba Hydro's own SEP were used. The advantages are that it is based not only on prices pertaining to sales in the interconnected MAPP market, but also reflects Manitoba Hydro's ability to access those prices and the effect of Transmission constraints on the prices Manitoba Hydro can realize.

g) <u>Direct Assignment of DSM Costs</u>

In PUB Order 117/06 Manitoba Hydro was directed to further reduce net export revenue by the costs of DSM. Consequently, the costs of the DSM initiatives are no longer directly assigned to individual customer classes.

<u>Treatment of Diesel Funding Agreement in PCOSS08</u>

In January 2004 the Public Utilities Board ("PUB") approved significant rate increases to all classes in the diesel rate zone and directed Manitoba Hydro to enter into negotiations with key stakeholders with the goal of securing agreement as to how service costs were to be funded in the future, and how the accumulated deficit would be managed. The key stakeholders were Indian and Northern Affairs Canada (INAC) and Manitoba Keewatinook Ininew Okimowin (MKO).

The terms of the settlement emerging from those negotiations have yet to be finalized but the agreement essentially permits rates to be based on variable cost alone, with capital costs being largely funded through contributions by INAC (through the four communities) and other federal and provincial government agencies with accounts in these communities. The agreement also promises an allocation of net export revenue to support service in the Diesel communities; it is first to be applied to amortize the accumulated deficit, and then it will be available to reduce current cost of service.

As allocation of export revenues are, as provided in the agreement, based on total cost to serve in the diesel rate zone, that total cost is reflected in the RCC Table in PCOSS08. Revenues for the Diesel class in the schedules are based upon variable costs, upon which the revised diesel rates are based. As a result the RCC in the PCOSS does not reflect the true RCC of the Diesel class.

The RCC calculated using the Diesel Cost of Service Study for 2006/07, upon which interim *ex parte* rates from PUB Order 176/06 are based, is 86.3% using revenues of $4,512,711 and variable costs of $5,226,151. Note that revenue does not include allocated net export revenues, which are currently being applied against the accumulated deficit.

An updated Diesel COSS will be prepared upon finalization of the funding agreement.

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SECTION B

SUMMARY RESULTS

The Revenue Cost Coverage ("RCC") results of the PCOSS08 are shown for two scenarios: PUB Order 117/06 Method and Retained Earnings Deficiency Method.

The Retained Earnings Deficiency Method results are displayed to illustrate the effects on RCCs of the current deficiency in retained earnings relative to the target 75:25 debt/equity ratio. That is, because retained earnings are deficient by approximately $342 million relative to the target, it is reasonable that RCC's should reflect this deficiency. The results of this scenario illustrate the need for steady, measured rate increases over time in order for the Corporation to meet its financial targets. As rate increases are implemented and retained earnings increase, RCCs will increase correspondingly.

As has been typical of past PCOSS, the study has been prepared on the basis of a financial forecast incorporating median water flows, specifically, on the basis of IFF06-3. The level of export earnings forecast in this PCOSS reflects this assumption. Since the final preparation of the PCOSS08, IFF06-3 has since been revised and denoted as IFF06-04. The primary differences between the two forecasts is the proposed 2.9% rate increase for April 1, 2008 as well as updated water flow conditions. The PCOSS08 filed herein is based on IFF06-3 with the rate increase of 2.5% proposed for August 1, 2007 removed from revenue. IFF06-3 is based on median flows, which are typically the basis of Manitoba Hydro's PCOSS. Median flows are best represented in the COSS as rate setting should be based on expected values and not based on the variability of hydraulic conditions which may or may not occur.

This Section outlines the three primary tables of both of these scenarios: Revenue Cost Coverage ("RCC"), Customer, Demand and Energy ("CDE"), and Functional Cost Analysis. Schedules B1 through B3 outline the summary results from PCOSS08 based on the methodology directed in PUB Order 117/06. Subsequent Schedules, B4 through B6 outline the same schedules using the Retained Earnings Deficiency Method.

1. Revenue Cost Coverage Tables – This ratio compares revenues of each class to its allocated costs. The RCC ratio provides the relative performance of each rate class over a base of 100%. Schedules B1 and B4 outline the customer class RCC;

2. Customer, Demand and Energy Costs (“CDE”) – In this table the components are converted to unit costs using billing determinants, i.e., number of customers, billable demand and kW.h sales. The information in Schedules B2 and B5 is intended to provide a comparison of allocated unit costs with the corresponding price in the appropriate rate schedule; and

3. Functional Breakdown – This table identifies the cost of providing each level of service to each customer class. This information could be beneficial when evaluating service extension policies or construction allowance guidelines. Schedules B3 and B6 outline the functional breakdown.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2008
Revenue Cost Coverage Analysis
MH Model of 117/06 Directives
S U M M A R Y

Customer Class	(1) Total Cost w/o Consideration of Exports [1] ($000)	(2) Class Revenue ($000)	(3) RCC % Assuming No Exports (2 ÷ 1)	(4) Reallocation of Costs to Exports Re: 117/06 ($000)	(5) Net Export Revenue Re: 117/06 ($000)	(6) Total Revenue ($000) (2 + 5)	(7) Total Cost ($000) (1 + 4)	(8) RCC % March 2007 Rates (6 ÷ 7)
Residential	582,361	433,136	74.4%	(60,345)	70,102	503,238	522,016	96.4%
General Service - Small Non Demand	117,534	92,895	79.0%	(15,254)	13,735	106,630	102,279	104.3%
General Service - Small Demand	140,341	112,162	79.9%	(20,777)	16,056	128,218	119,564	107.2%
General Service - Medium	193,822	144,186	74.4%	(29,322)	22,091	166,277	164,500	101.1%
General Service - Large 0 - 30kV	101,326	65,925	65.1%	(15,626)	11,509	77,434	85,700	90.4%
General Service - Large 30-100kV*	47,694	35,367	74.2%	(8,431)	5,349	40,716	39,262	103.7%
General Service - Large >100kV*	218,168	164,004	75.2%	(45,226)	24,017	188,021	172,941	108.7%
*Includes Curtailment Customers								
SEP	1,751	1,561	89.1%	-	-	1,561	1,751	89.1%
Area & Roadway Lighting	19,650	19,243	97.9%	(620)	892	20,135	19,031	105.8%
Total General Consumers	1,422,647	1,068,480	75.1%	(195,602)	163,750	1,232,231	1,227,045	100.4%
Diesel [2]	11,495	4,765	41.5%	-	1,544	6,309	11,495	54.9%
Export	190,614	551,510		195,602	(165,294)	386,216	386,216	100.0%
Total System	1,624,755	1,624,755	100.0%	-	-	1,624,755	1,624,755	100.0%

[1] **This initial allocation of costs assumes no exports and therefore all costs not variable with exports are allocated to domestic customers.** Variable costs associated with exports, therefore, have been withdrawn from the Generation and Transmission cost pool allocated to Domestic customers. Variable costs directly attributable to exports include Water Rentals ($21 million), NEB/MAPP/MISO ($6 million), Thermal Fuel ($12 million), and Power Purchases ($134 million). The Uniform Rates adjustment of $17 million is also removed from the initial pool assigned to domestic customers.

[2] Diesel cost and RCC do not reflect Contributions received under the funding agreement. See discussion of *Treatment of Funding Agreement in PCOSS08* in Section A

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Customer, Demand, Energy Cost Analysis
MH Model of 117/06 Directives
SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy mWh	ENERGY Unit Cost ¢/kWh
Residential	102,330	455,903	18.70	172,761	0%	n/a	n/a	176,823	6,577,526	5.31 **
GS Small - Non Demand	19,517	52,042	31.25	32,933	0%	n/a	n/a	36,094	1,328,832	5.19 **
GS Small - Demand	5,684	9,248	51.22	43,765	34%	2,124	6.99	54,058	2,038,415	4.07
General Service - Medium	4,923	1,801	227.78	59,506	100%	8,042	7.40	77,980	2,948,717	2.64
General Service - Large <30kV	2,407	252	n/a	29,820	100%	3,826	8.42 *	41,965	1,611,803	2.60
General Service - Large 30-100kV	1,395	28	n/a	8,240	100%	2,104	4.58 *	24,278	987,630	2.46
General Service - Large >100kV	1,707	14	n/a	21,258	100%	8,597	2.67 *	125,960	5,202,246	2.42
SEP	357	28	1,062.24	296	0%	n/a	n/a	1,099	23,700	5.88 **
Area & Roadway Lighting	13,694	150,000	7.61	2,361	0%	n/a	n/a	2,084	95,997	4.63 **
Total	152,015	669,316		370,939		24,693		540,340	20,814,867	

* - includes recovery of customer costs
** - includes recovery of demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Functional Breakdown
MH Model of 117/06 Directives
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	451,914	176,823	39.1%	42,866	9.5%	33,332	7.4%	47,670	10.5%	151,223	33.5%
General Service - Small Non Demand	88,544	36,094	40.8%	10,193	11.5%	5,857	6.6%	12,287	13.9%	24,113	27.2%
General Service - Small Demand	103,507	54,058	52.2%	13,826	13.4%	7,683	7.4%	2,482	2.4%	25,459	24.6%
General Service - Medium	142,409	77,980	54.8%	19,897	14.0%	10,164	7.1%	3,986	2.8%	30,382	21.3%
General Service - Large <30kV	74,192	41,965	56.6%	10,694	14.4%	5,553	7.5%	2,189	3.0%	13,790	18.6%
General Service - Large 30-100kV	33,913	23,710	69.9%	5,567	16.4%	3,241	9.6%	1,350	4.0%	46	0.1%
General Service - Large >100kV	148,925	120,060	80.6%	27,158	18.2%	0	0.0%	1,683	1.1%	24	0.0%
SEP	1,751	1,099	62.7%	296	16.9%	0	0.0%	338	19.3%	19	1.1%
Area & Roadway Lighting	18,139	2,294	12.6%	401	2.2%	564	3.1%	542	3.0%	14,338	79.0%
Total General Consumers	1,063,294	534,083	50.2%	130,899	12.3%	66,394	6.2%	72,526	6.8%	259,393	24.4%

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2008
Revenue Cost Coverage Analysis
Retained Earnings Deficiency
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	640,467	433,136	67.6%	48,493	481,630	75.2%
General Service - Small Non Demand	124,637	92,895	74.5%	9,437	102,332	82.1%
General Service - Small Demand	148,845	112,162	75.4%	11,270	123,431	82.9%
General Service - Medium	204,808	144,186	70.4%	15,507	159,693	78.0%
General Service - Large 0 - 30kV	106,737	65,925	61.8%	8,082	74,007	69.3%
General Service - Large 30-100kV*	49,145	35,367	72.0%	3,764	39,131	79.6%
General Service - Large >100kV*	218,977	164,004	74.9%	17,027	181,031	82.7%
*Includes Curtailment Customers						
SEP	1,759	1,561	88.8%	-	1,561	88.8%
Area & Roadway Lighting	22,462	19,243	85.7%	618	19,861	88.4%
Total General Consumers	1,517,836	1,068,480	70.4%	114,197	1,182,677	77.9%
Diesel [1]	12,557	4,765	37.9%	951	5,716	45.5%
Export	436,362	551,510	126.4%	(115,148)	436,362	100.0%
Total System	1,966,755	1,624,755	82.6%	-	1,624,755	82.6%

[1] Diesel cost and RCC do not reflect Contributions received under the funding agreement. See discussion of *Treatment of Funding Agreement in PCOSS08* in Section A

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Customer, Demand, Energy Cost Analysis
Retained Earnings Deficiency
SUMMARY

	CUSTOMER			DEMAND				ENERGY		
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh
Residential	125,458	455,903	22.93	228,146	0%	n/a	n/a	238,369	6,577,526	7.09 **
GS Small - Non Demand	23,019	52,042	36.86	43,524	0%	n/a	n/a	48,657	1,328,832	6.94 **
GS Small - Demand	6,857	9,248	61.79	57,845	34%	2,124	9.24	72,873	2,038,415	5.45
General Service - Medium	5,511	1,801	254.98	78,668	100%	8,042	9.78	105,122	2,948,717	3.57
General Service - Large <30kV	2,630	252	n/a	39,454	100%	3,826	11.00 *	56,571	1,611,803	3.51
General Service - Large 30-100kV	1,517	28	n/a	11,135	100%	2,104	6.01 *	32,729	987,630	3.31
General Service - Large >100kV	1,847	14	n/a	30,301	100%	8,597	3.74 *	169,801	5,202,246	3.26
SEP	364	28	1,083.89	292	0%	n/a	n/a	1,102	23,700	5.88 **
Area & Roadway Lighting	15,921	150,000	8.85	3,114	0%	n/a	n/a	2,809	95,997	6.17 **
Total	183,124	669,316		492,480		24,693		728,034	20,814,867	

