Q. **Reference: 2018 Cost of Service Methodology Review Report, p. 14 (25 pdf)**

Citation 1:

> Hydro plans to evaluate if it is practical to employ a peak allocation approach based on the percentage of load by class in the highest 50 hours of the winter season. Manitoba Hydro currently uses this approach. This analysis would provide additional information to evaluate the reasonableness of the current 1 CP allocation approach. Hydro plans to report to the Board on the analysis results in its next GRA.

Citation 2 (Appendix A, CAEC Report, page 13 (page 69 pdf)):

> An alternative might be to use a method applied at Manitoba Hydro, which makes use of the fifty highest demand hours of the winter. Such a measure requires recording and averaging much more data, but is likely to be stable and to capture behavior in the many hours associated with peak demand. Taking this approach to its logical conclusion, one might consider utilizing a marginal cost-based combined classification and allocation approach, which includes all hours, and uses marginal cost to value each hour. Section 3.3 discusses this approach.

Citation 3 (Appendix A, CAEC Report, page 23 (page 79 pdf)):

> Manitoba Hydro constitutes an interesting special case. Until recently the utility applied a “weighted energy” allocator to generation costs, which consists of marginal cost-based allocation of generation services. (Manitoba Hydro also utilized a variant of the process in allocating transmission costs.) In a recent COS methodology proceeding, the utility argued for retention of its weighted energy allocator. However, the Public Utilities Board of Manitoba (Manitoba Board) found that the allocator lacked elements of demand, a shortcoming that it felt was determinative. As a result, it required Manitoba Hydro to adopt a system load factor approach. The demand allocator that it recommended is a “winter CP” formulation in which usage in the fifty winter hours with the highest demand is to

Prospective Cost of Service Study

For Fiscal Year Ending

March 31, 2013

Manitoba Hydro

Cost of Service Department
July 2012

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

TABLE OF CONTENTS

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

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 cost 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. It also normalizes for water conditions which could have a significant impact on the results if based on current conditions.

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 only provides an approximation of the actual cost of serving a particular customer or group of customers within a customer class. 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. Because of the inexactness of a Cost of Service Study, a Zone of Reasonableness ("ZOR") is usually established within which Revenue to Cost Coverage ("RCC") ratios are targeted. At Manitoba Hydro the target Zone of Reasonableness is for RCC's to be within the range of 95 to 105 percent.

Cost of Service Review

Manitoba Hydro engaged Christensen Associates Energy Consultants ("CA") to perform a review of its Cost of Service Methodologies. Manitoba Hydro committed to undertake this review to confirm that Manitoba Hydro's cost of service methodologies are consistent with best practices and to address a number of issues that arose out of previous PUB proceedings. The report from CA largely endorsed the current cost of service methodology but also made several recommendations for enhancements.

Manitoba Hydro has prepared its 2012/13 Cost of Service Study ("PCOSS13") to reflect those changes it adopted from the Cost of Service Review (as discussed in MH's Response to that Review provided in Appendix 13.3) as follows:

1. Export Class

   PCOSS13 continues to recognize an Export Class. Additionally, PCOSS13 differentiates between Dependable and Opportunity export sales. Dependable export sales have been assigned a share of embedded generation and transmission costs as done previously; Opportunity exports have been assigned the costs of purchased power excluding wind purchases, with remaining opportunity sales in excess of power purchases attracting water rentals fees and variable hydraulic generation operating and maintenance ("O&M") only.

2. Thermal – Natural Gas Generation

   The cost of gas-fired thermal plants has been included in the Generation Pool for allocation to both the Dependable exports and the domestic classes.

3. Wind Power Purchase Costs

   The cost of wind power purchases is included in the generation pool for allocation to the Dependable Export and domestic classes in PCOSS13

4. Transmission Service from Radial Taps

   In PCOSS13 the cost of dedicated radial taps serving GSL>100 kV customers has been directly assigned to that class.

5. Distribution Plant – Service Voltage

In PCOSS13, the customer and demand factors for GSL 0-30kV used to allocate Distribution Poles and Wires costs have been reduced by 30% to recognize that these customers do not utilize Manitoba Hydro's secondary voltage distribution facilities.

PCOSS13

PCOSS13 has been prepared on the basis of the financial forecast for 2012/13 from IFF11-2 and follows the same methodology approach as reflected in PCOSS11. In addition, PCOSS13 has been prepared incorporating the test year conditions along with the changes in methodology flowing from the Cost of Service Review as discussed above. This comparison serves two purposes. It highlights the difference flowing from methodology changes. It also highlights the allocated cost difference between PCOSS13 and PCOSS11.

There are several matters impacting PCOSS13 that are noteworthy for discussion. These include MH's new deprecation study, Wuskwatim Generating Station, as well as Extraprovincial Revenues and are discussed below.

Depreciation Study

Manitoba Hydro completed a new depreciation study, with depreciation rates that resulted in a $38 million dollar reduction in forecast depreciation expense for 2012/13. These depreciation rates have been reflected in PCOSS13. The service life of subtransmission and distribution plant has been significantly extended, and resulted in the majority of the reduction in depreciation expense. The result is an increase in RCC for classes served from the Distribution system, and decrease in the RCC of classes served upstream of the Distribution system.

Wuskwatim Generating Station

The inclusion of Wuskwatim generating station in Manitoba Hydro's Financial Forecast and in PCOSS13 represents the first hydraulic generating station to go into service in over twenty years, at an average embedded cost of production higher than the existing generation assets. The impact on class RCC will vary depending on the relative proportion that generation costs represent in the total cost to serve each class. The increase in the average unit cost of generation will tend to increase the RCC for classes served from the Distribution system, such as the Residential class for whom generation costs represent 42% of the cost to serve. The increase in average generation costs will tend to decrease the RCC of classes served upstream of the Distribution system, such as the GSL >100 kV class for whom generation costs represent 82% of the cost to serve.

Extraprovincial Revenues

The reduction in Extraprovincial Revenues substantially attributable to lower projected export market prices does not impact class RCC's materially. This occurs because of the largely offsetting change in Contributions to Reserves (a component of Interest costs included in the PCOSS). The change in interest costs has the greatest impact on plant-intensive functions such as Generation and Transmission, while the reduction in net export has a uniform effect on the net cost of all functions excluding directly assigned cost. Impacts on RCCs will vary based on each class' relative use of each function and proportion of directly assigned costs, but will be considerably less than with similar revenue changes due to volume.

PCOSS Results

PCOSS13 has been prepared on the basis of IFF11-2 and includes revenues based on April 1, 2012 rates as approved in Order 32/12. As shown in the table below, the RCC's are provided for PCOSS11, and PCOSS13 (with and without methodology changes).

CUSTOMER CLASS	PCOSS11	PCOSS13 (no methodology change)	PCOSS13 (with methodology changes)
Residential	95.9%	98.1%	99.2%
GSS Non-Demand	104.8%	107.4%	107.6%
GSS Demand	103.8%	104.3%	103.7%
GSM	101.1%	100.8%	100.0%
GSL 0 – 30 kV	91.9%	92.0%	93.3%
GSL 30 – 100 kV	104.2%	98.2%	96.6%
GSL > 100 kV	112.6%	103.7%	100.5%
Area & Roadway Lighting	105.2%	101.4%	101.8%

Net Export Revenue

A summary of the costs assigned or allocated to the Export class is shown in the table below. PCOSS13 (with no methodology change) results in net export revenue of $(15.5) million to be allocated to domestic customers, and $64.0 million in PCOSS13 (including methodology changes).

	(million $) PCOSS13 (no methodology change)	(million $) PCOSS13 (with methodology changes)
Gross Export Revenue	341.9	341.9
Less:		
Uniform Rates	22.2	22.2
Affordable Energy Fund Expenditures	8.9	8.9
Trading Desk	5.0	5.0
MISO Fees	1.6	1.6
NEB Charges	0.7	0.7
Purchased Power and Transmission (excl wind)	103.0	103.0
Wind Purchases	65.1	n/a
Allocated G&T incl Water Rentals (dependable & opportunity)	150.8	n/a
Allocated G&T incl Water Rentals and Wind (dependable exports)	n/a	131.0
Assigned Water Rentals (opportunity exports)	n/a	5.1
Variable Hydraulic Generation O&M (opportunity exports)	n/a	0.5
Equals: Net Export Revenue	(15.5)	64.0

THIS PAGE LEFT BLANK

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

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 follow 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 (in 1992 the study changed from using historic embedded costs to forecast embedded costs).
- The study functionalizes utility costs into five main groups: Generation; Transmission; Subtransmission; Distribution Plant and Distribution Services (or Customer Service).
- The study allocates 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 allocates Customer Service costs in 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 classes in proportion to total allocated costs of all functions. This method was endorsed by the PUB in 2006. Previously the credit was allocated to classes on the same basis as allocated Generation and Transmission costs.

Cost of Service Review

Manitoba Hydro engaged Christensen Associates Energy Consultants ("CA") to perform a review of its Cost of Service Methodologies. Manitoba Hydro committed to undertake this review to confirm that Manitoba Hydro's cost of service methodologies are consistent with best practices and to address a number of issues that arose out of previous PUB proceedings. The report largely endorsed the current Cost of Service methodology, but also made several recommendations for enhancements.

PCOSS13 has been prepared on the basis of the financial forecast for 2012/13 from IFF11-2 and follows the same methodology approach as reflected in PCOSS11. In addition, PCOSS13 has been prepared incorporating the test year conditions along with the changes in methodology flowing from the Cost of Service Review as discussed above. This comparison serves two purposes. It highlights the difference flowing from methodology changes. It also highlights the allocated cost difference between PCOSS13 and PCOSS11.

The following changes in methodology are reflected in PCOSS13 (with methodology changes):

Export Class

PCOSS13 continues to recognize an Export Class. Additionally, PCOSS13 differentiates between Dependable and Opportunity export sales. Dependable export sales have been assigned a share of embedded generation and transmission costs as done previously; Opportunity exports have been assigned the costs of purchased power excluding wind purchases, with remaining opportunity sales in excess of power purchases attracting water rentals fees and variable hydraulic generation O&M only.

Distinction should be made between the cost assignment appropriate for long-term contract commitments made out of dependable resources, and that for short-term sales made on an "as available" basis. Opportunity exports are considered a residual from a long-term planning perspective, and are therefore assigned only the variable costs associated with serving these exports.

Thermal – Natural Gas Generation

The cost of gas-fired thermal plants has been included in the Generation Pool for allocation to both the Dependable exports and the Domestic classes. Although natural gas-fired generation is not required to support export sales in the median water conditions used in the PCOSS, on a probabilistic basis natural gas generation may support these sales during extreme conditions

Wind Power Purchase Costs

The energy from wind power purchases is blended into Manitoba Hydro's overall energy supply to provide firm energy to serve both domestic classes and dependable export sales. Manitoba Hydro agrees with CA's perspective that it is inappropriate to assign the entire cost to the export class and has included the cost of wind power purchases in the generation pool for allocation to the Dependable Export and Domestic classes.

Transmission Service from Radial Taps

The cost of dedicated radial taps serving GSL >100 kV customers has been directly assigned to that class in PCOSS13 (with methodology changes). In previous studies the cost of dedicated radial taps ineligible for inclusion in Manitoba Hydro's Open Access Transmission Tariff was included in the Subtransmission function. Manitoba Hydro agrees with CA's perspective that in the case of dedicated radial taps serving GSL >100 kV customers, the exclusion of these customers from these costs resulted in a slight understatement in the cost to serve those customers since they do not share subtransmission costs.

Distribution Plant – Service Voltage

As discussed in the Cost of Service Review, the customer and demand factors for GSL 0-30kV used to allocate Distribution Poles and Wires costs have been reduced by 30% to recognize that these customers do not utilize Manitoba Hydro's secondary voltage distribution facilities.

<u>The following assignment or allocations of costs are unchanged in PCOSS13:</u>

Assignment of Power Purchases and Transmission Service Fees

Non-wind purchased power costs and the costs associated with securing US transmission used to facilitate export sales have been directly assigned to the Export class consistent with past practice.

Assignment of 'Trading Desk' and MISO Fees

The 'Trading Desk', as well as MISO membership provides benefits to domestic customers by facilitating import purchases needed for dependable supply, and during periods of prolonged drought, or in the event of a major generation or transmission failure. Consequently, the portion of these costs that can be directly attributed to Manitoba Hydro's export sales activities has been directly assigned to the export class. The remaining 58% of the costs have been assigned to the domestic classes.

Assignment of DSM Costs

PCOSS13 assigns program costs to the customer classes in the same manner as carried out in PCOSS11. CA noted and Manitoba Hydro agrees that DSM is not driven by export sales and the costs should be assigned to the customer classes benefiting from the DSM programming. Assignment in PCOSS13 is based on class participation over ten years in order to match the capitalization and subsequent amortization of program costs, rather than a single year as used in PCOSS11.

Thermal Plant Costs - Coal

In accordance with climate change legislation, use of the Brandon Unit 5 coal generating station is limited to emergency use to serve domestic load or existing firm export contracts which expire by 2015. As Manitoba Hydro cannot dispatch coal-fired generation to support new export sales, CA recommended the costs be assigned to domestic classes only. All the fixed and variable costs of the unit have been assigned entirely to the domestic classes in this study.

Classification of Distribution Plant

The classification of Distribution poles and wires as partially demand-related and partially customer-related was endorsed by CA, and has been used in PCOSS13.

Allocation of Distribution Plant

PCOSS13 continues to allocate theses costs on the basis of class-NCP (Non-Coincident Peak) demand. CA endorsed the current method of allocating demand-related distribution plant cost on the basis of class-NCP, noting the treatment was common industry practice.

Affordable Energy Fund

The Affordable Energy Fund expenditures will continue to be treated as a policy-related first charge against net export revenue consistent with Manitoba Hydro's interpretation of the intent of Government of Manitoba's legislation creating the fund.

Uniform Rates Adjustment

Manitoba Hydro considers the adjustment a policy-related first charge on net export revenues, and has assigned the adjustment to the export class.

A&RL Weighting Factors

CA also reviewed and provided recommendation on the customer class weightings used for Area and Roadway Lighting ("A&RL") in the allocation of various customer-related costs. Manitoba Hydro accepts the recommendation in the CA report to give A&RL a zero-weight in the allocator for both 'Marketing R&D' and 'Collections', as an examination of the nature of the costs indicated that it is not appropriate to allocate any share of these costs to the A&RL class.

Treatment of Diesel Funding Agreement in PCOSS13

Allocation of export revenues in the PCOSS is based on total cost to serve in the diesel rate zone, as provided in the Diesel Funding Agreement between Manitoba Hydro, Aboriginal and Northern Development Canada (AANDC) and the four First Nations represented by Manitoba Keewatinook Ininew Okimowin (MKO). As such the total unreduced cost is reflected in the RCC Table in PCOSS13, while revenues for the Diesel class in the schedules are based upon variable costs.

The RCC calculated using the Diesel Cost of Service Study for 2011/12 is approximately 79% using revenues of $6.3 million and variable costs of $8.0 million. Note that revenue does not include allocated net export revenues, which are currently being applied against the accumulated deficit of approximately $4.1 million as at March 31, 2012. According to the terms of the Diesel Funding Agreement the deficit will be fully amortized by March 31, 2014.

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

SECTION B: SUMMARY RESULTS

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

PCOSS13 has been prepared on the basis of the financial forecast for 2012/13 from IFF11-2 and followed the same methodology approach as reflected in PCOSS11. PCOSS13 includes revenues based on April 1, 2012 rates as approved in Order 32/12. There are several key matters noteworthy for discussion. These include MH's new deprecation study, Wuskwatim Generating Station, Net Extra provincial Revenues, IFRS as well as Expected water flow conditions in IFF11-2 and are discussed below.

Depreciation Study

Manitoba Hydro completed a new depreciation study, with depreciation rates that will be implemented in two phases. The first phase, including new asset component groupings and updated services lives, is effective April 1, 2011. A second phase will implement IFRS compliant depreciation rates effective April 1, 2013.

The impact of the new rates effective April 1, 2011 is a $38 million dollar reduction in forecast depreciation expense for 2012/13. These depreciation rates have been reflected in PCOSS13. The service life of subtransmission and distribution plant has been significantly extended, and resulted in the majority of the reduction in depreciation expense. The result is an increase in RCC for classes served from the Distribution system, and decrease in the RCC of classes served upstream of the Distribution system.

Wuskwatim Generating Station

The inclusion of Wuskwatim generating station in MH's financial forecast and PCOSS13 represents the first hydraulic generating station to go into service in over twenty years, at an average embedded cost of production higher than the existing generation assets. The increase in the average unit cost of generation will tend to increase the RCC for classes served from the Distribution system, and decrease the RCC of classes served upstream of the Distribution system.

International Financial Reporting Standards (IFRS)

IFF11-2 assumes that Manitoba Hydro will transition to IFRS effective April 1, 2013. Therefore, the impacts of IFRS are not reflected in the 2012/13 test year used for PCOSS13.

Expected Water Flow Conditions

PCOSS13 has been prepared on the basis of the 2012/13 financial forecast from IFF11-2, which incorporates expected water flow conditions rather than the median flow water conditions normally used. Expected flows in this case are lower than under median conditions, which can be expected to result in a reduction in opportunity export sales. The effect of forecasting export revenues that are lower than the long term average is not expected to have a material impact to PCOSS13 incorporating methodology changes.

PCOSS13 Results

PCOSS13 incorporates the test year conditions, with and without the changes in methodology flowing from the Cost of Service Review. This comparison serves two purposes. It highlights the difference flowing from methodology changes. It also highlights the allocated cost difference between PCOSS13 and PCOSS11.

A summary of the RCC's are provided in the table below.

CUSTOMER CLASS	PCOSS11	PCOSS13 (no methodology change)	PCOSS13 (with methodology changes)
Residential	95.9%	98.1%	99.2%
GSS Non-Demand	104.8%	107.4%	107.6%
GSS Demand	103.8%	104.3%	103.7%
GSM	101.1%	100.8%	100.0%
GSL 0 – 30 kV	91.9%	92.0%	93.3%
GSL 30 – 100 kV	104.2%	98.2%	96.6%
GSL > 100 kV	112.6%	103.7%	100.5%
Area & Roadway Lighting	105.2%	101.4%	101.8%

The primary tables include:

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 outlines the customer class RCC. Schedule B7 provides the RCC impacts by class for each of the methodology changes reflected in PCOSS13. To determine these impacts, the changes are made cumulatively and the specific change may vary depending on the sequence in which the steps are performed;

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 kWh sales. The information in Schedules B2 and B5 are 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. Schedule B3 and B6 outlines the functional breakdown.

SCHEDULE B1

Revenue Cost Coverage Analysis – No Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2013
Revenue Cost Coverage Analysis

S UMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	557,672	554,168	(6,854)	547,314	98.1%
General Service - Small Non Demand	119,419	129,669	(1,416)	128,253	107.4%
General Service - Small Demand	117,946	124,443	(1,395)	123,048	104.3%
General Service - Medium	170,821	174,168	(2,041)	172,127	100.8%
General Service - Large 0 - 30kV	88,399	82,424	(1,056)	81,368	92.0%
General Service - Large 30-100kV*	42,838	42,593	(520)	42,072	98.2%
General Service - Large >100kV*	171,565	179,910	(2,051)	177,859	103.7%
*Includes Curtailment Customers					
SEP	1,004	894	-	894	89.0%
Area & Roadway Lighting	20,269	20,620	(75)	20,545	101.4%
Total General Consumers	1,289,932	1,308,889	(15,410)	1,293,479	100.3%
Diesel	9,476	6,047	(118)	5,929	62.6%
Export	357,379	341,851	15,528	357,379	100.0%
Total System	1,656,787	1,656,787	-	1,656,787	100.0%

SCHEDULE B2

Customer, Demand, Energy Cost Analysis – No Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2013
Customer, Demand, Energy Cost Analysis

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	121,550	480,996	21.06	206,199	0%	n/a	n/a	236,777	7,266,318	6.10	**
GS Small - Non Demand	24,520	53,714	38.04	39,922	0%	n/a	n/a	56,394	1,612,575	5.97	**
GS Small - Demand	8,596	12,297	58.25	43,735	37%	2,195	7.32	67,009	1,971,347	4.80	
General Service - Medium	7,259	1,938	312.13	63,344	87%	7,026	7.83	102,259	3,100,595	3.57	
General Service - Large <30kV	3,725	289	n/a	30,106	100%	4,148	8.16 *	55,624	1,721,592	3.23	
General Service - Large 30-100kV	2,596	40	n/a	9,698	100%	2,121	5.80 *	31,065	1,053,524	2.95	
General Service - Large >100kV	2,301	16	n/a	28,184	100%	8,511	3.58 *	143,131	4,857,207	2.95	
SEP	287	26	918.91	155	0%	n/a	n/a	562	25,600	2.80	**
Area & Roadway Lighting	15,484	153,444	8.41	2,313	0%	n/a	n/a	2,548	100,062	4.86	**
Total General Consumers	186,317	702,760		423,656		24,001		695,369	21,708,820		
Diesel	250	737	28.22	374	0%	n/a	n/a	8,970	13,463	69.41	**
Export	n/a	n/a	n/a	48,103	0%	n/a	n/a	309,275	7,340,000	4.87	***
Total System	186,567	703,497		472,133		24,001		1,013,615	29,062,282		

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

SCHEDULE B3

Functional Breakdown – No Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2013
Functional Breakdown