* - includes recovery of customer costs
** - includes recovery of demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Functional Breakdown
Retained Earnings Deficiency
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	591,974	238,369	40.3%	57,139	9.7%	44,046	7.4%	51,475	8.7%	200,945	33.9%
General Service - Small Non Demand	115,200	48,657	42.2%	13,587	11.8%	7,739	6.7%	13,263	11.5%	31,954	27.7%
General Service - Small Demand	137,575	72,873	53.0%	18,430	13.4%	10,152	7.4%	2,680	1.9%	33,440	24.3%
General Service - Medium	189,301	105,122	55.5%	26,522	14.0%	13,431	7.1%	4,301	2.3%	39,924	21.1%
General Service - Large <30kV	98,656	56,571	57.3%	14,255	14.4%	7,339	7.4%	2,362	2.4%	18,129	18.4%
General Service - Large 30-100kV	45,381	32,160	70.9%	7,421	16.4%	4,283	9.4%	1,456	3.2%	61	0.1%
General Service - Large >100kV	201,950	163,902	81.2%	36,201	17.9%	0	0.0%	1,816	0.9%	31	0.0%
SEP	1,759	1,102	62.7%	292	16.6%	0	0.0%	341	19.4%	23	1.3%
Area & Roadway Lighting	21,845	2,956	13.5%	510	2.3%	713	3.3%	559	2.6%	17,107	78.3%
Total General Consumers	1,403,639	721,713	51.4%	174,358	12.4%	87,702	6.2%	78,252	5.6%	341,613	24.3%

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SECTION C

FUNCTIONALIZATION AND CLASSIFICATION METHODS AND DETAILS

Organization and Preparation of Forecast Data

This Section provides a basic review of the approaches taken to organize Manitoba Hydro's 2007/08 forecast data for use in the PCOSS and the functionalization and classification of costs in preparation for allocation to customer classes. Allocation methods are explained in Section D. The remainder of this Section is organized as follows:

– Definitions
– Functionalization and Classification Process
– Functionalization and Classification of Capital Related Costs
– Functionalization and Classification of Operating and Administrative Costs
– Adjusted Revenue

Definitions

Functionalization – Functionalization is the preliminary arrangement of cost according to functions performed by the electric system. Manitoba Hydro has defined its functional levels as follows:

1. Generation Function – This function includes all generating facilities, HVDC facilities (excluding Dorsey Converter Station), communication facilities associated with the Generation function and a share of the administration buildings and general equipment.

2. Transmission Function – Historically Transmission facilities have included the high voltage (100 kV and higher) grid transmission lines. With the methodology changes introduced in the PCOSS02, this has been further refined to include only transmission lines which would be recognized for inclusion in Manitoba Hydro's Open Access Transmission Tariff. Radial Transmission facilities, including those with voltage greater than 100 kV, are included in the Subtransmission function. In addition to the transmission lines above, this function also includes: Dorsey Converter Station, the high voltage portion of substations, the communications facilities associated with the Transmission function and a share of the administration buildings, general equipment and substation transformers in stock.

3. Ancillary Services Function – This function includes specific items[1] previously bundled in the Generation or Transmission function. Ancillary Services are services necessary to support the Transmission of capacity and energy from resources (Transmission provider) to load while maintaining reliable operation of the Transmission provider's electrical system. A complete description of the ancillary services offered can be found in the "Functionalization and Classification of Capital Related Costs" Section that follows.

4. Subtransmission Function – This function includes non grid/radial transmission lines (greater than 100 kV), lower voltage (66 kV and 33 kV) subtransmission lines, the low voltage portion of the substations and a share of communication equipment, administration buildings, general equipment and substation transformers in stock. These facilities are required to bring the power from the common bus network to specific load centres.

5. Distribution Plant Function – This function includes the low voltage (less than 33 kV) distribution lines, the low voltage portion of the substations, meters, metering transformers, distribution transformers and a share of communication equipment, administration buildings, general equipment and substation transformers in stock.

6. Distribution (or Customer) Services Function – This function captures all costs associated with serving the customer after delivery of the energy. This includes such costs as billing and collections, as well as other departmental costs such as Power Smart Energy Services and Rates & Regulatory. In addition, it includes a share of administration buildings and general equipment associated with these activities.

Classification – All functionalized costs are classified into one or more of the following: Demand, Energy and Customer-related cost components for allocation to the classes of service. This process also enables the determination of unit demand, energy and customer costs for each customer class.

1. Class of Service – A group of customers having reasonably similar service characteristics, plant facilities requirements, ultimate energy use and load patterns.

[1] As based on Business Process Synchronization Unit ("BPSU") breakdown in SAP.

2. Cost Component – The term used to describe the classification of an electric utility's total operating expenses and capital investment in electric plant as Demand, Energy or Customer-related costs.

3. Customer Costs – Customer costs are costs associated with the carrying of customers on the power system, or the addition of customers to the power system.

4. Energy Costs – Energy costs are costs associated with the consumption of electricity over a period of time by customers of the power system.

5. Demand Costs – Demand costs are costs associated with the rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers.

6. Load Factor – Load Factor is an expression of the proportion of time that a utility, a class of service or an individual customer is utilizing the facilities installed to provide service. It is expressed as a ratio or percentage relating energy kilowatt-hours (kW.h) to the maximum demand requirements (kW) during a specified time period.

Functionalization and Classification Process

Manitoba Hydro's COSS has been developed with reference to industry standards as well as the design and operating characteristics of its electric system. Manitoba Hydro functionalizes gross and net plant in-service for the purpose of functionalizing interest expense, capital tax, as well as the contributions to or appropriations from reserves. Manitoba Hydro does not perform a traditional allocation of rate base as a rate of return is not measured, but reserve additions required to achieve reasonable financial targets are included as a cost of service. Revenue to cost ratios are used to aid in the evaluation of rate levels.

Functionalization and Classification of Capital Related Costs

In the preparation of the PCOSS the base year gross investment, that being actual plant in-service as of March 31, 2006, is first functionalized.

Functionalized gross plant investment for 2006 is set forth in Schedule C1. Plant investment is functionalized into the following areas:

- Generation
- Transmission (Domestic, Export)
- Ancillary Service
- Subtransmission
- Distribution Plant
- Distribution Services

Substations are functionalized recognizing Alternating Current ("AC") and Direct Current ("DC") facilities. All DC substations (with the exception of Dorsey Station which is functionalized as Transmission) are functionalized as Generation. AC substations are analyzed and functionalized as Transmission, Subtransmission and Distribution. This analysis includes a review of voltage levels, functions, current use and related books and records of the company. Transmission lines and related facilities are functionalized on a comparable basis including analysis of voltage level, current use and function. The Transmission function is separated into facilities used solely by domestic consumers and into facilities used to interconnect Manitoba Hydro's central transmission grid with neighbouring utilities.

There are six types of Ancillary Services, all of which must be offered by the Transmission provider. Of these six services, the purchaser of this service must purchase two (1 and 2 below) from the Transmission provider. The remaining four other Ancillary Services can be procured from the service provider, self supplied, or purchased from a third party.

A brief description of each of the six Ancillary Services is outlined below:

1. Scheduling, System Control and Dispatch Service – Required to schedule the movement of power from, to or within a control area.

2. Reactive Supply and Voltage Control from Generation Source Service – Required to maintain Transmission voltages within acceptable limits.

3. Regulation and Frequency Response Service – Required to provide for the continuous balance of resources (Generation and Transmission) with load and maintaining scheduled interconnections at sixty cycles per second.

4. Energy Imbalance Service – Provided when differences occur between scheduled and actual delivery of energy to a load over a single hour.

5. Operating Reserve – Spinning Service – Needed to serve load immediately in the event of a system contingency.

6. Operating Reserve – Supplemental Reserve Service – Same as spinning reserve, but able to serve load within a short period of time.

As noted previously Ancillary Services are items previously bundled within the Generation and Transmission function. Separation of these components is done through analysis of individual Generation and Transmission asset components. Classification of Ancillary Services is the same as Transmission costs.

All Distribution facilities, farm lines, meters and metering transformers are functionalized as Distribution. Subtransmission facilities are analyzed by voltage level and functionalized accordingly.

Communication equipment is functionalized to Generation, Transmission, Subtransmission and Distribution plant. The communication equipment associated with the above functions is based upon the investment in these facilities.

Buildings and other administrative facilities are treated as administration cost centres in the Financial Reporting System ("SAP"). These non-facility cost centres, as they are called in SAP, are allocated back to facility cost centres based on specific assessment cycles within the system. These assessments bring facility cost centres to full cost which can then be appropriately functionalized.

The forecast of capital additions consists of major item additions and domestic item additions. The domestic items consist of non-blanket items (facilities identified) and blanket items (facilities broadly identified). Capital items consist of gross additions, salvage material and capital contributions. The functionalization of the entries that result from the forecast for salvage material and capital contributions is treated consistently with the functionalization of gross additions with one exception - the assignment of capital contributions for the Diesel Rate Zone. These contributions are deducted from those functionalized to distribution lines, as contributions in the Diesel Zone are received primarily through work undertaken on district work orders.

Major item additions are functionalized based on the facility being constructed and included in the COS once the new asset is placed in service. Whereas functionalization of domestic items is based on a three-year average of previous domestic item expenditures since the facilities are only broadly defined.

Included in the forecast of capital additions is salvage labour and expense which must be backed out of the forecast additions to arrive at gross investment. The financial forecast assumes salvage labour and expense at 51% of the salvage material value and the historic cost of facilities being retired at 153% of the salvage material value. The COSS replicates this process. Salvage labour and expense affects the forecast of accumulated depreciation and historic retirement values reduce both gross investment and accumulated depreciation. Schedule C2 details the functionalized gross investment forecast for the fiscal year ending March 31, 2008.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year end to March 31, 2008. Accumulated depreciation for diesel generation, street lighting (asset class distribution lines and farm lines), HVDC (asset class substation and transmission lines) and export (asset class substation and transmission lines) are assigned. For the remaining functional costs, accumulated depreciation by asset class is prorated based upon functionalized gross investment (opening balance).

The customer contributions are shown in Schedules C4 and C5. Unamortized customer contributions can be found in Schedule C4; whereas Schedule C5 details the functionalization of customer contribution amortization. Schedule C6 outlines the functionalized net depreciation expense. Schedule C7 shows the net investment for fiscal year end 2008.

Depreciation expense, both direct facility depreciation and allocated administrative depreciation, is separated from operating costs. The Corporation periodically undertakes a depreciation study (every five years) to ensure that amortization of assets is commensurate with the actual life of a particular asset. The last such review was in fiscal year 2004/05, these revised rates are reflected in the PCOSS08. Functionalized depreciation expense is also matched and adjusted to reflect amortization of customer contributions.

Schedule C8 outlines Rate Base Investment which is used to functionalize net interest expense as well as the forecasted contribution to reserves. The rate base is the average of the net plant in-service forecast for fiscal years 2006/07 and 2007/08 with adjustments for net deferred assets (calculation of the average investment can be found in Schedule C15). Schedule C9 follows with the functionalized net interest and reserve contribution.

Schedule C10 shows the functionalization of rate base for capital tax at March 31, 2008 (gross investment less accumulated depreciation) adjusted to include net deferred expenses which is used to functionalize forecast capital tax assessment. The functionalization of the forecasted capital tax assessment for 2007/08 is shown on Schedule C11.

Functionalization and Classification of Operating and Administrative Costs

The PCOSS is based on revenue and cost data contained in the Corporation's Integrated Financial Forecast ("IFF"), supplemented with the use of Manitoba Hydro's Financial Reporting System, SAP.

Schedule C12 outlines operating costs by function and sub-functions.

As with net depreciation expense, these values are determined from the Financial Reporting System (SAP) and include allocations for administrative costs. SAP, via settlement cost centres, provides the initial functionalization of all functional operating and maintenance costs as well as depreciation expense. Final functionalization is done off-line and includes functionalization of items such as communication system costs to all functions except customer service. Other off-line changes made include classification of distribution costs into customer and demand components. This approach used to classify distribution facilities are common to regulatory practices elsewhere. The demand/customer split by component is summarized below:

	COST CLASSIFICATION	
DISTRIBUTION FACILITIES	**DEMAND**	**CUSTOMER**
Substation	100%	
Line Transformers	100%	
Pole, Wire and Related Facilities	60%	40%
Meters and Metering Transformers		100%
Services		100%

Adjusted Revenue

Schedule C13 details class revenue and the allocation of adjustments to arrive at class/subclass revenue contained in the PCOSS. Unadjusted revenue by rate class/subclass is taken from the Proof of Revenue calculation. The revenue reduction associated with DSM Programs is also assigned to the customer rate classes in the general consumers revenue forecast process.