SUMMARY

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	564,526	236,777	41.9%	58,029	10.3%	41,329	7.3%	64,917	11.5%	163,474	29.0%
General Service - Small Non Demand	120,836	56,394	46.7%	13,200	10.9%	7,454	6.2%	16,934	14.0%	26,854	22.2%
General Service - Small Demand	119,341	67,009	56.1%	14,976	12.5%	8,022	6.7%	4,002	3.4%	25,332	21.2%
General Service - Medium	172,862	102,259	59.2%	23,327	13.5%	11,162	6.5%	6,144	3.6%	29,970	17.3%
General Service - Large <30kV	89,455	55,624	62.2%	12,523	14.0%	5,594	6.3%	3,467	3.9%	12,247	13.7%
General Service - Large 30-100kV	43,358	31,065	71.6%	6,395	14.7%	3,302	7.6%	2,514	5.8%	82	0.2%
General Service - Large >100kV	173,616	143,131	82.4%	28,184	16.2%	0	0.0%	2,267	1.3%	34	0.0%
SEP	1,004	562	56.0%	155	15.5%	0	0.0%	270	26.9%	16	1.6%
Area & Roadway Lighting	20,344	2,526	12.4%	415	2.0%	524	2.6%	504	2.5%	16,375	80.5%
Total General Consumers	1,305,342	695,347	53.3%	157,205	12.0%	77,386	5.9%	101,019	7.7%	274,384	21.0%
Diesel	9,594	8,970	93.5%	0	0.0%	0	0.0%	0	0.0%	624	6.5%
Export	357,379	309,275	86.5%	48,103	13.5%	0	0.0%	0	0.0%	0	0.0%
Total System	1,672,314	1,013,593	60.6%	205,308	12.3%	77,386	4.6%	101,019	6.0%	275,008	16.4%

SCHEDULE B4

Revenue Cost Coverage Analysis – With Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2013
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	586,783	554,168	27,958	582,126	99.2%
General Service - Small Non Demand	125,862	129,669	5,798	135,468	107.6%
General Service - Small Demand	125,560	124,443	5,770	130,213	103.7%
General Service - Medium	182,671	174,168	8,478	182,646	100.0%
General Service - Large 0 - 30kV	92,939	82,424	4,311	86,735	93.3%
General Service - Large 30-100kV*	46,358	42,593	2,186	44,779	96.6%
General Service - Large >100kV*	187,697	179,910	8,714	188,625	100.5%
*Includes Curtailment Customers					
SEP	1,004	894	-	894	89.0%
Area & Roadway Lighting	20,563	20,620	306	20,926	101.8%
Total General Consumers	1,369,438	1,308,889	63,521	1,372,410	100.2%
Diesel	9,476	6,047	457	6,504	68.6%
Export	277,873	341,851	(63,978)	277,873	100.0%
Total System	1,656,787	1,656,787	-	1,656,787	100.0%

SCHEDULE B5

Customer, Demand, Energy Cost Analysis – With Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2013
Customer, Demand, Energy Cost Analysis

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	114,272	480,996	19.80	201,851	0%	n/a	n/a	242,702	7,266,318	6.12	**
GS Small - Non Demand	23,051	53,714	35.76	39,309	0%	n/a	n/a	57,703	1,612,575	6.02	**
GS Small - Demand	8,081	12,297	54.76	43,124	37%	2,195	7.22	68,585	1,971,347	4.86	
General Service - Medium	6,824	1,938	293.42	62,650	87%	7,026	7.75	104,719	3,100,595	3.64	
General Service - Large <30kV	3,494	289	n/a	28,167	100%	4,148	7.63 *	56,967	1,721,592	3.31	
General Service - Large 30-100kV	2,440	40	n/a	9,893	100%	2,121	5.81 *	31,840	1,053,524	3.02	
General Service - Large >100kV	2,163	16	n/a	30,172	100%	8,511	3.80 *	146,648	4,857,207	3.02	
SEP	287	26	918.91	155	0%	n/a	n/a	562	25,600	2.80	**
Area & Roadway Lighting	15,408	153,444	8.37	2,237	0%	n/a	n/a	2,613	100,062	4.85	**
Total General Consumers	176,019	702,760		417,559		24,001		712,339	21,708,820		
Diesel	235	737	26.53	352	0%	n/a	n/a	8,432	13,463	65.25	**
Export	n/a	n/a	n/a	27,851	0%	n/a	n/a	250,021	7,340,000	3.79	***
Total System	176,254	703,497		445,762		24,001		970,793	29,062,282		

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

SCHEDULE B6

Functional Breakdown – With Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2013
Functional Breakdown

SUMMARY

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	558,825	242,702	43.4%	61,673	11.0%	38,741	6.9%	61,026	10.9%	154,683	27.7%
General Service - Small Non Demand	120,064	57,703	48.1%	14,029	11.7%	6,987	5.8%	15,919	13.3%	25,426	21.2%
General Service - Small Demand	119,791	68,585	57.3%	15,916	13.3%	7,520	6.3%	3,762	3.1%	24,008	20.0%
General Service - Medium	174,193	104,719	60.1%	24,791	14.2%	10,463	6.0%	5,776	3.3%	28,444	16.3%
General Service - Large <30kV	88,628	56,967	64.3%	13,310	15.0%	5,244	5.9%	3,259	3.7%	9,848	11.1%
General Service - Large 30-100kV	44,172	31,840	72.1%	6,797	15.4%	3,096	7.0%	2,364	5.4%	77	0.2%
General Service - Large >100kV	178,983	146,648	81.9%	30,172	16.9%	0	0.0%	2,131	1.2%	32	0.0%
SEP	1,004	562	56.0%	155	15.5%	0	0.0%	270	26.9%	16	1.6%
Area & Roadway Lighting	20,257	2,704	13.3%	461	2.3%	512	2.5%	495	2.4%	16,085	79.4%
Total General Consumers	1,305,917	712,430	54.6%	167,304	12.8%	72,562	5.6%	95,002	7.3%	258,618	19.8%
Diesel	9,019	8,432	93.5%	0	0.0%	0	0.0%	0	0.0%	587	6.5%
Export	277,873	250,021	90.0%	27,851	10.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,592,809	970,884	61.0%	195,156	12.3%	72,562	4.6%	95,002	6.0%	259,204	16.3%

SCHEDULE B7
RCC Impact of Methodology Changes

PCOSS13 Variance Analysis
Comparison of PCOSS13 with and without Methodology Changes

Customer Class	RCC% PCOSS13 (no Methodology Change)	Incremental Change in RCC: High Voltage Radial Taps	Secondary Distribution - GSL 0-30kV	Wind Purchases in Generation Pool	NG Thermal Plant in Generation Pool	Differentiate Dependable & Opportunity Export	Cummulative Impact	RCC% PCOSS13 (with Methodology Change)
Residential	**98.1%**	0.1%	-0.2%	0.6%	-0.1%	0.7%	1.1%	**99.2%**
GSS ND	**107.4%**	0.0%	-0.2%	0.3%	0.0%	0.1%	0.2%	**107.6%**
GSS Demand	**104.3%**	0.0%	-0.1%	-0.2%	0.0%	-0.3%	-0.6%	**103.7%**
GSM	**100.8%**	0.0%	-0.2%	-0.3%	0.1%	-0.4%	-0.8%	**100.0%**
GSL 0 - 30kV	**92.0%**	0.1%	1.8%	-0.3%	0.1%	-0.4%	1.3%	**93.3%**
GSL 30-100kV*	**98.2%**	0.0%	0.0%	-0.9%	0.2%	-0.9%	-1.6%	**96.6%**
GSL >100kV*	**103.7%**	-0.2%	0.0%	-1.6%	0.2%	-1.6%	-3.2%	**100.5%**
*Incl Curtailable								
SEP	**89.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**89.0%**
A&RL	**101.4%**	0.0%	-0.1%	0.2%	-0.1%	0.4%	0.4%	**101.8%**
Total	**100.3%**	0.0%	0.0%	-0.1%	0.1%	-0.1%	-0.1%	**100.2%**
Diesel	**62.6%**	0.0%	0.0%	2.8%	-0.4%	3.6%	6.0%	**68.6%**
Total System		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	

Net Export Revenue

PCOSS13 results in net export revenue of $(15.5) million to be allocated to domestic customers, and $64.0 million in PCOSS13 including methodology changes. A summary of the costs assigned or allocated to the Export class is shown in the table below:

	(million $) PCOSS13 (no methodology change)	**(million $) PCOSS13 (with methodology changes)**
Gross Export Revenue	341.9	341.9
Less:		
Uniform Rates	22.2	22.2
Affordable Energy Fund Expenditures	8.9	8.9
Trading Desk	5.0	5.0
MISO Fees	1.6	1.6
NEB Charges	0.7	0.7
Purchased Power and Transmission (excl wind)	103.0	103.0
Wind Purchases	65.1	n/a
Allocated G&T incl Water Rentals (dependable & opportunity)	150.8	n/a
Allocated G&T incl Water Rentals and Wind (dependable exports)	n/a	131.0
Assigned Water Rentals (opportunity exports)	n/a	5.1
Variable Hydraulic Generation O&M (opportunity exports)	n/a	0.5
Equals: Net Export Revenue	(15.5)	64.0

SECTION C: FUNCTIONALIZATION AND CLASSIFICATION METHODS

Organization and Preparation of Forecast Data

This Section provides a basic review of the approaches taken to organize Manitoba Hydro's 2012/13 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 E. 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 costs according to functions performed by the electric system. Manitoba Hydro has defined its functional levels as follows:

- 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.

- 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 PCOSS13 (no methodology changes). The cost of dedicated radial transmission facilities greater than 100 kV are directly assigned in the version of PCOSS13 (with methodology changes). 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.

- Ancillary Services Function – Ancillary Services include 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 to load while maintaining reliable operation of the Transmission provider's electrical system. A complete description of all ancillary services offered can be found in the "Functionalization and Classification of Capital Related Costs" section that follows. The costs shown for Ancillary Services in the PCOSS are those of the Scheduling, System Control and Dispatch Service only. Although the costs of this service are functionalized separately, they are included with Transmission for the purpose of allocation.

- 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.

- 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.

- 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 – The process of classifying functionalized costs 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] As based on Business Process Synchronization Unit ("BPSU") breakdown in SAP.

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

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.

- 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.

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

- 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.

<u>Functionalization and Classification Process</u>

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.

<u>Functionalization and Classification of Capital Related Costs</u>

In the preparation of the PCOSS the base year gross investment, that being actual plant in-service as of March 31, 2011, is first functionalized.

Functionalized gross plant investment for 2011 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 are functionalized as Generation, with the exception of Dorsey Station which is functionalized as Transmission. AC substations are functionalized as Transmission, Subtransmission or Distribution. An analysis of voltage levels, functions, current use, and related books and records of the company, is used to determine the functionalization of the numerous AC substations. 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.