DSM revenue reduction by class is shown below:

	TOTAL
Residential	$ 2,434,116
General Service Small-Non-Demand	$ 1,499,057
General Service Small-Demand	$ 1,289,248
General Service Medium	$ 1,658,492
General Service Large:	
0 - 30 kV	$ 962,202
30 - 100 kV	$ 96,212
> 100 kV	$ 341,285
Total DSM	**$8,280,612**

The accrual adjustment represents any forecasted increase in either sales or rates over the previous accrual amounts. This adjustment is allocated to the rate classes/subclasses excluding seasonal, large power customers and street lighting. No seasonal accrual is forecast for street lights and large power customers that are billed at month end and therefore no accrual is required.

The general consumer's adjustment which is comprised primarily of late payment charges and some customer adjustments which are not identified to a specific rate class, is also allocated based upon unadjusted revenue excluding large power customers. Although some of this revenue would apply to the large power customer it would be minimal and clearly disproportional to sales.

Reconciliation of revenue in the IFF to that in the Cost of Service is shown on Schedule C14.

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
MARCH 31, 2006

Asset Class	Total	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	4,797,362,478	4,751,335,572	46,026,906							
DIESEL	40,356,844	569,069								39,787,775
SUBSTATION	936,968,871		273,418,660	48,243,054	148,973,364	454,534,769		11,799,024		
- HVDC	1,142,749,848	560,746,214	582,003,634							
TRANSMISSION	559,271,157		266,329,484	116,790,577	176,151,096					
- HVDC	186,055,962	186,055,962								
DISTRIBUTION	1,681,320,216					1,552,247,629			125,059,132	4,013,455
SUBTRANSMISSION	229,529,573				219,092,585	10,436,988				
TRANSFORMERS										
- SUBSTATION	13,617,303		4,024,433	710,087	2,192,730	6,690,054				
- DISTRIBUTION	4,546,423					4,546,423				
METERS	40,609,680					40,609,680				
METERING TRANSFORMERS	6,082,405					6,082,405				
BUILDINGS	176,564,542	76,221,395	18,102,389	7,951,703	12,269,258	40,192,036	16,355,583		4,849,701	622,477
COMMUNICATION	337,072,260	78,213,694	30,002,506	9,698,882	67,962,402	77,507,695		73,687,081		
GENERAL EQUIPMENT	306,971,700	88,681,340	38,285,070	16,815,235	25,954,535	81,944,804	45,363,690		9,883,010	44,016
SUBTOTAL	10,459,079,262	5,741,823,246	1,258,193,081	200,209,538	652,595,970	2,274,792,483	61,719,273	85,486,105	139,791,843	44,467,723
MOTOR VEHICLES	127,714,868									
TOTAL FIXED ASSETS	10,586,794,130	5,741,823,246	1,258,193,081	200,209,538	652,595,970	2,274,792,483	61,719,273	85,486,105	139,791,843	44,467,723

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2008

			Transmission		Sub-	Distribution		Ancillary	Direct Allocation	
Asset Class	Total	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	4,965,359,496	4,919,332,590	46,026,906	-	-	-	-	-	-	-
DIESEL	41,152,059	569,069	-	-	-	-	-	-	-	40,582,990
SUBSTATION	1,035,103,544	-	294,965,181	62,304,147	162,745,333	503,289,859	-	11,799,024	-	-
- HVDC	1,221,796,343	597,148,573	624,647,770	-	-	-	-	-	-	-
TRANSMISSION	601,034,868	-	300,105,899	122,406,890	178,522,079	-	-	-	-	-
- HVDC	186,625,721	186,625,721	-	-	-	-	-	-	-	-
DISTRIBUTION	1,863,422,787	-	-	-	-	1,731,358,181	-	-	128,012,572	4,052,034
SUBTRANSMISSION	282,032,681	-	-	-	270,122,078	11,910,603	-	-	-	-
TRANSFORMERS										
- SUBSTATION	16,174,358	-	4,024,433	710,087	2,192,730	9,247,109	-	-	-	-
- DISTRIBUTION	4,546,423	-	-	-	-	4,546,423	-	-	-	-
METERS	47,271,432	-	-	-	-	47,271,432	-	-	-	-
METERING TRANSFORMERS	6,082,405	-	-	-	-	6,082,405	-	-	-	-
BUILDINGS	453,033,104	195,992,750	46,547,784	20,446,702	31,548,696	103,348,248	42,056,114		12,470,334	622,477
COMMUNICATION	392,043,092	84,243,230	73,390,105	9,727,842	69,231,066	81,763,768	-	73,687,081	-	-
GENERAL EQUIPMENT	403,356,664	116,530,075	50,307,788	22,095,749	34,105,077	107,678,055	59,609,318		12,986,587	44,016
SUBTOTAL	11,519,034,977	6,100,442,007	1,440,015,866	237,691,416	748,467,059	2,606,496,082	101,665,432	85,486,105	153,469,492	45,301,517
MOTOR VEHICLES	173,298,283									
TOTAL FIXED ASSETS	11,692,333,260	6,100,442,007	1,440,015,866	237,691,416	748,467,059	2,606,496,082	101,665,432	85,486,105	153,469,492	45,301,517

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF ACCUMULATED DEPRECIATION
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Accum Depn by Asset Class	Generation	Transmission Domestic	Transmission Export	Sub Trans	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocation Lighting	Direct Allocation Diesel
GENERATION	1,629,857,587	1,613,508,363	16,349,224	-	-	-	-	-	-	-
DIESEL	25,508,704	235,626	-	-	-	-	-	-	-	25,273,078
SUBSTATION	378,671,858	-	105,850,144	18,264,596	77,780,210	167,233,587	-	9,543,321	-	-
- HVDC	581,286,017	310,370,125	270,915,892	-	-	-	-	-	-	-
TRANSMISSION	185,272,861	-	99,293,190	43,851,346	42,128,325	-	-	-	-	-
- HVDC	65,560,231	65,560,231	-	-	-	-	-	-	-	-
DISTRIBUTION	775,352,615	-	-	-	-	705,113,443	-	-	68,090,226	2,148,946
SUBTRANSMISSION	81,784,106	-	-	-	78,366,991	3,417,114	-	-	-	-
TRANSFORMERS										
- SUBSTATION	5,718,628	-	1,637,154	282,548	1,200,161	2,598,765	-	-	-	-
- DISTRIBUTION	1,579,505	-	-	-	-	1,579,505	-	-	-	-
METERS	15,799,862	-	-	-	-	15,799,862	-	-	-	-
METERING TRANSFORMERS	2,793,035	-	-	-	-	2,793,035	-	-	-	-
BUILDINGS	38,584,275	15,449,172	4,210,941	1,849,709	2,853,652	9,472,888	3,457,890		1,143,757	146,267
COMMUNICATION	143,576,442	39,137,687	10,803,030	3,014,711	26,225,865	24,020,625	-	40,374,526	-	-
GENERAL EQUIPMENT	185,451,711	55,726,290	24,396,661	10,715,996	16,535,450	48,830,289	23,313,256		5,889,753	44,016
SUBTOTAL	4,116,797,437	2,099,987,493	533,456,235	77,978,906	245,090,653	980,859,113	26,771,146	49,917,846	75,123,736	27,612,307
MOTOR VEHICLES	62,440,961									
TOTAL ACCUM DEPRECIATION	4,179,238,398	2,099,987,493	533,456,235	77,978,906	245,090,653	980,859,113	26,771,146	49,917,846	75,123,736	27,612,307

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
UNAMORTIZED BALANCE
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Unamortized Capital Contribution	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	10,490	10,490	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-
SUBSTATION	33,075,734	-	3,328,234	4,957,445	24,701,333	88,723	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
TRANSMISSION	70,373,768	-	7,650,523	-	62,723,245	-	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
DISTRIBUTION	150,211,956	-	-	-	-	123,870,567	-	-	25,891,908	449,481
SUBTRANSMISSION	14,443,421	-	-	-	14,240,397	203,024	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	8,313	-	-	-	-	8,313	-	-	-	-
METERING TRANSFORMERS	-	-	-	-	-	-	-	-	-	-
BUILDINGS	-	-	-	-	-	-	-	-	-	-
COMMUNICATION	13,887	-	-	-	13,887	-	-	-	-	-
GENERAL EQUIPMENT	5,089	5,089	-	-	-	-	-	-	-	-
SUBTOTAL	268,142,658	15,579	10,978,757	4,957,445	101,678,862	124,170,626	-	-	25,891,908	449,481
MOTOR VEHICLES	-									
TOTAL UNAMORTIZED CONTRII	268,142,658	15,579	10,978,757	4,957,445	101,678,862	124,170,626	-	-	25,891,908	449,481

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
ANNUAL AMORITIZATION
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Annual Amortization Contribution	Generation	Transmission Domestic	Transmission Export	Sub - Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocation Lighting	Direct Allocation Diesel
GENERATION	823	823								
DIESEL	-	-								
SUBSTATION	1,512,624		128,251	340,665	1,038,175	5,534				
- HVDC	-									
TRANSMISSION	2,257,279		583,681		1,673,598					
- HVDC	-									
DISTRIBUTION	7,899,070					6,049,451			1,814,556	35,064
SUBTRANSMISSION	787,738				787,738					
TRANSFORMERS										
- SUBSTATION	-									
- DISTRIBUTION	-									
METERS	-									
METERING TRANSFORMERS	-									
BUILDINGS	-									
COMMUNICATION	27,757				27,757					
GENERAL EQUIPMENT	-									
SUBTOTAL	12,485,291	823	711,933	340,665	3,527,266	6,054,985	-	-	1,814,556	35,064
MOTOR VEHICLES	-									
TOTAL ANNUAL AMORT.	12,485,291	823	711,933	340,665	3,527,266	6,054,985	-	-	1,814,556	35,064

2008 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2008
Functionalization of Depreciation Costs

Description	Depreciation	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Generation External Marketing	173,281	-								173,281
Common Generation Costs	17,023,386	4,888,850					-			12,134,536
Generating Station Costs	11,227,031	11,227,031					-			-
Other Generation Related Costs	180,247	180,247								
Dedicated Gen. Facilities	11,407,277	11,407,277					-	-	-	-
Hydraulic Generating Stations	45,313,520	45,313,520					-			
Other Hydraulic Generation Related Costs	14,283,309	14,283,309					-			
Hydraulic Generation Costs	59,596,829	59,596,829					-			
Thermal Generating Station	17,473,982	17,473,982					-	-	-	-
Non-Dedicated Gen. Facilities	77,070,812	77,070,812					-			-
Generation Facilities Costs	88,478,089	88,478,089					-			-
Purchased Power/Export Costs	-	-								-
Generation Facilities & Costs	***105,501,475***	***93,366,940***					***-***			***12,134,536***
Transmission External Marketing	69,774	-	-	-						69,774
Common Trans. Costs/Revenues	3,812,530	35,318	3,024,590	682,848			-			69,774
Generation Switching Stations	2,415,023	-	2,415,023							
HVDC & Collector Facilities	55,966,480	26,445,521	29,520,959							
Networked AC Facilities	8,535,964	-	8,535,964							
Generation Access Transmission	66,917,468	26,445,521	40,471,946							
Regional Networked Trans.	7,789,953	-	7,684,992				104,961			
Future Transmission Line ROW	11,615	-	11,615							
Transmission Facilities/Costs	***80,012,100***	***26,480,839***	***52,674,736***	***679,088***			***107,663***			***69,774***
Common Subtransmission Costs	767,983	-	-	767,983						
Subtrans. Facilities & Costs	***18,879,710***	***-***	***-***	***15,838,558***	***3,041,152***	***-***	***-***	***-***	***-***	***-***
Dist. Facilities & Costs	***87,344,666***	***-***	***-***	***-***	***85,146,948***	***288,084***		***-***	***1,909,634***	***-***
Customer Service Costs	***9,368,744***	***-***	***-***	***-***	***-***	***9,368,744***		***-***	***-***	***-***
Isolated Diesel Facilities	***7,297,873***	***1,453,115***	***-***	***-***	***1,284,625***	***-***	***-***	***4,560,133***		
Communication & Control System	***15,066,081***	***4,435,820***	***1,661,903***	***2,779,564***	***3,700,337***	***-***	***2,488,456***	***-***	***-***	***-***
	323,470,650	**125,736,714**	**54,336,639**	**19,297,210**	**93,173,062**	**9,656,828**	**2,596,119**	**4,560,133**	**1,909,634**	**12,204,310**