As noted previously Ancillary Services are items that were formerly bundled within the Generation and Transmission function. Separation of these components is done through analysis of individual Generation and Transmission asset components.

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 from the Transmission provider:

- Scheduling, System Control and Dispatch Service – Required to schedule the movement of power from, to or within a control area;
- Reactive Supply and Voltage Control from Generation Source Service – Required to maintain Transmission voltages within acceptable limits.

The remaining four other Ancillary Services can be procured from the service provider, self supplied, or purchased from a third party:

- 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;
- Energy Imbalance Service – Provided when differences occur between scheduled and actual delivery of energy to a load over a single hour;
- Operating Reserve – Spinning Service – Needed to serve load immediately in the event of a system contingency;

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

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

Communication facilities and equipment are functionalized as 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"). Depreciation costs for 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 and domestic item additions. The domestic items consist of non-blanket items (facilities specifically identified) and blanket items (facilities broadly identified). Capital items consist of gross additions, salvage material and capital contributions. The functionalization of forecast salvage material and capital contributions follows the same methodology and is treated consistently with the functionalization of gross additions with the exception of the assignment of capital contributions for the Diesel Rate Zone. These contributions are deducted from those functionalized as distribution lines. 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. 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 nets salvage labour and expense together by facility. 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, 2013.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year ending March 31, 2013. Accumulated depreciation for the building and general equipment asset classes are prorated based upon functionalized gross investment (opening balance). Accumulated depreciation for the remaining asset classes are functionalized on the same basis used to functionalize the gross investment.

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 2013.

Depreciation expense, both direct facility depreciation and allocated administrative depreciation, is separated from operating costs. The Corporation periodically undertakes a depreciation study to ensure that amortization of assets is commensurate with the actual life of a particular asset. The last such review was in fiscal year 2010/11; these revised rates are reflected in the PCOSS13. 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 2011/12 and 2012/13 with adjustments for net regulated/intangible 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, 2013 (gross investment less accumulated depreciation) adjusted to include net regulated/intangible expenses which is used to functionalize forecast capital tax assessment. The functionalization of the forecast capital tax assessment for 2012/13 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 include classification of distribution costs into customer and demand components. This approach used to classify distribution facilities is 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.

Class revenue includes an adjustment to offset any revenue reduction that resulted from implementation of the uniform rates legislation that equalized northern, urban and rural rates throughout the province. The adjustment is necessary to ensure that the cost of implementing uniform rates is broadly shared, and not solely borne by the affected classes' former Zone 1 customers through degradation of the class RCC. The class revenue reduction percentages were calculated by dividing the total revenue for each class after uniform rates by that prior to the adoption of uniform rates. The reduction percentages are applied to the forecast revenue in the study to determine the adjusted revenue for the class. While the percentages are based on a one-time calculation and are constant, the forecast revenue will vary resulting in a change of the magnitude of the adjustment between studies. In PCOSS13 the revenue adjustment is $22 million, with the offset charged against net export revenue as per PUB Order 101/04.

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:

CLASS	TOTAL
Residential	$ 3,062,733
General Service Small-Non-Demand	$ 1,483,069
General Service Small-Demand	$ 1,821,592
General Service Medium	$ 1,937,762
General Service Large:	
0 - 30 kV	$1,049,865
30 - 100 kV	$ 523,451
> 100 kV	$ 2,603,826
Total DSM	**$12,482,297**

The accrual adjustment represents any forecast 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 general service large (>30 kV) 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 street lighting and general service large (>30 kV) customers. Although some of this revenue would apply to the general service large customers 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.

SCHEDULE C1

Functionalization of Gross Investment March 31, 2011

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
MARCH 31, 2011

ASSET CLASS	TOTAL GROSS INVESTMENT	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	4,861,712,041	4,861,712,041								
-Thermal	438,062,495	438,062,495								
DIESEL	47,836,661									47,836,661
SUBSTATION	1,249,652,835	16,288,409	401,144,113	91,497,443	221,821,317	504,376,685		14,524,868		
- HVDC	1,218,004,734	586,539,724	631,465,010							
TRANSMISSION	602,765,811		302,598,784	126,831,693	173,335,334					
- HVDC	192,946,343	192,946,343								
DISTRIBUTION	2,247,341,995					2,092,305,306			151,667,021	3,369,668
SUBTRANSMISSION	276,497,731				264,981,017	11,516,714				
TRANSFORMERS										
- SUBSTATION	21,199,631	279,573	6,885,203	1,570,454	3,807,322	8,657,079				
- DISTRIBUTION	11,812,938					11,812,938				
METERS	46,849,241					46,849,241				
BUILDINGS	443,897,600	186,983,237	55,605,411	9,110,849	27,697,787	78,172,535	79,023,085		6,682,520	622,176
COMMUNICATION	395,068,196	90,410,805	33,437,938	10,183,176	71,073,506	95,401,328		94,561,443		
GENERAL EQUIPMENT	165,046,500	69,620,211	20,703,784	3,392,278	10,312,827	29,106,291	29,422,979		2,488,129	
SUBTOTAL	12,218,694,752	6,442,842,838	1,451,840,244	242,585,894	773,029,111	2,878,198,116	108,446,064	109,086,311	160,837,670	51,828,505
MOTOR VEHICLES	173,652,840									
TOTAL FIXED ASSETS	12,392,347,592	6,442,842,838	1,451,840,244	242,585,894	773,029,111	2,878,198,116	108,446,064	109,086,311	160,837,670	51,828,505

SCHEDULE C2
Functionalization of Gross Investment Forecast

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2013

			Transmission		Sub-	Distribution			DIRECT ALLOCATIONS	
Asset Class	Total	Generation	Domestic	Export	Transmission	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	6,589,069,279	6,589,069,279	-	-	-	-	-	-	-	-
-Thermal	446,661,101	446,661,101	-	-	-	-	-	-	-	-
DIESEL	48,361,693	-	-	-	-	-	-	-	-	48,361,693
SUBSTATION	1,584,361,511	17,324,080	604,614,102	92,199,900	265,062,466	590,636,095	-	14,524,868	-	-
- HVDC	1,298,513,089	613,143,287	685,369,802	-	-	-	-	-	-	-
TRANSMISSION	795,750,253	-	470,488,910	148,721,440	176,539,903	-	-	-	-	-
- HVDC	192,946,343	192,946,343	-	-	-	-	-	-	-	-
DISTRIBUTION	2,520,858,688	-	-	-	-	2,355,395,173	-	-	162,093,847	3,369,668
SUBTRANSMISSION	314,664,343	-	-	-	303,147,629	11,516,714	-	-	-	-
TRANSFORMERS										
- SUBSTATION	21,199,631	279,573	6,885,203	1,570,454	3,807,322	8,657,079	-	-	-	-
- DISTRIBUTION	11,812,938	-	-	-	-	11,812,938	-	-	-	-
METERS	52,253,746	-	-	-	-	52,253,746	-	-	-	-
BUILDINGS	457,372,587	192,667,280	57,295,742	9,387,806	28,539,764	80,548,877	81,425,282	-	6,885,660	622,176
COMMUNICATION	441,517,995	101,040,777	37,369,374	11,380,454	79,429,912	106,618,056	-	105,679,422	-	-
GENERAL EQUIPMENT	232,787,505	98,194,844	29,201,359	4,784,591	14,545,582	41,052,557	41,499,226	-	3,509,347	-
SUBTOTAL	15,008,130,702	8,251,326,563	1,891,224,494	268,044,646	871,072,577	3,258,491,233	122,924,508	120,204,290	172,488,854	52,353,537
MOTOR VEHICLES	204,199,483									
TOTAL FIXED ASSETS	15,212,330,184	8,251,326,563	1,891,224,494	268,044,646	871,072,577	3,258,491,233	122,924,508	120,204,290	172,488,854	52,353,537

SCHEDULE C3
Functionalization of Accumulated Depreciation

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF ACCUMULATED DEPRECIATION
FORECAST YEAR ENDING MARCH 31, 2013

			Transmission		Sub	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Accum Depn by Asset Class	Generation	Domestic	Export	Trans	Plant	Services	Services	Lighting	Diesel
GENERATION	1,767,546,201	1,767,546,201	-	-	-	-	-	-	-	-
-Thermal	238,958,724	238,958,724	-	-	-	-	-	-	-	-
DIESEL	39,182,656	-	-	-	-	-	-	-	-	39,182,656
SUBSTATION	570,132,176	11,694,744	174,444,924	31,400,451	115,790,296	223,251,447	-	13,550,313	-	-
- HVDC	754,807,995	371,604,378	383,203,617	-	-	-	-	-	-	-
TRANSMISSION	231,504,935	-	124,004,026	54,052,626	53,448,283	-	-	-	-	-
- HVDC	83,317,284	83,317,284	-	-	-	-	-	-	-	-
DISTRIBUTION	1,021,471,070	-	-	-	-	934,503,773	-	-	84,779,242	2,188,055
SUBTRANSMISSION	115,959,467	-	-	-	110,985,106	4,974,361	-	-	-	-
TRANSFORMERS										
- SUBSTATION	11,656,245	252,012	3,578,310	667,305	2,445,119	4,713,499	-	-	-	-
- DISTRIBUTION	3,129,638	-	-	-	-	3,129,638	-	-	-	-
METERS	23,196,114	-	-	-	-	23,196,114	-	-	-	-
BUILDINGS	54,456,553	22,888,106	6,806,506	1,115,234	3,390,410	9,568,886	9,673,000	-	817,989	196,421
COMMUNICATION	163,899,459	40,882,554	12,992,252	3,548,379	29,244,998	33,243,076	-	43,988,199	-	-
GENERAL EQUIPMENT	97,399,127	41,085,075	12,217,954	2,001,890	6,085,924	17,176,537	17,363,425	-	1,468,323	-
SUBTOTAL	5,176,617,644	2,578,229,078	717,247,590	92,785,885	321,390,136	1,253,757,331	27,036,425	57,538,512	87,065,555	41,567,132
MOTOR VEHICLES	80,427,648									
TOTAL ACCUM DEPRECIATION	5,257,045,292	2,578,229,078	717,247,590	92,785,885	321,390,136	1,253,757,331	27,036,425	57,538,512	87,065,555	41,567,132

SCHEDULE C4

Functionalization of Capital Contributions Unamortized Balance

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
UNAMORTIZED BALANCE
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Unamortized Capital Contribution	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	475,745	475,745	-	-	-	-	-	-	-	-
-Thermal	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-
SUBSTATION	24,221,806	-	3,588,971	-	2,133,393	18,499,442	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
TRANSMISSION	63,057,025	-	1,903,194	316,000	60,837,832	-	-	-	-	-
- HVDC	51,851	51,851	-	-	-	-	-	-	-	-
DISTRIBUTION	201,139,858	-	-	-	-	172,688,424	-	-	28,119,697	331,737
SUBTRANSMISSION	12,242,531	-	-	-	12,242,531	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	-	-	-	-	-	-	-	-	-	-
BUILDINGS	-	-	-	-	-	-	-	-	-	-
COMMUNICATION	281,094	37,438	140,541	37,377	15,009	50,729	-	-	-	-
GENERAL EQUIPMENT	186,684	186,684	-	-	-	-	-	-	-	-
SUBTOTAL	301,656,595	751,717	5,632,707	353,376	75,228,765	191,238,595	-	-	28,119,697	331,737
MOTOR VEHICLES	-									
TOTAL UNAMORTIZED CONTRIBS	301,656,595	751,717	5,632,707	353,376	75,228,765	191,238,595	-	-	28,119,697	331,737

SCHEDULE C5
Functionalization of Capital Contributions Annual Amortization

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
ANNUAL AMORITIZATION
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Annual Amortization Contribution	Generation	Transmission Domestic	Transmission Export	Sub - Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	2,492	2,492								
-Thermal	-									
DIESEL	-									
SUBSTATION	1,235,339		164,695		85,291	985,352				
- HVDC	-									
TRANSMISSION	1,356,006		30,197	4,741	1,321,068					
- HVDC	820	820								
DISTRIBUTION	4,959,027					3,413,979			1,511,700	33,348
SUBTRANSMISSION	365,969				365,969					
TRANSFORMERS										
- SUBSTATION	-									
- DISTRIBUTION	-									
METERS	-									
BUILDINGS	-									
COMMUNICATION	13,966	1,860	6,983	1,857	746	2,520				
GENERAL EQUIPMENT	18,226	18,226								
SUBTOTAL	7,951,844	23,398	201,875	6,598	1,773,074	4,401,852	-	-	1,511,700	33,348
MOTOR VEHICLES	-									
TOTAL ANNUAL AMORT.	7,951,844	23,398	201,875	6,598	1,773,074	4,401,852	-	-	1,511,700	33,348

SCHEDULE C6
Functionalization of Depreciation Costs

2013 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2013
Functionalization of Operating Costs

SCC Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancilary Services	Diesel	Street Lighting	Exports
Common Generation Costs	34,566,340	29,934,220								4,632,120
Generating Station Costs	46,943,036	46,943,036								-
Other Generation Related Costs	996,139	996,139	-	-	-	-		-	-	
Dedicated Gen. Facilities	47,939,175	47,939,175						-	-	-
Hydraulic Generating Stations	150,447,016	150,447,016								
Other Hydraulic Generation Related Cost	17,937,388	17,937,388								
Hydraulic Generation Costs	168,384,405	168,384,405								
Thermal Generating Station	33,616,822	33,616,822								-
Non-Dedicated Gen. Facilities	202,001,227	202,001,227								-
Generation Facilities Costs	249,940,402	249,940,402						-	-	-
Purchased Power/Export Costs	168,831,000	-								168,831,000
Generation Facilities & Costs	***453,337,742***	***279,874,622***						-	-	***173,463,120***
Common Trans. Costs/Revenues	27,116,987	494,177	21,360,973	3,648,087						1,613,750
Generation Switching Stations	2,511,681	-	2,511,681							
HVDC & Collector Facilities	40,907,494	22,960,235	17,947,259							
Networked AC Facilities	4,097,814	-	4,097,814							
Generation Access Transmission	47,516,989	22,960,235	24,556,754							
Regional Networked Trans.	1,770,026	-	1,770,026	-	-					
Transmission Common	15,125,857	-	14,453,144	619,358	-	-	53,355	-		
Transmission Facilities/Costs	***91,529,860***	***23,454,412***	***62,140,898***	***4,267,445***	-	-	***53,355***	-		***1,613,750***
Common Subtransmission Costs	6,314,837	-	-	6,314,837						
Subtrans. Facilities & Costs	***31,357,499***	-	-	***22,032,156***	***9,325,342***	-		-	-	-
Dist. Facilities & Costs	***77,160,131***	-	-	-	***70,118,748***	-		-	***7,041,383***	-
Customer Service Costs	***83,266,761***	-	-	-	-	***83,266,761***		-	-	-
Isolated Diesel Facilities	***7,107,920***	-	-	-	-	-		***7,107,920***		
Communication & Control System	***12,209,467***	***6,000,721***	-	***2,379,929***	***1,103,068***	-	***2,725,748***	-	-	-
	762,566,000	**311,939,439**	**63,798,781**	**29,185,206**	**82,370,535**	**83,266,761**	**2,779,103**	**7,107,920**	**7,041,383**	**175,076,870**

SCHEDULE C7
Functionalization of Net Investment

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF NET INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Net Investment	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	4,821,047,333	4,821,047,333	-	-	-	-	-	-	-	-
-Thermal	207,702,377	207,702,377	-	-	-	-	-	-	-	-
DIESEL	9,179,037	-	-	-	-	-	-	-	-	9,179,037
SUBSTATION	990,007,529	5,629,336	426,580,206	60,799,449	147,138,778	348,885,205	-	974,555	-	-
- HVDC	543,705,094	241,538,910	302,166,184	-	-	-	-	-	-	-
TRANSMISSION	501,188,292	-	344,581,690	94,352,815	62,253,787	-	-	-	-	-
- HVDC	109,577,208	109,577,208	-	-						
DISTRIBUTION	1,298,247,760	-	-	-	-	1,248,202,976	-	-	49,194,908	849,876
SUBTRANSMISSION	186,462,345	-	-	-	179,919,992	6,542,353	-	-	-	-
TRANSFORMERS										
- SUBSTATION	9,543,386	27,561	3,306,893	903,149	1,362,203	3,943,579	-	-	-	-
- DISTRIBUTION	8,683,300	-	-	-	-	8,683,300	-	-	-	-
METERS	29,057,632	-	-	-	-	29,057,632	-	-	-	-
BUILDINGS	402,916,034	169,779,173	50,489,236	8,272,572	25,149,353	70,979,991	71,752,283	-	6,067,671	425,755
COMMUNICATION	277,337,442	60,120,785	24,236,581	7,794,699	50,169,904	73,324,251	-	61,691,223	-	-
GENERAL EQUIPMENT	135,201,694	56,923,085	16,983,406	2,782,701	8,459,658	23,876,020	24,135,801	-	2,041,023	-
SUBTOTAL	9,529,856,463	5,672,345,767	1,168,344,197	174,905,385	474,453,676	1,813,495,307	95,888,083	62,665,778	57,303,602	10,454,667
MOTOR VEHICLES	123,771,834									
TOTAL NET INVESTMENT	9,653,628,298	5,672,345,767	1,168,344,197	174,905,385	474,453,676	1,813,495,307	95,888,083	62,665,778	57,303,602	10,454,667

SCHEDULE C8

Functionalization of Rate Base Investment

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2013

			Transmission			Distribution			DIRECT ALLOCATIONS	
Asset Class	Rate Base Investment	Generation	Domestic	Export	Sub-Transmission	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	4,575,185,812	4,575,185,812	-	-	-	-	-	-	-	-
-Thermal	212,606,521	212,606,521	-	-	-	-	-	-	-	-
DIESEL	14,199,030	-	-	-	-	-	-	-	-	14,199,030
SUBSTATION	960,526,461	5,306,005	416,572,279	61,802,742	133,481,611	342,325,058	-	1,038,766	-	-
- HVDC	541,595,018	243,884,992	297,710,025	-	-	-	-	-	-	-
TRANSMISSION	509,012,587	-	351,860,199	89,857,463	67,294,925	-	-	-	-	-
- HVDC	111,101,553	111,101,553	-	-	-	-	-	-	-	-
DISTRIBUTION	1,294,528,852	-	-	-	-	1,242,483,401	-	-	51,179,548	865,903
SUBTRANSMISSION	185,212,157	-	-	-	178,413,811	6,798,346	-	-	-	-
TRANSFORMERS										
- SUBSTATION	9,882,552	32,034	3,417,047	928,274	1,423,115	4,082,081	-	-	-	-
- DISTRIBUTION	8,858,955	-	-	-	-	8,858,955	-	-	-	-
METERS	30,348,334	-	-	-	-	30,348,334	-	-	-	-
BUILDINGS	402,289,805	169,513,072	50,410,102	8,259,606	25,109,936	70,868,741	71,639,823	-	6,058,161	430,365
COMMUNICATION	281,589,232	61,094,469	24,593,545	7,903,543	50,935,693	74,351,402	-	62,710,581	-	-
GENERAL EQUIPMENT	215,066,750	90,606,638	27,002,991	4,424,393	13,450,546	37,961,994	38,375,036	-	3,245,152	-
SUBTOTAL	9,352,003,620	5,469,331,095	1,171,566,190	173,176,021	470,109,636	1,818,078,312	110,014,859	63,749,347	60,482,862	15,495,298
MOTOR VEHICLES	120,491,391									
Total Rate Base Investment	9,472,495,011	5,469,331,095	1,171,566,190	173,176,021	470,109,636	1,818,078,312	110,014,859	63,749,347	60,482,862	15,495,298

SCHEDULE C9

Functionalization of Interest Expense & Reserve Contribution

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Interest & Reserve Expense	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	207,469,822	207,469,822	-	-	-	-	-	-	-	-
-THERMAL	9,641,015	9,641,015	-	-	-	-	-	-	-	-
DIESEL	643,880	-	-	-	-	-	-	-	-	643,880
SUBSTATION	43,556,756	240,610	18,890,200	2,802,554	6,052,958	15,523,330	-	47,105	-	-
- HVDC	24,559,576	11,059,393	13,500,183	-	-	-	-	-	-	-
TRANSMISSION	23,082,068	-	15,955,718	4,074,744	3,051,606	-	-	-	-	-
- HVDC	5,038,095	5,038,095	-	-	-	-	-	-	-	-
DISTRIBUTION	58,702,680	-	-	-	-	56,342,588	-	-	2,320,826	39,266
SUBTRANSMISSION	8,398,770	-	-	-	8,090,487	308,283	-	-	-	-
TRANSFORMERS										
- SUBSTATION	448,142	1,453	154,952	42,094	64,534	185,109	-	-	-	-
- DISTRIBUTION	401,725	-	-	-	-	401,725	-	-	-	-
METERS	1,376,198	-	-	-	-	1,376,198	-	-	-	-
BUILDINGS	18,242,537	7,686,867	2,285,934	374,546	1,138,654	3,213,667	3,248,633	-	274,718	19,516
COMMUNICATION	12,769,157	2,770,436	1,115,237	358,400	2,309,768	3,371,595	-	2,843,721	-	-
GENERAL EQUIPMENT	9,752,579	4,108,717	1,224,498	200,632	609,939	1,721,453	1,740,183	-	147,157	-
SUBTOTAL	424,083,000	248,016,407	53,126,723	7,852,970	21,317,946	82,443,948	4,988,817	2,890,826	2,742,701	702,661
MOTOR VEHICLES	-									
Total Interest Exp Allocated	424,083,000	248,016,407	53,126,723	7,852,970	21,317,946	82,443,948	4,988,817	2,890,826	2,742,701	702,661