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF NET INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Net Investment	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocation Lighting	Direct Allocation Diesel
GENERATION	3,335,491,419	3,305,813,737	29,677,682	-	-	-	-	-	-	-
DIESEL	15,643,355	333,443	-	-	-	-	-	-	-	15,309,912
SUBSTATION	623,355,952	-	185,786,803	39,082,105	60,263,791	335,967,549	-	2,255,703	-	-
- HVDC	640,510,326	286,778,448	353,731,878	-	-	-	-	-	-	-
TRANSMISSION	345,388,239	-	193,162,186	78,555,544	73,670,509	-	-	-	-	-
- HVDC	121,065,490	121,065,490	-	-						
DISTRIBUTION	937,858,217	-	-	-	-	902,374,171	-	-	34,030,439	1,453,607
SUBTRANSMISSION	185,805,154	-	-	-	177,514,689	8,290,465	-	-	-	-
TRANSFORMERS										
- SUBSTATION	10,455,730	-	2,387,278	427,538	992,569	6,648,345	-	-	-	-
- DISTRIBUTION	2,966,918	-	-	-	-	2,966,918	-	-	-	-
METERS	31,463,257	-	-	-	-	31,463,257	-	-	-	-
METERING TRANSFORMERS	3,289,370	-	-	-	-	3,289,370	-	-	-	-
BUILDINGS	414,448,829	180,543,578	42,336,843	18,596,993	28,695,044	93,875,361	38,598,224	-	11,326,576	476,210
COMMUNICATION	248,452,763	45,105,543	62,587,076	6,713,132	42,991,315	57,743,142	-	33,312,555	-	-
GENERAL EQUIPMENT	217,899,864	60,798,695	25,911,128	11,379,752	17,569,627	58,847,766	36,296,062	-	7,096,834	-
SUBTOTAL	7,134,094,881	4,000,438,934	895,580,874	154,755,064	401,697,544	1,501,466,342	74,894,286	35,568,259	52,453,849	17,239,729
MOTOR VEHICLES	110,857,323									
TOTAL NET INVESTMENT	7,244,952,204	4,000,438,934	895,580,874	154,755,064	401,697,544	1,501,466,342	74,894,286	35,568,259	52,453,849	17,239,729

SCHEDULE C8

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Rate Base Investment	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	3,517,640,311	3,487,558,394	30,081,916	-	-	-	-	-	-	-
DIESEL	33,897,890	14,193,829	-	-	-	-	-	-	-	19,704,061
SUBSTATION	611,917,630	-	181,189,584	39,414,883	57,050,761	331,852,423	-	2,409,980	-	-
- HVDC	643,824,785	288,150,007	355,674,778	-	-	-	-	-	-	-
TRANSMISSION	350,545,552	-	193,965,916	79,585,031	76,994,605	-	-	-	-	-
- HVDC	122,774,928	122,774,928	-	-	-	-	-	-	-	-
DISTRIBUTION	926,754,485	-	-	-	-	891,197,032	-	-	34,034,299	1,523,155
SUBTRANSMISSION	181,107,491	-	-	-	172,952,097	8,155,394	-	-	-	-
TRANSFORMERS										
- SUBSTATION	14,066,220	-	3,615,391	644,231	1,661,712	8,144,885	-	-	-	-
- DISTRIBUTION	4,393,382	-	-	-	-	4,393,382	-	-	-	-
METERS	29,788,657	-	-	-	-	29,788,657	-	-	-	-
METERING TRANSFORMERS	3,393,599	-	-	-	-	3,393,599	-	-	-	-
BUILDINGS	289,432,154	126,503,438	29,441,667	12,932,624	19,955,069	65,200,411	27,050,845	-	7,866,571	481,529
COMMUNICATION	242,558,767	45,533,587	51,729,689	6,940,102	44,255,575	58,952,846	-	35,146,969	-	-
GENERAL EQUIPMENT	232,636,886	73,979,146	25,995,119	11,416,786	17,625,806	57,922,902	38,710,690	-	6,985,762	675
SUBTOTAL	7,204,732,736	4,158,693,330	871,694,061	150,933,657	390,495,624	1,459,001,531	65,761,535	37,556,949	48,886,631	21,709,419
MOTOR VEHICLES	103,394,043									
Total Rate Base Investment	7,308,126,779	4,158,693,330	871,694,061	150,933,657	390,495,624	1,459,001,531	65,761,535	37,556,949	48,886,631	21,709,419

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Interest & Reserve Expense	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocation Lighting	Direct Allocation Diesel
GENERATION	307,203,253	304,576,133	2,627,120	-	-	-	-	-	-	-
DIESEL	2,960,377	1,239,578	-	-	-	-	-	-	-	1,720,799
SUBSTATION	53,440,110	-	15,823,684	3,442,188	4,982,368	28,981,401	-	210,469	-	-
- HVDC	56,226,632	25,164,773	31,061,859	-	-	-	-	-	-	-
TRANSMISSION	30,613,913	-	16,939,469	6,950,335	6,724,108	-	-	-	-	-
- HVDC	10,722,204	10,722,204	-	-	-	-	-	-	-	-
DISTRIBUTION	80,935,504	-	-	-	-	77,830,194	-	-	2,972,290	133,020
SUBTRANSMISSION	15,816,515	-	-	-	15,104,286	712,228	-	-	-	-
TRANSFORMERS										
- SUBSTATION	1,228,434	-	315,740	56,262	145,121	711,311	-	-	-	-
- DISTRIBUTION	383,684	-	-	-	-	383,684	-	-	-	-
METERS	2,601,509	-	-	-	-	2,601,509	-	-	-	-
METERING TRANSFORMERS	296,370	-	-	-	-	296,370	-	-	-	-
BUILDINGS	5,827,705	2,547,142	592,807	260,398	401,794	1,312,808	544,668	-	158,393	9,696
COMMUNICATION	21,183,190	3,976,548	4,517,667	606,094	3,864,937	5,148,481	-	3,069,462	-	-
GENERAL EQUIPMENT	4,684,134	1,489,567	523,411	229,877	354,895	1,166,275	779,438	-	140,658	14
SUBTOTAL	594,123,534	349,715,945	72,401,758	11,545,155	31,577,509	119,144,261	1,324,106	3,279,931	3,271,341	1,863,528
MOTOR VEHICLES	-									
Total Interest Exp Allocated	594,123,534	349,715,945	72,401,758	11,545,155	31,577,509	119,144,261	1,324,106	3,279,931	3,271,341	1,863,528

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Rate Based for Capital Tax	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	3,539,594,384	3,509,916,702	29,677,682	-	-	-	-	-	-	-
DIESEL	31,615,835	13,940,094	-	-	-	-	-	-	-	17,675,741
SUBSTATION	623,355,952	-	185,786,803	39,082,105	60,263,791	335,967,549	-	2,255,703	-	-
- HVDC	640,510,326	286,778,448	353,731,878	-	-	-	-	-	-	-
TRANSMISSION	350,612,982	-	195,189,031	78,555,544	76,868,407	-	-	-	-	-
- HVDC	121,155,482	121,155,482	-	-	-	-	-	-	-	-
DISTRIBUTION	937,858,217	-	-	-	-	902,374,171	-	-	34,030,439	1,453,607
SUBTRANSMISSION	185,805,154	-	-	-	177,514,689	8,290,465	-	-	-	-
TRANSFORMERS										
- SUBSTATION	13,635,843	-	3,327,123	593,368	1,504,648	8,210,704	-	-	-	-
- DISTRIBUTION	4,028,665	-	-	-	-	4,028,665	-	-	-	-
METERS	31,463,257	-	-	-	-	31,463,257	-	-	-	-
METERING TRANSFORMERS	3,289,370	-	-	-	-	3,289,370	-	-	-	-
BUILDINGS	415,022,885	180,913,997	42,364,037	18,608,939	28,713,465	93,891,452	38,726,260	-	11,328,524	476,210
COMMUNICATION	248,452,763	45,105,543	62,587,076	6,713,132	42,991,315	57,743,142	-	33,312,555	-	-
GENERAL EQUIPMENT	245,698,042	77,752,215	27,624,566	12,132,458	18,730,455	61,410,547	40,641,409	-	7,406,392	-
SUBTOTAL	7,392,099,155	4,235,562,481	900,288,196	155,685,545	406,586,769	1,506,669,322	79,367,670	35,568,259	52,765,355	19,605,558
MOTOR VEHICLES	-									
RATE BASE FOR CAPITAL TAX	7,392,099,155	4,235,562,481	900,288,196	155,685,545	406,586,769	1,506,669,322	79,367,670	35,568,259	52,765,355	19,605,558

2008 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2008

Asset Class	Capital Tax	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocation Lighting	Direct Allocation Diesel
GENERATION	18,309,207	18,155,693	153,513	-	-	-	-	-	-	-
DIESEL	163,539	72,108	-	-	-	-	-	-	-	91,431
SUBSTATION	3,224,424	-	961,017	202,159	311,726	1,737,854	-	11,668	-	-
- HVDC	3,313,158	1,483,415	1,829,744	-	-	-	-	-	-	-
TRANSMISSION	1,813,610	-	1,009,651	406,343	397,616	-	-	-	-	-
- HVDC	626,699	626,699	-	-	-	-	-	-	-	-
DISTRIBUTION	4,851,245	-	-	-	-	4,667,697	-	-	176,029	7,519
SUBTRANSMISSION	961,112	-	-	-	918,228	42,884	-	-	-	-
TRANSFORMERS										
- SUBSTATION	70,534	-	17,210	3,069	7,783	42,471	-	-	-	-
- DISTRIBUTION	20,839	-	-	-	-	20,839	-	-	-	-
METERS	162,750	-	-	-	-	162,750	-	-	-	-
METERING TRANSFORMERS	17,015	-	-	-	-	17,015	-	-	-	-
BUILDINGS	2,146,783	935,811	219,136	96,258	148,526	485,671	200,319	-	58,599	2,463
COMMUNICATION	1,285,168	233,317	323,743	34,725	222,381	298,687	-	172,315	-	-
GENERAL EQUIPMENT	1,270,919	402,188	142,893	62,757	96,887	317,657	210,225	-	38,311	-
SUBTOTAL	38,237,000	21,909,230	4,656,907	805,312	2,103,145	7,793,526	410,544	183,983	272,939	101,413
MOTOR VEHICLES	-									
CAPITAL TAX ALLOCATION	38,237,000	21,909,230	4,656,907	805,312	2,103,145	7,793,526	410,544	183,983	272,939	101,413

2008 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2008
Functionalization of Operating Costs

Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Generation External Marketing	4,254,869	-								4,254,869
Common Generation Costs	28,823,326	16,210,005					-			12,613,320
Generating Station Costs	39,643,050	39,643,050					-			-
Other Generation Related Costs	244,506	244,506	-	-	-	-	-	-	-	
Dedicated Gen. Facilities	39,887,556	39,887,556					-	-	-	-
Hydraulic Generating Stations	131,265,747	131,265,747					-			
Other Hydraulic Generation Related Costs	18,072,702	18,072,702								
Hydraulic Generation Costs	149,338,448	149,338,448					-			
Thermal Generating Station	43,730,784	20,498,684					-			23,232,100
Non-Dedicated Gen. Facilities	193,069,232	169,837,132					-			23,232,100
Generation Facilities Costs	232,956,788	209,724,688					-	-	-	23,232,100
Purchased Power/Export Costs	135,251,880	-								135,251,880
Generation Facilities & Costs	***397,031,994***	***225,934,694***					-	-	-	***171,097,300***
Transmission External Marketing	5,736,214	-	-	-						5,736,214
Common Trans. Costs/Revenues	21,089,779	867,224	12,020,641	2,465,700			-			5,736,214
Generation Switching Stations	7,464,512	-	7,464,512							
HVDC & Collector Facilities	33,383,767	20,806,515	12,577,252							
Networked AC Facilities	3,441,892	-	3,441,892							
Generation Access Transmission	44,290,171	20,806,515	23,483,657							
Regional Networked Trans.	473,214	-	473,214							
Future Transmission Line ROW	-	-	-							
Transmission Common	12,417,121	-	11,997,053	342,414			77,655			
Transmission Facilities/Costs	***78,270,285***	***21,673,739***	***47,974,565***	***2,808,113***			***77,655***			***5,736,214***
Common Subtransmission Costs	5,381,368	-	-	5,381,368						
Subtrans. Facilities & Costs	***23,423,371***	-	-	***17,725,186***	***5,698,185***	-	-	-	-	-
Dist. Facilities & Costs	***63,597,381***	-	-	-	***56,661,958***	-	-	-	***6,935,423***	-
Customer Service Costs	***72,563,167***					***72,563,167***	-	-	-	-
Isolated Diesel Facilities	***4,969,469***	-	-	-	-	-	-	***4,969,469***		
Communication & Control System	***10,451,090***	***4,895,674***	***122,117***	***2,471,393***	***672,271***		***2,289,634***	-	-	-
	657,791,658	**254,878,113**	**50,268,899**	**23,655,106**	**65,320,678**	**72,563,167**	**2,367,288**	**4,969,469**	**6,935,423**	**176,833,514**

2008 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ APPROVED RATES
For Year Ended March 31, 2008

Revenue Class	Unadjusted Revenue	Diesel	To Misc Revenue	Other Accrual	General Consumer Adjustment	Total adjusted Revenue	Export Adj to Offset Uniform Rates	Total Revenue After Uniform Rates Adjustment
Residential								
Residential	409,140,377			358,598	1,812,569	411,311,544	14,362,999	425,674,543
Seasonal	5,118,126				22,674	5,140,800	1,007,083	6,147,883
Water Heating	1,307,029			1,146	5,790	1,313,965		1,313,965
	415,565,532	-		359,743	1,841,034	417,766,309	15,370,082	433,136,391
General Service - Small								
Non Demand	90,214,817			79,070	399,669	90,693,556	1,196,248	91,889,804
Seasonal	442,982				1,962	444,944	31,809	476,753
Water Heating	525,550			461	2,328	528,339		528,339
Total Non Demand	91,183,349	-		79,531	403,959	91,666,839	1,228,057	92,894,896
Demand	111,214,758			97,476	492,702	111,804,936	356,658	112,161,594
	111,214,758	-	-	97,476	492,702	111,804,936	356,658	112,161,594
SEP								
GSM	1,343,835			1,178	5,953	1,350,966		1,350,966
GSL	210,228					210,228		210,228
	1,554,063			1,178	5,953	1,561,194	-	1,561,194

2008 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ APPROVED RATES
For Year Ended March 31, 2008

Revenue Class	Unadjusted Revenue	Diesel	To Misc Revenue	Other Accrual	General Consumer Adjustment	Total adjusted Revenue	Export Adj to Offset Uniform Rates	Total Revenue After Uniform Rates Adjustment
General Service - Medium	143,393,345			125,679	635,260	144,154,284	31,714	144,185,998
	143,393,345	-		125,679	635,260	144,154,284	31,714	144,185,998
General Service - Large								
0 - 30 Kv	65,577,500			57,476	290,521	65,925,497		65,925,497
30 - 100 Kv	28,347,433					28,347,433		28,347,433
31 - 100 Kv Curtailable	7,019,660					7,019,660		7,019,660
Over - 100 Kv	86,112,555					86,112,555		86,112,555
Over - 100 Kv Curtailable	77,891,789					77,891,789		77,891,789
	264,948,937	-		57,476	290,521	265,296,934	-	265,296,934
Area & Roadway Lighting								
Street Lighting	16,400,205					16,400,205	217,275	16,617,480
Sentinel Lighting	2,629,602	(17,848)		2,289	11,571	2,625,614		2,625,614
	19,029,807	(17,848)	-	2,289	11,571	19,025,819	217,275	19,243,094
Diesel								
Residential	569,087					569,087		569,087
Street Lighting		17,848				17,848		17,848
Full Cost	4,178,341					4,178,341		4,178,341
	4,747,428	17,848		-	-	4,765,276	-	4,765,276
Gen. Consumers Before Adjustment	1,051,637,219	-	-	723,373	3,681,000	1,056,041,592	17,203,786	1,073,245,378
Accrual - Other	723,373			(723,373)				
Miscellaneous - Non-Energy	511,250		(511,250)		-	-		
Late Pmt Charges & Cust Adjustments	3,681,000				(3,681,000)	-		
Total General Consumers	1,056,552,842	-	(511,250)	-	-	1,056,041,592	17,203,786	1,073,245,378
Extra-Provincial	550,996,000		513,557			551,509,557		551,509,557
Other (Non Energy Net of Subsidiaries)	6,074,000		(6,074,000)			-		-
Total Revenue	1,613,622,842	-	(6,071,693)	-	-	1,607,551,149	17,203,786	1,624,754,935

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2008

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:		
General Consumers		1,040.0
Additional GCR		41.6
Extra Provincial		551.0
Other (non-energy)		20.4
Total Revenue Per Financial Forecast		1,652.9
Cost of Service Adjustments		
a. transfer of Other Revenue (non-energy) to Miscellaneous Revenue		(6.1)
b. transfer from General Consumers Revenue (non-energy) to Misc Revenue		0.0
c. remove 2008 Rate Increase to GCR		(24.7)
d. remove Subsidiaries' Revenue from COSS		(14.6)
Total Revenue Per Cost of Service Study	$	1,607.6

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2008

Rate Base Calculation and Deferred Items

Allocation of net interest expense and reserve contribution is based upon average net plant in-service forecast for fiscal years 2007 and 2008 adjusted for net deferred items and net major capital additions forecast to come into service during fiscal year 2007/08 which are included on an in-service date basis. This calculation is summarized below:

	2007	2008
Net Investment (Excluding Motor Vehicles)	$ 6,781.6	$ 7,134.1
Add: Total Net Deferred Items	235.8	258.0
Less: Major Capital Item Additions 2008		(239.2)
	$ 7,017.4	$ 7,152.9
Average Investment (2007 + 2008) ÷ 2		$ 7,085.1
Add: Major Capital Item Additions 2008 on an in-service date basis		119.6
		$ 7,204.7

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SECTION D

LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2007/08 has been estimated using forecast energy and peak demand from the System Load Forecast and available class load information. Load research data are used to estimate the average top 50 hourly peaks during both the summer and winter. Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2007/08 the DSM savings are forecast to be 199.3 GW.h and 32.8 MW at Generation, or 175.7 and 28.9 measured at the meter. For the purposes of the COSS, MW savings due to the Curtailable Rate Program are not included in DSM - instead the affected classes of service, General Service Large 30 - 100 kV curtailable and >100 kV curtailable, are credited with a cost reduction equal to the value of curtailable load.

Schedule D1 outlines Manitoba Hydro's forecast energy and calculation of forecast demand for 2007/08 fiscal year. Forecasted consumption by rate class is shown seasonally; seasonal energies are displayed to demonstrate the calculation of the demand allocator. The average of winter and summer demands (2 CP) is used to allocate Transmission related costs. In PCOSS08 Transmission costs are allocated entirely on demand. The distinction between those lines serving the export market (allocated on energy) and all other transmission lines (allocated on demand) as done in the Recommended version of PCOSS06 is no longer made.

Generation costs are allocated based on energies weighted on marginal cost between the twelve time of use periods: Winter Peak/Off-Peak/Shoulder, Spring Peak/Off-Peak/Shoulder, Summer Peak/Off-Peak/Shoulder and Fall Peak/Off-Peak/Shoulder. The development of these allocators is outlined in Schedule D2.

Schedule D3 shows the computation of expected Transmission and Distribution losses on Manitoba Hydro's Integrated System. Common bus energy and coincident peak losses of 2,127,289 MW.h and 407.7 MW respectively have been taken from the 2006 System Load Forecast and adjusted to reflect forecast DSM savings. These losses apply to forecast Manitoba Hydro firm energy and peak. Distribution energy losses are simply the difference between sales at meters and energy at common bus. Distribution losses at time of system peak are calculated in Schedule D3 based on the approach used by Mr. M. W. Gustafson in his article, "Approximating the System Loss Equation". The adjustment factor of -13% for temperature reflects the reduction in the resistivity of conductors between 0°C and -30°C, 0°C being the average

Winnipeg temperature and the ambient temperature on the peak load day usually being around -30°C.

Schedule D3 also shows the difference between total coincident peak calculated by applying class load factors in the PCOSS08 from the system peak forecasted in the 2006 System Load Forecast for the 2008 fiscal year. This difference of 132 MW is applied as an adjustment to all classes' estimated coincident peak based upon Load Research results.

Schedule D5 summarizes the load data and computations for all customer classes. The sources of data and derivation of estimates are elaborated upon below.

Assignment of Losses

In order to properly reflect cost causation in allocating energy and capacity costs, energy sales and demand must be measured at Generation as opposed to the meter. This is accomplished by assigning Distribution and Transmission losses to each of the rate classes based upon the voltage level in which they receive service.

In this process, Distribution energy losses are assigned first. Customers receiving service at greater than 30 kV have been assigned losses based upon a uniform percentage of metered sales. Customers receiving service at supply voltage less than 30 kV share in the residual losses. A differential percentage has been assigned depending upon whether service is taken at primary or secondary voltage level. General Service Small - Three Phase, General Service Medium and General Service Large are assumed to receive service at a primary service level, while Residential, Area and Roadway Lighting and General Service Small - Single Phase are assumed to receive service at the secondary level. Capacity losses on the Distribution system are assigned in a similar manner.

The table below summarizes the assignment of Distribution energy losses and Schedule D6 shows the results of this assignment based upon sales at the meter for both energy and capacity.

	Service Supply Voltage	
	30 – 100 kV	**100 kV**
Losses Assigned Based on Sales at Meter		
Customer-owned transformation	1.95%	N/A
Utility-owned transformation	3.26%	1.30%

Residual Losses Assigned on a Differential % Basis	
Secondary	+1.6%
Primary – Utility-owned transformation	-0.1%
Primary – Customer-owned transformation	-1.0%

Transmission losses are shared equally by all rate classes based upon deliveries from common bus, i.e., sales at the meter plus assigned distribution losses.

Load Research Project

Manitoba Hydro has made a commitment to an active program of electric load research. One of the reasons for undertaking this program is to support Cost of Service Studies with particular emphasis on cost causation to aid in rate design. In addition, the program is to support an aggressive DSM Program through improved end-use load and energy data and to support the Load Forecast function as it adopts forecasting methods which rely on end-use based procedures to forecast sales and loads by customer class. The scope of Load Research has also been expanded in order to integrate the load shapes of those customers in the former Winnipeg Hydro service area.

For Cost of Service/Rate Design, there are twelve groups overall for which the project is to provide demand and energy estimates with known precision, i.e., 90% confidence with an accuracy of ±10%. To obtain this objective, a sample size of 1,184 customers was selected from Manitoba Hydro's various customer classes. All General Service Large, 30 - 100 kV and >100 kV customers are sampled. Class data for 2005/06, is used in the PCOSS to estimate class demands for use in allocating demand-related costs.

Development of Class Loads

1. Residential Class

The 2007/08 forecast kW.h sales to the Residential Class and the forecast number of customers are taken from the 2006 System Load Forecast. Load Forecasting further processes these estimates to allocate a share of farm customers and consumption into Residential Class/subclasses and to provide separate information for Flat Rate Water Heating and Seasonal customers.

In Schedule D5, energy sales have been reduced by the forecast savings of 42 GW.h applicable to the residential DSM Programs before energy at the customer meter is grossed up by Distribution losses and Transmission losses to yield estimated energy generated to serve the various subclasses of the Residential Class.

The coincident peak demand at the customer meters has been estimated by applying coincident peak load factors to the kW.h sales. Coincident peak load factors have been developed from load research data based on the average top 50 hourly peaks during the year.

The Flat Rate Water Heating Class coincident demand is estimated on the basis of 4.1 kW customer peak and 80% coincident factor of individual customers with the system peak.

The Seasonal Class coincident peak load factor is taken from previous Peak Load Responsibility studies as new information from Load Research is limited. The coincident peak load factor was previously determined to be 157.8%.

The estimated coincident peaks at the meter have been adjusted by 72.6 MW to incorporate Residential's share of the total calibration factor derived in Schedule D3. The applicable share of each class's contribution to the calibration factor is provided by the error margin in the Load Research sample.

These loads have been reduced by the forecast capacity savings of 3.8 MW to be achieved through the residential DSM Programs.

Estimated Distribution losses and Transmission losses are applied to provide the estimate of class coincident peak at Generation. Load Research results available for 2006 are then applied to yield class non-coincident peaks at meter and at Generation.

2. General Service Small Class

The General Service Small class consists of two major subgroups; customers who are demand metered (General Service Small Demand, load over 50 kV.A billing demand, but not exceeding 200 kV.A) and those with no demand meters (General Service Small Non-Demand, load less than 50 kV.A billing demand). In addition, loads shown in Schedule D5 have been separated into single phase and three phase based upon 2006 data. Also shown are loads for small subgroups: Water Heating, Seasonal and Flat Rate Services which include end uses such as telephone booths and traffic control signals.