SCHEDULE C10

Functionalization of Rate Base for Capital Tax

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Rate Based for Capital Tax	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	5,030,404,673	5,030,404,673	-	-	-	-	-	-	-	-
-THERMAL	207,702,377	207,702,377	-	-	-	-	-	-	-	-
DIESEL	13,320,042	-	-	-	-	-	-	-	-	13,320,042
SUBSTATION	990,820,796	5,639,936	426,841,269	60,858,996	147,283,138	349,213,451	-	984,008	-	-
- HVDC	543,705,094	241,538,910	302,166,184	-	-	-	-	-	-	-
TRANSMISSION	516,121,887	-	352,078,611	97,495,085	66,548,191	-	-	-	-	-
- HVDC	109,577,208	109,577,208	-	-	-	-	-	-	-	-
DISTRIBUTION	1,325,750,585	-	-	-	-	1,273,846,923	-	-	51,053,786	849,876
SUBTRANSMISSION	189,793,483	-	-	-	183,112,381	6,681,102	-	-	-	-
TRANSFORMERS										
- SUBSTATION	9,543,386	27,561	3,306,893	903,149	1,362,203	3,943,579	-	-	-	-
- DISTRIBUTION	8,683,300	-	-	-	-	8,683,300	-	-	-	-
METERS	29,057,632	-	-	-	-	29,057,632	-	-	-	-
BUILDINGS	402,990,400	169,810,543	50,498,565	8,274,101	25,154,000	70,993,105	71,765,540	-	6,068,792	425,755
COMMUNICATION	281,804,610	61,143,090	24,614,675	7,909,843	50,973,556	74,402,985	-	62,760,461	-	-
GENERAL EQUIPMENT	220,623,287	92,955,775	27,698,872	4,538,411	13,797,173	38,940,294	39,363,980	-	3,328,782	-
SUBTOTAL	9,879,898,761	5,918,800,072	1,187,205,069	179,979,585	488,230,642	1,855,762,372	111,129,521	63,744,469	60,451,360	14,595,672
MOTOR VEHICLES	-									
Rate Base for Capital Tax	9,879,898,761	5,918,800,072	1,187,205,069	179,979,585	488,230,642	1,855,762,372	111,129,521	63,744,469	60,451,360	14,595,672

SCHEDULE C11
Functionalization of Capital Tax

2013 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2013

Asset Class	Capital Tax	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	27,671,582	27,671,582	-	-	-	-	-	-	-	-
-Thermal	1,142,543	1,142,543	-	-	-	-	-	-	-	-
DIESEL	73,272	-	-	-	-	-	-	-	-	73,272
SUBSTATION	5,450,373	31,025	2,347,997	334,777	810,185	1,920,976	-	5,413	-	-
- HVDC	2,990,849	1,328,673	1,662,176	-	-	-	-	-	-	-
TRANSMISSION	2,839,117	-	1,936,737	536,307	366,073	-	-	-	-	-
- HVDC	602,770	602,770	-	-	-	-	-	-	-	-
DISTRIBUTION	7,292,776	-	-	-	-	7,007,261	-	-	280,840	4,675
SUBTRANSMISSION	1,044,029	-	-	-	1,007,277	36,752	-	-	-	-
TRANSFORMERS										
- SUBSTATION	52,497	152	18,191	4,968	7,493	21,693	-	-	-	-
- DISTRIBUTION	47,766	-	-	-	-	47,766	-	-	-	-
METERS	159,842	-	-	-	-	159,842	-	-	-	-
BUILDINGS	2,216,796	934,105	277,786	45,515	138,369	390,524	394,773	-	33,384	2,342
COMMUNICATION	1,550,169	336,340	135,402	43,511	280,399	409,281	-	345,237	-	-
GENERAL EQUIPMENT	1,213,619	511,337	152,368	24,965	75,896	214,205	216,536	-	18,311	-
SUBTOTAL	54,348,000	32,558,527	6,530,656	990,044	2,685,691	10,208,300	611,309	350,650	332,535	80,289
MOTOR VEHICLES	-									
Capital Tax Allocation	54,348,000	32,558,527	6,530,656	990,044	2,685,691	10,208,300	611,309	350,650	332,535	80,289

SCHEDULE C12
Functionalization of Operating Costs

2013 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2013
Functionalization of Operating Costs

SCC Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancilary Services	Diesel	Street Lighting	Exports
Common Generation Costs	34,566,340	29,934,220								4,632,120
Generating Station Costs	46,943,036	46,943,036								-
Other Generation Related Costs	996,139	996,139	-	-	-	-		-	-	
Dedicated Gen. Facilities	47,939,175	47,939,175						-	-	-
Hydraulic Generating Stations	150,447,016	150,447,016								
Other Hydraulic Generation Related Cost	17,937,388	17,937,388								
Hydraulic Generation Costs	168,384,405	168,384,405								
Thermal Generating Station	33,616,822	33,616,822								-
Non-Dedicated Gen. Facilities	202,001,227	202,001,227								-
Generation Facilities Costs	249,940,402	249,940,402						-	-	-
Purchased Power/Export Costs	168,831,000	-								168,831,000
Generation Facilities & Costs	***453,337,742***	***279,874,622***						-	-	***173,463,120***
Common Trans. Costs/Revenues	27,116,987	494,177	21,360,973	3,648,087						1,613,750
Generation Switching Stations	2,511,681	-	2,511,681							
HVDC & Collector Facilities	40,907,494	22,960,235	17,947,259							
Networked AC Facilities	4,097,814	-	4,097,814							
Generation Access Transmission	47,516,989	22,960,235	24,556,754							
Regional Networked Trans.	1,770,026	-	1,770,026	-	-					
Transmission Common	15,125,857	-	14,453,144	619,358	-	-	53,355	-		
Transmission Facilities/Costs	***91,529,860***	***23,454,412***	***62,140,898***	***4,267,445***	-	-	***53,355***	-		***1,613,750***
Common Subtransmission Costs	6,314,837	-	-	6,314,837						
Subtrans. Facilities & Costs	***31,357,499***	-	-	***22,032,156***	***9,325,342***	-		-	-	-
Dist. Facilities & Costs	***77,160,131***	-	-	-	***70,118,748***	-		-	***7,041,383***	-
Customer Service Costs	***83,266,761***	-	-	-	-	***83,266,761***		-	-	-
Isolated Diesel Facilities	***7,107,920***	-	-	-	-	-		***7,107,920***		
Communication & Control System	***12,209,467***	***6,000,721***	-	***2,379,929***	***1,103,068***	-	***2,725,748***	-	-	-
	762,566,000	**311,939,439**	**63,798,781**	**29,185,206**	**82,370,535**	**83,266,761**	**2,779,103**	**7,107,920**	**7,041,383**	**175,076,870**

SCHEDULE C13
PAGE 1 OF 2

Adjusted Revenue including DSM Reduction at Approved Rates

2013 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ APPROVED RATES
For Year Ended March 31, 2013

Revenue Class	Unadjusted Revenue	To Operating Expense	To Export Revenue	Other Accrual	General Consumer Adjustment	Total adjusted Revenue	Export Adj to Offset Uniform Rates	Total Revenue After Uniform Rates Adjustment
Residential								
Residential	522,599,532			528,984	2,819,043	525,947,559	18,366,089	544,313,647
Seasonal	7,217,605				38,934	7,256,539	1,421,556	8,678,095
Water Heating	1,168,828			1,183	6,305	1,176,316		1,176,316
	530,985,964			530,167	2,864,282	534,380,413	19,787,645	554,168,058
General Service - Small								
Non Demand	126,104,924			127,645	680,244	126,912,814	1,673,980	128,586,794
Seasonal	529,734				2,858	532,591	38,075	570,666
Water Heating	508,722			515	2,744	511,981		511,981
Total Non Demand	127,143,379			128,160	685,846	127,957,386	1,712,055	129,669,441
Demand	123,257,579			124,763	664,885	124,047,227	395,711	124,442,938
	123,257,579		-	124,763	664,885	124,047,227	395,711	124,442,938
SEP								
GSM	816,405			826	4,404	821,635		821,635
GSL	72,456					72,456		72,456
	888,861			826	4,404	894,091	-	894,091
General Service - Medium	173,020,793			175,134	933,321	174,129,248	38,308	174,167,557
	173,020,793			175,134	933,321	174,129,248	38,308	174,167,557

SCHEDULE C13
PAGE 2 OF 2

General Service - Large								
0 - 30 Kv	81,899,184			82,900	441,786	82,423,870		82,423,870
30 - 100 Kv	34,242,560					34,242,560		34,242,560
31 - 100 Kv Curtailable	8,350,273					8,350,273		8,350,273
Over - 100 Kv	108,151,915					108,151,915		108,151,915
Over - 100 Kv Curtailable	71,758,509					71,758,509		71,758,509
	304,402,441			82,900	441,786	304,927,127	-	304,927,127
Area & Roadway Lighting								
Street Lighting	17,499,565					17,499,565	232,819	17,732,385
Sentinel Lighting	2,869,044			2,904	15,476	2,887,425		2,887,425
	20,368,609		-	2,904	15,476	20,386,990	232,819	20,619,809
Diesel								
Residential	574,500					574,500		574,500
Full Cost	5,472,348					5,472,348		5,472,348
	6,046,848			-	-	6,046,848	-	6,046,848
Construction Power	-					-	-	-
Gen. Consumers Before Adj	1,286,114,474		-	1,044,855	5,610,000	1,292,769,329	22,166,538	1,314,935,868
Accrual - Other	1,044,855			(1,044,855)				
Miscellaneous - Non-Energy	561,000		(561,000)		-	-		
Late Pmt Charges & Cust Adj	5,610,000				(5,610,000)	-		
Total General Consumers	1,293,330,329	-	(561,000)	-	-	1,292,769,329	22,166,538	1,314,935,868
Extra-Provincial	341,167,000		684,000			341,851,000		341,851,000
Other (Non Energy net of Subs)	15,706,000	(15,583,000)	(123,000)			-		
Total Revenue	1,650,203,329	(15,583,000)	-	-	-	1,634,620,329	22,166,538	1,656,786,868

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:		
General Consumers Revenue		1,290.4
Additional GCR		45.3
Extra Provincial Revenue		341.2
Other Revenue (non-energy)		15.6
Total Revenue Per Financial Forecast	$	1,692.5
Cost of Service Adjustments		
a. Transfer of Other Revenue (non-energy) to Operating		(15.6)
b. Uniform Rates Adjustment		22.2
c. Revenue Adjustment/Recognition of 1% Rollback/Sept 1, 2012 Increase		(42.3)
Total Revenue Per Cost of Service Study	$	1,656.8

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

RATE BASE CALCULATION AND REGULATED/INTANGIBLE ITEMS
(In Millions of Dollars)

Allocation of net interest expense and reserve contribution is based upon average net plant in-service forecast for fiscal years 2012 and 2013 adjusted for net regulated/intangible items and net major capital additions forecast to come into service during fiscal year 2012/13 which are included on an in-service date basis. This calculation is summarized below:

	2012	2013
Net Investment (Excluding Motor Vehicles)	$ 8,472.7	$ 9,529.3
Add: Total Net Regulated/Intangible Items	351.4	350.0
Less: Major Capital Item Additions 2013		(1,177.6)
	$ 8,824.1	$ 8,701.7
Average Investment (2012 + 2013) ÷ 2		$ 8,762.9
Add: Major Capital Item Additions 2013 on an in-service date basis		588.8
		$ 9,351,7

THIS PAGE LEFT BLANK

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2013

SECTION D: LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2012/13 has been estimated using forecast energy and peak demand from the System Load Forecast and available class load information.

In PCOSS10 Manitoba Hydro introduced the use of averaged results from multiple Load Research studies to minimize year-to-year variation in the factors used to estimate class demands. The average will be based on the past eight Load Research studies, and will be phased in as data becomes available.

Load research data is used to estimate the average top 50 hourly peaks during both the summer and winter. Class data for 2005/06 to 2010/11 is used in the PCOSS to estimate this average seasonal class demand. Load research data used to estimate non-coincident peaks are based on the eight year average of 2003/04 to 2010/11 data.

Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2012/13 the DSM savings are forecast to be 293 GW.h and 58 MW at generation, or 261 and 51 measured at the meter.

Schedule D1 outlines Manitoba Hydro's calculation of forecast demand for the 2012/13 fiscal year. Forecast 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.

Generation costs are allocated based on energies weighted by relative value of SEP energy in each of 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 2,186,638 MWh and 357.1 MW respectively have been taken from the 2011 Electric 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 D4 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 PCOSS13 from the system peak forecasted in the 2011 Electric Load Forecast for the 2013 fiscal year. This difference of 110 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 (1.5%). 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 the Distribution energy loss differential and Schedule D6 shows the results of this assignment based upon sales at the meter for both energy and capacity.

Residual Losses Assigned on a Differential Percentage 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.

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 1,351 customers was selected from Manitoba Hydro's various customer classes. Normally all General Service Large 30 - 100 kV and >100 kV customers are sampled , however in 2010-11 three new customer loads were added to the General Service Large 30 - 100 kV class, and as there was incomplete data for the period under study, an estimated demand load shape was produced. There was no meter data available for one General Service Large >100 kV customer due to an equipment failure so an estimated demand load shape was produced.

Development of Class Loads

1. Residential Class

The 2012/13 forecast kWh sales to the Residential Class and the forecast number of customers are taken from the 2011 Electric Load Forecast. Load Forecasting provides separate information for Flat Rate Water Heating and Seasonal customers.

In Schedule D5, energy sales have been reduced by the forecast savings of 45 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 kWh sales. Coincident peak load factors have been developed from data from the last three load research studies, and are based on the average top 50 hourly peaks during the winter and summer seasons.

The Flat Rate Water Heating Class coincident demand is estimated on the basis of 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 89.6 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 10.8 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 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 2011 data. Also shown are loads for small subgroups: Water Heating and Seasonal.

As with the Residential Class, General Service Small kWh sales and customer counts are taken from the 2011 Electric 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 66.3 GW.h and 16.2 MW before being grossed up to include Distribution and Transmission losses.

For the General Service Small classes the coincident peak load factors were determined using load research information, with the same load factors 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 162.3% is the same as used in previous studies.

The estimated coincident peaks at the meter have been adjusted by 13.9 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 have been applied to derive class non-coincident peaks.

3. General Service Medium

General Service Medium includes 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 there are 282 pulse metered customers included in the Load Research sample.

Customer and kWh sales data are derived from the load forecast and apportioned among service voltages on the basis of recent past experience. DSM savings of 41.8 GW.h and 8.7 MW have been assigned to this class.

General Service Medium estimated coincident peaks at the meter have been adjusted by 6.7 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.

4. General Service Large

For customers in this class load information has been historically available. Seventy-six percent of the customers in the 0 - 30 kV subclass, 92% of the customers in the 30 - 100 kV subclass and 94% of the customers in the over 100 kV subclass are pulse metered.

The estimated coincident peaks at the meter have been adjusted by 0.0 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 107.8 GW.h and 15.4 MW.

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.

5. Surplus Energy Program

Surplus Energy Program ("SEP") energy sales are taken from the 2011 Electric Load Forecast. Customers and forecast energy have been separated into service voltage levels and into utility or customer owned transformation.

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 2011 Electric Load Forecast. 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 2012/13 is based on the inventory wattage multiplied by 4,252 hours of use per year, a figure based on Load Research results. The customer count is based on June 2011 actual billing data plus forecast additions to the system of 760 lights to year end 2013. 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.

7. Export Class

Forecast Export energy in PCOSS13 includes 7,340 GWh in sales, which equals 7,998 GWh at Generation after adding back transmission losses of 658 GWh

Export energy sales used to determine 'Seasonal 2CP Demand' in Schedule D1 has been reduced by the forecast 153 GWh of US On Peak purchases in PCOSS13 (with no methodology changes). These purchases are assumed to serve On Peak US sales in a median flow year, and would not physically use Manitoba Hydro's Transmission system.

Only dependable export energy sales of 3,588 GWh, 3,910 GWh after allocation of losses, are used to determine 'Seasonal 2CP Demand' in Schedule D7 as only dependable sales attract embedded transmission costs in this methodology.

Export energy sales in Schedule D2 '12 Period Marginal Cost Weighted Energy' has been reduced for 3,497 GWh in Imports, including wind purchases, deemed to serve export markets in PCOSS13 (with no methodology changes). Export energy sales in Schedule D8 represent the dependable export sales of 3,909 GWh, and are not adjusted for import purchases in PCOSS13 (with methodology changes).

SCHEDULE D1

Seasonal Coincident Peaks (2 CP) at Generation Peak – No Methodology Changes

2013 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	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	8,385,584,029	63.3%	5,308,074,691	75.5%	1,618,454	36.7%	3,077,509,339	82.9%	840,651	1,229,552
Seasonal	95,113,667	43.3%	41,225,370	162.5%	5,840	56.7%	53,888,297	162.5%	7,510	6,675
Water Heating	16,966,912	49.5%	8,392,174	126.0%	1,533	50.5%	8,574,738	126.0%	1,541	1,537
Total Residential	8,497,664,609		5,357,692,235		1,625,827		3,139,972,374		849,702	1,237,764
GS Small										
Non-Demand	1,862,693,416	58.4%	1,087,812,955	77.3%	323,955	41.6%	774,880,461	74.0%	237,123	280,539
Demand	2,275,659,466	56.3%	1,281,196,280	81.2%	363,220	43.7%	994,463,187	81.7%	275,637	319,429
Subtotal	4,138,352,883		2,369,009,235		687,175		1,769,343,648		512,760	599,968
Seasonal	5,531,544	20.0%	1,106,309	162.5%	157	80.0%	4,425,235	162.5%	617	387
Water Heating	5,795,842	49.7%	2,882,619	106.0%	626	50.3%	2,913,222	106.0%	622	624
Total GSS	4,149,680,268		2,372,998,163		687,958		1,776,682,105		513,999	600,979
General Service - Medium	3,568,243,578	53.1%	1,894,737,340	83.0%	525,510	46.9%	1,673,506,238	80.7%	469,596	497,553
General Service - Large										
0 - 30 Kv	1,964,268,440	50.6%	993,919,831	85.1%	268,864	49.4%	970,348,609	82.8%	265,380	267,122
30 - 100 Kv	924,835,587	52.1%	481,839,341	96.1%	115,422	47.9%	442,996,246	99.4%	100,922	108,172
30 - 100 Kv - Curtailed Cust	247,281,363	49.1%	121,415,149	99.4%	28,119	50.9%	125,866,214	100.5%	28,361	28,240
Over 100 Kv	3,142,334,602	52.5%	1,649,725,666	98.1%	387,127	47.5%	1,492,608,936	106.7%	316,776	351,951
Over 100 Kv - Curtailed Cust	2,181,777,774	50.0%	1,090,888,887	99.5%	252,387	50.0%	1,090,888,887	100.4%	246,047	249,217
Total G.S.- Large	8,460,497,766		4,337,788,874		1,051,918		4,122,708,892		957,485	1,004,702
Street Lighting	117,018,968	57.5%	67,294,199	86.7%	17,878	42.5%	49,724,769	0.0%	-	8,939
Total - General Consumers	24,793,105,189		14,030,510,810		3,909,091		10,762,594,379		2,790,783	3,349,937
Extra Provincial	7,845,000,000	37.1%	2,910,495,000	94.3%	710,502	62.9%	4,934,505,000	84.2%	1,327,096	1,018,799
Integrated System	32,638,105,189		16,941,005,810		4,619,594		15,697,099,379		4,117,879	4,368,736

SCHEDULE D2

Prospective Peak Load Responsibility Report Energy (kWh) – No Methodology Changes Weighted by Marginal Cost

2013 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report

Energy (MW.h) Weighted by Marginal Cost (Hydraulic for Domestic and Export Classes)