As with the Residential Class, General Service Small kW.h sales and customer counts are taken from the 2006 System Load Forecast and further processed to yield the rate subgroup forecasts shown in Schedule D5. Also similarly, the sales have been reduced by the forecast DSM energy and capacity savings of 58.1 GW.h and 11.5 MW before being grossed up to include Distribution and Transmission losses.

The General Service Small Demand subgroup's coincident peak has been estimated by applying coincidence factors to the sum of class demands in the average of the top 50 hourly system peaks for the year.

For the General Service Small Non-Demand subgroup, the coincident peak load factors were determined using load research information for 2006. The same load factors have been applied to both single and three phase customers.

Coincident peak load factors for the small subgroups have been estimated using approaches similar to those employed for past studies as new information from load research is limited. The Seasonal coincident peak load factor of 162.5% is the same as used in previous studies.

The estimated coincident peaks at the meter have been adjusted by 42.3 MW to reflect General Service Small share of the adjustment required to reconcile coincident peak at meter.

The coincident peak load factors are used to derive class coincident peak's at the meter. Distribution and Transmission peak MW losses are added to give coincident peak at Generation. Finally, class coincidence factors, based on the load research information available for 2006 have been applied to derive class non-coincident peaks.

3. General Service Medium

General Service Medium includes 1,801 customers with demands between 200 and 2,000 kV.A, who are served through utility-owned transformation. All these customers are demand metered. A few, mainly those served above distribution voltages, have historically been metered with recording pulse meters which provide a permanent record of 15-minute interval demands. Currently 225 customers are pulse metered.

Customer and kW.h sales data are derived from the load forecast and apportioned among service voltages on the basis of recent past experience. DSM savings of 38.3 GW.h and 7.2 MW have been assigned to this class.

Application of average top 50 hourly system peaks yield the load data outlined in Schedule D5.

General Service Medium estimated coincident peaks at the meter have been adjusted by 16.7 MW to reflect their share of the adjustment required to reconcile coincident peak at the meter.

Most General Service Medium customers are served at Distribution voltages and therefore are assigned responsibility for the same percentage losses as General Service Small three phase customers. As with the other classes General Service Medium customers are assigned Distribution energy losses and Transmission energy losses as measured at common bus.

4. General Service Large

For customers in this class, the coincident peak load factors and coincident factors have been based upon data from 2006. Load information for this class has been historically available. Sixty-three percent of the customers in the 0 - 30 kV subclass, 96% of the customers in the 30 - 100 kV subclass and 100% of the customers in the over 100 kV subclass are pulse metered.

The estimated coincident peaks at the meter have been adjusted by 0.3 MW to reflect General Service Large's share of the adjustment required to reconcile coincident peak at meter.

DSM savings assigned to this class total 37.3 GW.h and 6.4 MW. Note that these figures do not include savings from curtailable customers within this class of service. Instead these customers are credited with a cost reduction equal to the value of curtailable load.

Customers over 100 kV in this class are not assigned distribution losses. For customers served at 30 - 100 kV distribution energy losses are equal to 1.5% of sales and below 30 kV energy losses are assigned losses at 4.5% of sales.

5. Surplus Energy Program

Surplus Energy Program (SEP) energy sales are taken from the 2006 System Load Forecast. Customers and forecast energy have been separated into service voltage levels and into utility or customer owned transformation. Load and coincident factors used to estimate class loads have been based upon data from load research information available for fiscal year 2006.

Distribution and Transmission losses are assigned consistent with the other rate classifications, service voltage levels and transformation ownership.

6. Area and Roadway Lighting

Sentinel Lights

Sentinel light energy consumption and customer count are taken from the 2006 System Load Forecast. The customer count has been derated by 90% for purposes of allocating customer-related costs. The class non-coincident peak results from the total wattage of luminaires served. Load Research indicates that these luminaires are lighted, on average 38.2% of the peak 50 hours, with a class coincident peak of 119.7%. These factors are applied to forecast energy to yield forecast peaks for the class.

No DSM savings have been assigned to Sentinel Lighting class as past DSM is now fully reflected in load forecast estimates.

Sentinel lights are served from the Distribution system and are therefore assigned the same energy and peak loss percentage as the Residential Class.

Street Lights

Street light energy consumption forecast for 2007/08 is based on the inventory wattage multiplied by 4,252 hours of use per year, a figure based on the most recent Load Research results. The customer count is based on March 2006 actual billing data plus forecast additions to the system of 2,543 lights to year end 2008. The customer count represents the number of forecast street lights derated by 90%. Street lights also show a class coincident peak load factor of 119.7% and coincidence factor of 38.2%. No DSM savings have been assigned to these customers as past DSM is already fully reflected in inventory wattage data.

2008 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP) at Generation Peak

			Winter				*SUMMER*			D14
	Forcast Total Energy @ Generation (E10)	**Avg % of Yearly Energy**	**Estimated Seasonal Energy**	**Seasonal CP LF**	**Estimated Seasonal Demand**	**Avg % of Yearly Energy**	**Estimated Seasonal Energy**	**Seasonal CP LF**	**Estimated Seasonal Demand**	**2CP Estimated Demand**
Residential										
Residential	7,594,130,833	63.1%	4,794,857,598	84.6%	1,297,596	36.9%	2,799,273,234	88.0%	720,738	1,009,167
Seasonal	72,433,609	34.0%	24,643,092	162.5%	3,472	66.0%	47,790,517	162.5%	6,660	5,066
Water Heating	22,814,950	49.6%	11,316,215	126.0%	2,056	50.4%	8,809,416	126.0%	1,583	1,820
Total Residential	7,689,379,392		4,830,816,906		1,303,124		2,855,873,167		728,981	1,016,053
GS Small										
Non-Demand	1,533,277,628	57.8%	886,234,469	72.3%	280,597	42.2%	647,043,159	73.1%	200,408	240,502
Demand	2,353,934,217	57.6%	1,355,866,109	81.3%	381,807	42.4%	998,068,108	82.6%	273,622	327,714
Subtotal	3,887,211,846		2,242,100,579		662,403		1,645,111,267		474,030	568,217
Seasonal	5,564,622	20.2%	1,124,054	162.5%	158	79.8%	3,781,000	162.5%	527	343
Water Heating	7,135,809	49.6%	3,539,361	106.0%	764	50.4%	3,596,448	106.0%	768	766
Total GSS	3,899,912,277		2,246,763,994		663,326		1,652,488,715		475,325	569,326
General Service - Medium	3,392,121,243	53.2%	1,805,771,384	82.1%	503,543	46.8%	1,586,349,858	81.7%	439,691	471,617
General Service - Large										
0 - 30 Kv	1,838,244,462	51.0%	936,624,149	80.9%	265,071	49.0%	901,620,313	84.4%	241,909	253,490
30 - 100 Kv	853,284,107	52.4%	447,114,283	86.8%	117,918	47.6%	406,169,824	98.8%	93,125	105,521
30 - 100 Kv - Curtailed Cust	243,808,758	49.8%	121,416,761	111.8%	24,863	50.2%	122,391,996	98.9%	28,015	26,439
Over 100 Kv	2,917,852,601	53.1%	1,548,819,005	98.1%	361,577	46.9%	1,369,033,596	110.2%	281,330	321,454
Over 100 Kv - Curtailed Cust	2,794,336,359	51.1%	1,426,919,643	99.1%	329,688	48.9%	1,367,416,716	98.3%	314,854	322,271
Total G.S.- Large	8,647,526,287		4,480,893,842		1,099,117		4,166,632,445		959,233	1,029,175
Street Lighting	112,223,965	58.2%	65,306,569	86.7%	17,255	41.8%	46,917,396	0.0%	-	8,627
Total - General Consumers	23,741,163,164		13,429,552,695		3,586,365		10,308,261,582		2,603,231	3,094,798
Extra Provincial	8,462,000,000	40.3%	3,409,000,000	94.5%	826,171	59.7%	5,053,000,000	89.4%	1,280,245	1,053,208
Integrated System	32,203,163,164		16,838,552,695		4,412,536		15,361,261,582		3,883,476	4,148,006

2007/2008 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Energy (MW.h) Weighted by Marginal Cost

	Spring			Summer			Fall			Winter				Weighted
	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Energy
Residential	245,865	450,932	312,733	483,411	908,633	482,597	321,060	580,262	396,611	853,377	1,542,168	1,016,481	7,594,131	17,068,870
Residential FRWH	926	1,698	1,178	1,961	3,686	1,958	941	1,700	1,162	1,902	3,437	2,266	22,815	50,662
Residential Seasonal	3,410	6,254	4,337	8,216	15,443	8,202	2,509	4,535	3,100	4,109	7,425	4,894	72,434	159,493
GS Small Non-Demand	59,384	102,672	58,273	133,901	190,013	106,957	68,944	117,172	68,330	168,092	285,195	174,343	1,533,278	3,498,485
GS Small Non-Demand FRWH	321	554	315	739	1,049	590	322	548	319	637	1,081	661	7,136	16,162
GS Small Non-Demand Seasonal	324	561	318	920	1,306	735	176	300	175	201	341	208	5,565	12,445
GS Small Demand	93,539	157,827	100,612	193,465	311,383	187,367	102,938	178,392	112,580	233,636	407,126	275,070	2,353,934	5,282,478
GS Medium	136,421	237,394	142,921	296,028	484,027	285,570	146,645	260,089	157,683	324,202	558,796	362,345	3,392,121	7,620,179
GS Large 750-30kV	79,694	131,006	85,236	171,983	268,591	175,879	80,747	135,242	89,395	166,070	270,302	184,099	1,838,244	4,100,770
GS Large 30-100kV	29,968	56,672	46,196	59,761	110,067	88,473	31,681	59,129	47,350	75,491	138,967	109,528	853,284	1,845,222
GS Large 30-100kV Curtailable	8,563	16,193	13,200	17,075	31,449	25,280	9,052	16,895	13,529	21,570	39,707	31,296	243,809	527,235
GS Large > 100kV	115,558	214,631	167,805	201,639	369,309	291,557	114,455	222,282	171,399	243,018	451,386	354,813	2,917,853	6,294,677
GS >100kV Curtailable	101,089	192,887	149,531	213,639	405,908	315,126	103,296	207,496	159,642	216,303	411,581	317,837	2,794,336	6,013,997
Street Lights	-	4,265	10,549	337	7,968	21,098	3,479	6,060	12,681	7,407	13,018	25,363	112,224	203,626
Totals	875,061	1,573,548	1,093,206	1,783,074	3,108,832	1,991,391	986,246	1,790,103	1,233,956	2,316,015	4,130,530	2,859,203	23,741,163	52,694,301
Exports	182,772	351,739	254,515	414,841	782,925	527,052	163,977	343,517	250,688	291,802	577,914	382,257	4,524,000	9,786,959
12 Period Weightings	**2.513**	**2.144**	**1.246**	**3.258**	**2.388**	**1.000**	**2.624**	**2.155**	**1.396**	**3.406**	**2.262**	**1.796**		

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
March 31, 2008

CALCULATION OF LOSSES

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	23,828,219,630
Common Bus Losses (After DSM)	2,127,209,289
Deliveries From Common Bus	21,701,010,341
Sales at Meter	20,866,866,830
Distribution Losses	834,143,511

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	3,934.5
Common Bus Losses (After DSM)	407.7
Deliveries From Common Bus	3,526.8
Calculated Distribution Losses	203.3
Calculated Demand at Meter (CP Load Factors)	3,455.4
Less: Adj made for curtailable load added back	-
Adjustment To Reconcile	(131.9)

MANITOBA HYDRO
2008 PROSPECTIVE COST OF SERVICE STUDY
March 31, 2008
DETERMINATION OF COINCIDENT PEAK DISTRIBUTION LOSSES

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	Losses	Energy @ Common Bus
RESIDENTIAL	6,577,526,000	425,401,801	7,002,927,801
G.S.S. SINGLE PHASE	1,410,338,001	91,213,676	1,501,551,677
G.S.S. THREE PHASE	1,956,909,199	93,295,737	2,050,204,936
* G.S.M.	2,969,717,220	141,581,407	3,111,298,627
* G.S.L. O - 30	1,614,502,880	62,440,974	1,676,943,854
G.S.L. 30 - 100	768,147,526	11,522,213	779,669,739
LIGHTING	95,996,830	6,208,599	102,205,429
MAN. HYDRO CONSTRUCTION	52,000,000	2,479,102	54,479,102
	15,445,137,656	834,143,511	16,279,281,168

* (includes SEP sales)

2) COINCIDENT PEAK AT COMMON BUS

C.P. AT GENERATION	3,934.50
LESS SALES AT CB LEVEL :	
- EXPORTS	0.00
- * G.S.L. >100	(348.43)
C.B. LOSSES	(407.69)
EXPORT LOSSES	0.00
COINCIDENT PEAK AT COMMON BUS	3,178.38

3) LOAD FACTOR AT COMMON BUS 58.3%
(Hours per Year = 8,784)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = (0.08 x 58.31%) + (0.92 x $(58.31\%)^2$)
= 0.359443

5) NO LOAD LOSS FACTOR AS A PERCENTAGE OF DISTRIBUTION ENERGY LOSSES 18.00%

a) 834,144 x 0.1800 = 150,146 MW.H

b) $\frac{834{,}144 \times 0.1800}{8{,}784}$ = 17.1 MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{834{,}144. - 150{,}146}{8{,}784 \times (3{,}178.38)^2 \times 0.35944}$$

= 0.000021

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

= $17.09 + 0.000021 \times (3{,}178.38)^2$
= 233.73

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 203.345 MW

10) RELATIONSHIP PEAK TO AVERAGE LOSSES (based on sales @ meter).

AVERAGE (KW.h)	834,144	/ 15,445,138	= 5.40%
PEAK (MW)	203.35	/ 2,975.039	= 6.84%

2008 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Energy Data

	Forecast # Cust. **C90**	Forecast Total KW.h Sales Before DSM	DSM KW.h Savings	Total KW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	KW.h Generated Adjusted **E10**
Residential							
Residential	430,295	6,538,090,000	(42,040,000)	6,496,050,000	420,132,337	677,948,495	7,594,130,833
Seasonal	20,118	61,960,000	-	61,960,000	4,007,266	6,466,343	72,433,609
Water Heating	5,490	19,516,000	-	19,516,000	1,262,198	2,036,752	22,814,950
Total Residential	455,903	6,619,566,000	(42,040,000)	6,577,526,000	425,401,801	686,451,591	7,689,379,392
GS Small - Single Phase							
Non-Demand	39,843	937,201,579	(19,818,120)	917,383,459	59,331,818	95,741,064	1,072,456,340
Demand	3,371	489,087,449	(6,996,907)	482,090,542	31,179,228	50,312,506	563,582,277
Subtotal	43,214	1,426,289,028	(26,815,027)	1,399,474,001	90,511,046	146,053,570	1,636,038,617
Seasonal	779	4,760,000	-	4,760,000	307,853	496,769	5,564,622
Water Heating	509	6,104,000	-	6,104,000	394,776	637,033	7,135,809
Total Single Phase	44,502	1,437,153,028	(26,815,027)	1,410,338,001	91,213,676	147,187,372	1,648,739,049
GS Small - Three Phase							
Non-Demand	10,911	409,238,420	(8,653,780)	400,584,640	19,097,891	41,138,756	460,821,288
Demand	5,877	1,578,912,552	(22,587,993)	1,556,324,559	74,197,846	159,829,536	1,790,351,940
Total Three Phase	16,788	1,988,150,972	(31,241,773)	1,956,909,199	93,295,737	200,968,292	2,251,173,228
Total G.S.Small							
Non-Demand	50,754	1,346,439,999	(28,471,900)	1,317,968,099	78,429,709	136,879,820	1,533,277,628
Demand	9,248	2,068,000,001	(29,584,900)	2,038,415,101	105,377,074	210,142,042	2,353,934,217
Sub-Total G.S. Small	60,002	3,414,440,000	(58,056,800)	3,356,383,200	183,806,784	347,021,862	3,887,211,846
Seasonal	779	4,760,000	-	4,760,000	307,853	496,769	5,564,622
Water Heating	509	6,104,000	-	6,104,000	394,776	637,033	7,135,809
Total GS Small	61,290	3,425,304,000	(58,056,800)	3,367,247,200	184,509,414	348,155,664	3,899,912,277
General Service - Medium	1,801	2,987,000,000	(38,282,780)	2,948,717,220	140,580,231	302,823,792	3,392,121,243
General Service - Large							
0 - 30 Kv	252	1,636,326,000	(24,523,120)	1,611,802,880	62,336,552	164,105,030	1,838,244,462
30 - 100 kV	27	769,958,000	(1,810,474)	768,147,526	8,961,613	76,174,968	853,284,107
30 - 100 kV - Curtailment Cust's	1	220,000,000	(517,306)	219,482,694	2,560,600	21,765,464	243,808,758
Over 100 Kv	11	2,662,716,000	(5,347,953)	2,657,368,047	-	260,484,554	2,917,852,601
Over 100 Kv - Curtailment Cust's	3	2,550,000,000	(5,121,567)	2,544,878,433	-	249,457,926	2,794,336,359
Total G.S.- Large	294	7,839,000,000	(37,320,420)	7,801,679,580	73,858,765	771,987,942	8,647,526,287
SEP							
GSM	22	21,000,000		21,000,000	1,001,176	2,156,633	24,157,809
GSL 0 - 30 Kv	6	2,700,000		2,700,000	104,423	274,899	3,079,322
Total SEP	28	23,700,000	-	23,700,000	1,105,599	2,431,532	27,237,131
Street Lighting	12,424	85,666,830	-	85,666,830	5,540,506	8,940,464	100,147,800
Sentinel Lighting	2,576	10,330,000	-	10,330,000	668,093	1,078,072	12,076,165
Total - Lighting	15,000	95,996,830	-	95,996,830	6,208,599	10,018,535	112,223,965
Total - General Consumers	534,316	20,990,566,830	(175,700,000)	20,814,866,830	831,664,409	2,121,869,056	23,768,400,295
Man Hydro - Construction		52,000,000		52,000,000	2,479,102	5,340,233	59,819,335
Integrated System	534,316	21,042,566,830	(175,700,000)	20,866,866,830	834,143,511	2,127,209,289	23,828,219,630

2008 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Demand Data

	CP Load Factor	CP @ Meter Before DSM Non-Recon MW	DSM MW Savings	CP @ Meter After DSM Non-Recon. MW	Adjust %'age	Adjust To Recon.	CP @ Meter Reconciled MW	Distrib Losses MW	Common Bus Losses MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
Residential												
Residential	53.6%	1,388.7	(3.8)	1,384.8	55.1%	(72.6)	1,312.2	116.0	165.1	87.8%	1,494.5	1,814.6
Seasonal	157.8%	4.5		4.5		-	4.5	0.4	0.6	8.0%	55.9	67.9
Water Heating	67.4%	3.3		3.3		-	3.3	0.3	0.4	80.0%	4.1	5.0
Total Residential	54.0%	1,396.4	(3.8)	1,392.6	55.1%	(72.6)	1,320.0	116.7	166.1	84.9%	1,554.5	1,887.5
GS Small - Single Phase												
Non-Demand	61.6%	173.2	(3.9)	169.3	10.4%	(13.7)	155.6	13.7	19.6	83.0%	187.4	227.6
Demand	68.1%	81.8	(1.4)	80.4	4.1%	(5.3)	75.0	6.6	9.4	87.2%	86.0	104.5
Subtotal	63.7%	255.0	(5.3)	249.6	14.4%	(19.1)	230.6	20.4	29.0	84.3%	273.5	332.0
Seasonal	162.5%	0.3		0.3			0.3	0.0	0.0	8.0%	4.2	5.1
Water Heating	68.9%	1.0		1.0			1.0	0.1	0.1	75.0%	1.3	1.6
Total Single Phase	63.8%	256.3	(5.3)	251.0	14.4%	(19.1)	231.9	20.5	29.2	83.1%	279.0	338.7
GS Small - Three Phase												
Non-Demand	61.6%	75.6	(1.7)	73.9	4.5%	(6.0)	67.9	4.5	8.4	83.0%	81.8	97.4
Demand	68.1%	263.9	(4.5)	259.5	13.1%	(17.3)	242.2	16.2	29.9	87.2%	277.8	330.6
Total Three Phase	66.7%	339.6	(6.2)	333.4	17.6%	(23.3)	310.1	20.7	38.2	86.2%	359.6	428.0
Total G.S.Small												
Non-Demand	60.3%	248.8	(5.7)	243.2	14.9%	(19.7)	223.5	18.3	27.9	83.0%	269.3	325.0
Demand	67.1%	345.7	(5.9)	339.8	17.1%	(22.6)	317.2	22.8	39.3	87.2%	363.8	435.0
Sub-Total G.S. Small	65.4%	594.5	(11.5)	583.0	32.1%	(42.3)	540.7	41.1	67.3	85.4%	633.1	760.0
Seasonal	162.7%	0.3	-	0.3	0.0%	-	0.3	0.0	0.0	8.0%	4.2	5.1
Water Heating	68.9%	1.0	-	1.0	0.0%	-	1.0	0.1	0.1	75.0%	1.3	1.6
Total GS Small	65.4%	595.9	(11.5)	584.4	32.1%	(42.3)	542.1	41.2	67.4	84.9%	638.6	766.7
General Service - Medium	73.6%	462.0	(7.2)	454.8	12.6%	(16.7)	438.1	29.3	54.0	90.6%	483.6	575.6
General Service - Large												
0 - 30 Kv	81.2%	229.4	(4.3)	225.2	0.2%	(0.3)	224.9	12.5	27.4	84.2%	267.1	314.5
30 - 100 kV	83.2%	105.4	(0.5)	104.9		-	104.9	1.6	12.3	77.7%	135.0	152.9
30 - 100 kV - Curtailment Cust's	98.0%	25.6	(0.1)	25.4		-	25.4	0.4	3.0	94.1%	27.0	30.6
Over 100 Kv	87.0%	348.4	(0.8)	347.6		-	347.6	-	40.2	91.8%	378.6	422.4
Over 100 Kv - Curtailment Cust's	97.3%	298.4	(0.7)	297.6		-	297.6	-	34.4	95.8%	310.7	346.6
Total G.S.- Large	88.6%	1,007.1	(6.4)	1,000.7	0.2%	(0.3)	1,000.5	14.5	117.3	89.5%	1,118.5	1,267.0
SEP												
GSM	44.8%	5.3		5.3		-	5.3	0.4	0.7	78.7%	6.8	8.1
GSL 0 - 30 Kv	88.8%	0.3		0.3		-	0.3	0.0	0.0	18.0%	1.9	2.3
Total SEP	47.5%	5.7	-	5.7		-	5.7	0.4	0.7	65.3%	8.7	10.3
Street Lighting	119.7%	8.1	-	8.1		-	8.1	0.7	1.0	38.2%	21.3	25.9
Sentinel Lighting	119.7%	1.0	-	1.0		-	1.0	0.1	0.1	38.2%	2.6	3.1
Total - Lighting	119.7%	9.1	-	9.1	0.0%	-	9.1	0.8	1.1	38.2%	23.9	29.0
Total - General Consumers	68.7%	3,476.3	(28.9)	3,447.3	100.0%	(131.9)	3,315.4	202.8	406.7	86.6%	3,827.7	4,536.1
Man Hydro - Construction	73.6%	8.0		8.0		-	8.0	0.5	1.0			
Integrated System	68.8%	3,484.3	(28.9)	3,455.4	100.0%	(131.9)	3,323.5	203.3	407.7			

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2008

Distribution Energy Losses Expressed as a Percentage of Kwh @ meter

	Class Avg
Export Sales	n/a
GS Large	
< 30	3.9%
30-100	1.2%
> 100	n/a
GS Medium	4.8%
GS Small	
3 Phase	4.8%
1 Phase	6.5%
Residential	6.5%
Area & Roadway Lighting	6.5%

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2008

Distribution Capacity Losses Expressed as a percentage of MW @ meter

	Class Avg
Export Sales	n/a
GS Large	
< 30	5.5%
30-100	1.5%
> 100	n/a
GS Medium	6.7%
GS Small	
3 Phase	6.7%
1 Phase	8.8%
Residential	8.8%
Area & Roadway Lighting	8.8%

SECTION E

ALLOCATION METHODS

Costs that have been functionalized and classified by cost component in Section C are allocated to the customer rate classes. Allocation methods are based upon:

- direct identification;
- the class's share of load (kW demand and kW.h consumption) to the system load; or
- the number of customers within the class to the total number of customers.

The allocation process uses class characteristics that comport with the classification of the cost: customer costs are allocated based on a weighted or un-weighted count of the number customers in each class; energy costs are allocated based on consumption by each class weighted for losses to reflect energy at Generation; and demand costs are allocated based on demand of each class also weighted for losses to reflect the load at Generation.

Since the adoption of Uniform Rates in 2001, the zonal distinction of Manitoba Hydro's information has eroded as it is no longer necessary to maintain customers in the correct zone for billing purposes. In PCOSS08 all allocations are made on an aggregate basis, as the key inputs into the study are no longer available on a zonal basis.

Customer counts and class loads developed in Section D are used in the allocation tables to assign classified costs to customer rate classes. In this allocation process, recognition is given to:

- Use of the facilities by the rate class (i.e. the loads of large industrial customers who receive service at the Transmission level are excluded from the allocation tables used to allocate Subtransmission and Distribution facilities).

- Cost distinction between rate classes in providing for customer-related facilities or services through the use of weighting factors (i.e. a three phase non-demand meter is approximately five times as costly as a single phase non-demand meter and this cost distinction is reflected in the customer weights used to allocate the capital cost of metering equipment).

The balance of this section is intended to provide an insight into the cost allocation process. This section contains the following schedules:

- Schedule E1 summarizes the classified costs by allocation table.
- Schedules E2 – E19 represent some of the main tables used to allocate classified costs.

Prospective Cost Of Service Study
March 31, 2008
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation		358,125	125,553	254,506	396	738,580
			358,125	125,553	254,506	396	738,580
D14	Transmission - 2CP		92,737	56,850	52,559		202,146
			92,737	56,850	52,559	-	202,146
D21	Subtrans		5,089	19,297	23,655		48,042
D22	Subtrans	Stations	5,447	-			5,447
D23	Subtrans	Lines	23,144	-			23,144
			33,681	19,297	23,655	-	76,633
D32	Dist. Plant Stn		31,473	21,351	27,403		80,227
D36	Dist. Plant	Lines	45,098	34,851	17,869		97,819
D40	Dist. Plant	S/E	12,554	12,158	5,399		30,111
			89,125	68,360	50,672	-	208,157
C23	Dist. Plant	Lines	30,066	23,234	11,913		65,212
C27	Dist. Plant	Services	4,669				4,669
C40	Dist. Plant	Meter Investment	3,078	1,867			4,944
C41	Dist. Plant	Meter Mtce.	-		2,736		2,736
			37,813	25,101	14,649	-	77,562
C10	Dist Serv	Cust Service - General	612	4,019	26,581	-	31,213
C11	Dist Serv	Cust Acct - Billings	531	2,769	22,101		25,402
C12	Dist Serv	Cust Acct - Collections	259	993	10,190		11,441
C13	Dist Serv	Marketing - R & D	36	118	1,207		1,360
C14	Dist Serv	Inspection	50	274	2,814		3,138
C15	Dist Serv	Meter Read	247	942	9,670		10,859
C30	Dist Serv	Hot Water Tank Program		254	-		254
			1,735	9,369	72,563	-	83,667
		Total Allocated Costs	613,215	304,530	468,604	396	1,386,745

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
DIRECTS							
C02	Generation	Diesel	1,812	4,332	4,577		10,721
E01	Generation	Export	30,161	12,135	171,097		213,393
			30,161	12,135	171,097	-	213,393
E01	Generation	SEP - GSM	467	158	320		946
E01	Generation	SEP - GSL 0-30kV	76	26	52		153
			543	184	372	-	1,099
D01	Generation	Curtailment (GSL 30-100)				(568)	(568)
D01	Generation	Curtailment (GSL > 100)				(5,900)	(5,900)
			-	-	-	(6,468)	(6,468)
E02	Transmission	Export	-	70	5,736		5,806
D04	Transmission	SEP - GSM	117	72	66		255
D04	Transmission	SEP - GSL 0-30kV	19	12	11		41
			136	83	77	-	296
C01	Distribution	Lighting	3,544	1,910	6,935		12,389
C01	Distribution	Diesel	153	228	393		774
			3,697	2,138	7,328	-	13,163
		Total Directs	36,349	18,941	189,188	(6,468)	238,010
	Total		649,564	323,471	657,792	(6,072)	1,624,755
	Generation		390,641	142,203	430,552	(6,072)	957,325
	Transmission		92,873	57,003	58,372	-	208,248
	Subtransmission		33,681	19,297	23,655	-	76,633
	Distribution Plant		130,635	95,599	72,649	-	298,882
	Distribution Services		1,735	9,369	72,563	-	83,667
			649,564	323,471	657,792	(6,072)	1,624,755
	Energy		388,829	137,871	425,975	396	953,072
	Demand		215,679	144,660	132,699	(6,468)	486,570
	Customer		45,057	40,939	99,117	-	185,113
			649,564	323,471	657,792	(6,072)	1,624,755

12 PERIOD WEIGHTED ENERGY TABLE

(E12 Generation)

PURPOSE

This table is used to allocate costs associated with the energy component within the Generation function.

METHOD

Table represents marginal cost ratios multiplied by twelve-period seasonal kW.h sales as measured at Generation (On-Peak, Off-Peak and Shoulder periods for each of the four seasons).

JUSTIFICATION

Generation costs are weighted by marginal cost factors to recognize the differential price of energy at various diurnal and seasonal periods.

AVERAGE WINTER AND SUMMER COINCIDENT PEAK DEMAND TABLE (MW)

(D14 Transmission)

PURPOSE

This table is used to allocate costs associated with the demand component of the Transmission function.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using load research data for 2005/06.

JUSTIFICATION

This allocation recognizes the integrated effects of export activity in both summer and winter seasons. These costs are allocated to each customer class in proportion to the contribution of each class to the maximum system peak demand. The contribution of each class to system peak includes the assignment of Distribution and Transmission losses.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D21 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with buildings, communication and general equipment of the demand component within the Subtransmission function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission level (>100 kV) do not share in any of the Subtransmission function costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses. Class non-coincident demands have been developed using historical data derived from load research data available from fiscal year ending March 31, 2006.

JUSTIFICATION

Subtransmission costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level (66 kV and 33 kV). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D22 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with substations and transformers of the demand component within the Subtransmission function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission level (>100 kV) do not share in any of the Subtransmission function costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses. Class non-coincident demands have been developed using historical data derived from load research data available from fiscal year ending March 31, 2006.

JUSTIFICATION

Subtransmission costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level (66 kV and 33 kV). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D23 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with the demand component of radial Transmission and Subtransmission lines within the Subtransmission function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission level (>100 kV) do not share in any of the Subtransmission function costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses. Class non-coincident demands have been developed using historical data derived from load research data available from fiscal year ending March 31, 2006.

JUSTIFICATION

Subtransmission costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level (66 kV and 33 kV). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D32 - Distribution Plant)

PURPOSE

This table is used to allocate costs associated with the demand component of Distribution stations and station transformers within the Distribution plant function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission or Subtransmission level (33 kV or greater) do not share in any of the Distribution costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses.

JUSTIFICATION

The demand component costs within the Distribution plant function are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the distribution level (25 kV and below). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D36 - Distribution Plant)

PURPOSE

These tables are used to allocate costs associated with the demand component of Distribution lines, farm lines and associated Distribution infrastructure within the Distribution plant function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission or Subtransmission level (33 kV or greater) do not share in any of the Distribution costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses.

JUSTIFICATION

The demand component costs within the Distribution plant function are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the distribution level (25 kV and below). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D40 - Distribution Plant)

PURPOSE

This table is used to allocate costs associated with the demand component of Distribution transformation. Classes receiving service at greater than 30 kV or with customer-owned transformation are excluded from the table.

METHOD

This table is based on the non-coincident peak demand of each class including losses.

JUSTIFICATION

The demand component costs within the Distribution plant function are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the distribution level (25 kV and below). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

WEIGHTED RATIO CUSTOMER SERVICE GENERAL TABLE

(C10 - Distribution Service)

PURPOSE

This table is used to allocate the general Customer Service costs within the Distribution services function.

METHOD

Customer classes are weighted according to total time spent by line departments on serving each customer class. An analysis was undertaken to estimate the efforts various departments devote to each customer class, which was weighted by the budget for each department. For example, Key Accounts Department spend all their time providing customer service to General Service Large customers and no time on Residential customer service and are weighted accordingly. Each class is allocated a portion of the non-specific customer costs based on their share of the total weighted table.

JUSTIFICATION

General costs associated with customer service and business activities are incurred relative to the customer service efforts devoted to each customer class, rather than the number of customers actually within each class.

WEIGHTED CUSTOMER COUNT TABLE - BILLING

(C11 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of billing costs.

METHOD

The allocation table represents the percentage of billing costs assignable to each rate class. An analysis was undertaken to determine the percentage of customer-related costs assignable to each class based upon a detailed billing study which was updated with forecast customer numbers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - COLLECTIONS

(C12 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of collection costs.

METHOD

The allocation table represents the percentage of collection costs assignable to each rate class. An analysis was undertaken to determine the percentage of customer-related costs assignable to each class based upon a detailed collection study which was updated with forecast customer numbers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

CUSTOMER COUNT TABLE - RESEARCH AND DEVELOPMENT

(C13 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of marketing - research and development costs.

METHOD

Number of customers adjusted for water heating and street/sentinel lighting

JUSTIFICATION

These costs are incurred relative to the number of customers that are being served. These costs are allocated to each customer class in proportion to the number of customers in each class.

WEIGHTED CUSTOMER COUNT TABLE - ELECTRICAL INSPECTIONS

(C14 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of electrical inspection costs.

METHOD

An analysis was undertaken to determine the percentage of customer-related costs assignable to each rate class based upon electrical inspection permit statistics. The results of this analysis are used to weight the forecasted number of customers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER READING

(C15 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of meter reading costs.

METHOD

The allocation table represents customers weighted by the relative frequency in which a meter is read by the utility. The results of this analysis are used to weight the forecast number of customers.

The relative frequency of meter readings by rate class is shown in the following table.

RATE CLASS	
Residential	
Standard	5
Seasonal	1
General Service - Small	
Demand	12
Non-Demand - Single Phase	5
Non-Demand - Three Phase	6
Seasonal	1
General Service Medium	12
General Service Large	
<30 kV	12
30 - 100 kV	12
>100 kV	12

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

CUSTOMER COUNT TABLE - DISTRIBUTION POLE AND WIRE

(C23 - Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with Distribution lines, farm lines, buildings and general equipment. Classes receiving service at greater than 30 kV are excluded from this table.

METHOD

The allocation table represents unweighted customers except for street lights, sentinel lights and flat rate water heating. No costs are allocated to sentinel lighting or flat rate water heating as this service has been provided by the primary rate class (i.e. Residential or General Service). Street lighting count reflects the number of taps into the distribution system that would be required if the lights were connected in a series through a relay.

JUSTIFICATION

Customer component costs are incurred in Distribution plant dependent upon the number of customers being served.

WEIGHTED CUSTOMER COUNT TABLE - SERVICES

(C27 - Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with service drops. Classes receiving service at greater than 30 kV, Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

Number of customers are weighted 5 x for General Service Small - 3 Phase, and 5 x for General Service Medium and General Service Large customers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER INVESTMENT

(C40- Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with meters and metering transformers. Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

An analysis of meter costs was undertaken to determine the relative costs for metering equipment by customer class and voltage level. The results of this analysis are used to weight the forecasted number of customers.

This table represents the number of customers weighted by the relative cost of metering equipment and the related cost of maintaining the metering equipment. No costs are allocated to non-metered services such as Street Lighting and Flat Rate Water Heating. The weighting factors for cost allocation are shown in the table below.

	WEIGHTING FACTOR
Residential	1.0
General Service Small	
Single Phase - Non-Demand	1.0
- Demand	14.0
Three Phase - Non-Demand	5.0
- Demand	23.0
General Service Medium	36.0
General Service Large	
0 - 30 kV	49.0
30 - 100 kV	224.0
>100 kV	233.0

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER MAINTENANCE

(C41- Distribution Plant)

PURPOSE

This table is used to allocate the customer portion relating to meter maintenance costs. Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

An analysis of meter maintenance costs was undertaken to determine the relative costs for meter maintenance by customer class. The results of this analysis are used to weight the forecasted number of customers.

This table represents the number of customers weighted by the relative cost of maintaining the metering equipment. No costs are allocated to non-metered services such as Street Lighting and Flat Rate Water Heating. The weighting factors for cost allocation are shown in the table below.

	WEIGHTING FACTOR
Residential	1.0
General Service Small	
Single Phase - Non-Demand	1.0
- Demand	155.0
Three Phase - Non-Demand	50.0
- Demand	105.0
General Service Medium	215.0
General Service Large	
0 - 30 kV	530.0
30 - 100 kV	530.0
>100 kV	530.0

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.