			Spring			Summer			Fall			Winter				
	2012/13 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	8,348,041,341	Residential	263,855,531	510,897,966	325,791,845	516,658,548	948,683,360	487,301,545	349,456,142	636,566,673	401,626,823	958,067,078	1,752,571,756	1,196,564,072	8,348,041,341	20,632,462
Res FRWH	16,890,950	Residential FRWH	674,934	1,306,860	833,365	1,489,750	2,735,465	1,405,101	708,950	1,291,418	814,790	1,380,584	2,525,473	1,724,260	16,890,950	40,822
Res Seasonal	94,687,838	Residential Seasonal	4,035,427	7,813,713	4,982,686	9,463,137	17,376,120	8,925,433	3,709,700	6,757,562	4,263,525	6,708,950	12,272,539	8,379,046	94,687,838	227,223
GS Small Non Demand	1,854,354,043	GS Small Non-Demand	67,633,080	122,889,849	72,556,502	157,089,289	231,414,453	131,659,352	80,561,050	139,127,122	84,646,041	196,117,767	345,836,403	224,823,135	1,854,354,043	4,591,141
GSS FRWH	5,769,893	GS Small Non-Demand FRWH	247,223	449,206	265,220	580,836	855,653	486,809	254,560	439,620	267,468	491,920	867,457	563,921	5,769,893	14,100
GSS Seasonal	5,506,779	GS Small Non-Demand Season	306,734	557,338	329,063	886,959	1,306,614	743,376	170,066	293,701	178,690	187,795	331,160	215,282	5,506,779	13,058
GS Small Demand	2,265,471,223	GS Small Demand	82,641,329	148,561,883	91,214,622	179,751,433	291,967,209	173,403,466	100,036,584	173,897,634	109,054,257	231,617,170	410,440,511	272,885,126	2,265,471,223	5,558,003
GS Medium	3,552,268,369	GS Medium	138,018,608	244,506,163	149,466,868	311,344,043	501,908,634	302,448,253	154,580,076	266,415,713	165,339,011	339,975,549	591,942,880	386,322,571	3,552,268,369	8,679,243
GS Large <30KV	1,955,474,309	GS Large 750-30kV	80,723,238	137,268,652	89,540,504	179,112,549	282,506,592	185,315,435	85,789,404	142,475,609	94,873,361	178,167,167	297,982,793	201,719,006	1,955,474,309	4,738,491
GS Large 30-100kV	920,695,051	GS Large 30-100kV	31,781,230	63,017,681	48,579,059	67,009,728	126,366,104	98,186,243	35,641,191	68,570,285	53,512,849	74,235,811	142,791,805	111,003,065	920,695,051	2,158,528
GS Large 30-100kV Curtail	246,174,272	GS Large 30-100kV Curtailable	9,104,842	18,299,883	13,709,546	18,734,380	36,193,237	27,594,483	9,459,946	18,457,379	14,017,012	18,220,074	35,479,435	26,904,056	246,174,272	574,130
GS Large > 100kV	3,128,266,209	GS Large > 100kV	117,976,803	230,848,984	178,681,452	219,646,254	407,757,412	320,993,454	122,008,872	234,220,479	182,353,939	254,634,467	482,830,439	376,313,654	3,128,266,209	7,336,687
GS Large > 100kV Curtail	2,172,009,844	GS >100kV Curtailable	79,322,892	157,406,257	120,537,235	161,472,997	313,740,777	242,405,095	80,525,510	157,486,546	120,569,156	166,416,123	323,580,657	248,546,597	2,172,009,844	5,070,124
Streetlights	116,495,068	Street Lights	-	4,426,813	10,892,289	465,980	8,271,150	21,842,825	3,378,357	6,640,219	13,280,438	7,921,665	13,338,685	26,036,648	116,495,068	231,163
Total	24,682,105,189	Totals	876,321,871	1,648,251,250	1,107,380,256	1,823,705,884	3,171,082,779	2,002,710,870	1,026,280,409	1,852,639,960	1,244,797,361	2,434,142,119	4,412,791,991	3,082,000,439	24,682,105,189	59,865,176
Exports	4,501,000,000	Exports	235,955,260	400,222,018	185,690,767	524,410,953	893,599,643	524,995,482	175,669,122	333,385,894	215,668,053	272,260,302	487,981,737	251,160,770	4,501,000,000	10,770,278
		Weighting Factor	2.847	2.330	1.436	3.541	2.354	1.000	2.931	2.363	1.482	3.717	2.602	2.028		

Energy (MW.h) Weighted by Marginal Cost (Thermal for Domestic Classes)

			Spring			Summer			Fall			Winter				
Thermal Generation	2012/13 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	37,542,689	Residential	1,186,607	2,297,603	1,465,146	2,323,509	4,266,405	2,191,485	1,571,569	2,862,758	1,806,190	4,308,605	7,881,640	5,381,170	37,542,689	92,788
Res FRWH	75,962	Residential FRWH	3,035	5,877	3,748	6,700	12,302	6,319	3,188	5,808	3,664	6,209	11,358	7,754	75,962	184
Res Seasonal	425,829	Residential Seasonal	18,148	35,140	22,408	42,557	78,144	40,139	16,683	30,390	19,174	30,171	55,192	37,682	425,829	1,022
GS Small Non Demand	8,339,374	GS Small Non-Demand	304,158	552,658	326,300	706,460	1,040,714	592,096	362,298	625,680	380,669	881,978	1,555,290	1,011,071	8,339,374	20,647
GSS FRWH	25,948	GS Small Non-Demand FRWH	1,112	2,020	1,193	2,612	3,848	2,189	1,145	1,977	1,203	2,212	3,901	2,536	25,948	63
GSS Seasonal	24,765	GS Small Non-Demand Season	1,379	2,506	1,480	3,989	5,876	3,343	765	1,321	804	845	1,489	968	24,765	59
GS Small Demand	10,188,244	GS Small Demand	371,653	668,110	410,209	808,375	1,313,031	779,828	449,883	782,050	490,437	1,041,625	1,845,827	1,227,215	10,188,244	24,995
GS Medium	15,975,209	GS Medium	620,695	1,099,590	672,180	1,400,172	2,257,176	1,360,166	695,175	1,198,121	743,560	1,528,933	2,662,077	1,737,364	15,975,209	39,032
GS Large <30KV	8,794,130	GS Large 750-30kV	363,027	617,323	402,680	805,502	1,270,484	833,398	385,811	640,739	426,663	801,251	1,340,084	907,168	8,794,130	21,310
GS Large 30-100kV	4,140,536	GS Large 30-100kV	142,926	283,402	218,469	301,355	568,292	441,562	160,285	308,373	240,657	333,852	642,161	499,201	4,140,536	9,707
GS Large 30-100kV Curtail	1,107,091	GS Large 30-100kV Curtailable	40,946	82,298	61,654	84,252	162,768	124,098	42,543	83,006	63,037	81,939	159,558	120,993	1,107,091	2,582
GS Large > 100kV	14,068,393	GS Large > 100kV	530,564	1,038,171	803,564	987,790	1,833,761	1,443,567	548,697	1,053,333	820,079	1,145,138	2,171,378	1,692,352	14,068,393	32,994
GS Large > 100kV Curtail	9,767,931	GS >100kV Curtailable	356,730	707,885	542,078	726,174	1,410,950	1,090,141	362,138	708,246	542,222	748,404	1,455,202	1,117,760	9,767,931	22,801
Streetlights	523,900	Street Lights	-	19,908	48,985	2,096	37,197	98,231	15,193	29,862	59,725	35,625	59,987	117,092	523,900	1,040
Thermal Generation	111,000,000	Totals	3,940,982	7,412,491	4,980,094	8,201,543	14,260,947	9,006,562	4,615,373	8,331,665	5,598,084	10,946,788	19,845,143	13,860,327	111,000,000	269,225
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	2.847	2.330	1.436	3.541	2.354	1.000	2.931	2.363	1.482	3.717	2.602	2.028		

Definition of Periods

Spring (April 1 to May 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Summer (June 1 to Sept 30)
Peak = 12:00 noon to 8:00 pm weekdays
Shoulder = 7:00 am to 12:00 noon weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Fall (Oct 1 to Nov 30)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Winter (December 1 to March 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
March 31, 2013

CALCULATION OF LOSSES

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	24,934,175,669
Common Bus Losses (After DSM)	2,186,638,213
Deliveries From Common Bus	22,747,537,456
Sales at Meter	21,805,819,508
Distribution Losses	941,717,948

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	4,430.70
Common Bus Losses (After DSM)	357.11
Deliveries From Common Bus	4,073.59
Calculated Distribution Losses	228.27
Calculated Demand at Meter (CP Load Factors)	3,735.12
Less: Adj made for curtailable load added back	-
Adjustment To Reconcile	110.20

SCHEDULE D4
Determination of Coincident Peak Distribution Losses

MANITOBA HYDRO
2013 PROSPECTIVE COST OF SERVICE STUDY
March 31, 2013
DETERMINATION OF COINCIDENT PEAK DISTRIBUTION LOSSES

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	Losses	Energy @ Common Bus
RESIDENTIAL	7,266,317,553	486,132,199	7,752,449,752
G.S.S. SINGLE PHASE	1,352,993,509	90,518,162	1,443,511,671
G.S.S. THREE PHASE	2,230,928,348	111,328,100	2,342,256,449
* G.S.M.	3,124,095,023	155,899,029	3,279,994,052
* G.S.L. O - 30	1,723,692,298	70,502,705	1,794,195,003
G.S.L. 30 - 100	1,053,523,623	15,802,854	1,069,326,477
LIGHTING	100,062,431	6,694,391	106,756,822
MAN. HYDRO CONSTRUCTION	97,000,000	4,840,508	101,840,508
	16,948,612,785	941,717,948	17,890,330,733

* (includes SEP sales)

2) COINCIDENT PEAK AT COMMON BUS

C.P. AT GENERATION	4,430.70
LESS SALES AT CB LEVEL :	
- EXPORTS	0.00
- * G.S.L. >100	(588.10)
C.B. LOSSES	(357.11)
EXPORT LOSSES	0.00
COINCIDENT PEAK AT COMMON BUS	3,485.49

3) LOAD FACTOR AT COMMON BUS 58.6%
(Hours per Year = 8,760)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = $(0.08 \times 58.59\%) + (0.92 \times (58.59\%)^2)$
= 0.362730

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

a) 941,718 x 0.1800 = 169,509 MW.H

b) $\frac{941{,}718 \times 0.1800}{8{,}760}$ = 19.4 MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{941{,}718. - 169{,}509}{8{,}760 \times (3{,}485.49)^2 \times 0.36273}$$
= 0.000020

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

= $19.35 + 0.00002 \times (3{,}485.49)^2$
= 262.37

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 228.265 MW

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

AVERAGE (KW.h)	941,718	/ 16,948,613	= 5.56%
PEAK (MW)	228.27	/ 3,257.229	= 7.01%

SCHEDULE D5
PAGE 1 OF 2
Prospective Peak Load Report - Using Top 50 Peak Hours

2013 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	Forecast DSM KW.h Savings	Total KW.h Sales After DSM E20	Distribution Losses	Common Bus Losses	KW.h Generated Adjusted E10
Residential							
Residential	455,614	7,215,717,688	(45,239,771)	7,170,477,917	479,720,322	735,385,790	8,385,584,029
Seasonal	21,286	81,331,300	-	81,331,300	5,441,238	8,341,129	95,113,667
Water Heating	4,096	14,508,336	-	14,508,336	970,639	1,487,938	16,966,912
Total Residential	480,996	7,311,557,324	(45,239,771)	7,266,317,553	486,132,199	745,214,857	8,497,664,609
GS Small - Single Phase							
Non-Demand	41,024	985,764,160	(17,193,483)	968,570,677	64,799,452	99,334,120	1,132,704,249
Demand	4,367	381,926,272	(7,189,440)	374,736,832	25,070,696	38,432,047	438,239,574
Subtotal	45,391	1,367,690,432	(24,382,923)	1,343,307,509	89,870,148	137,766,166	1,570,943,823
Seasonal	854	4,730,000	-	4,730,000	316,447	485,097	5,531,544
Water Heating	398	4,956,000	-	4,956,000	331,567	508,275	5,795,842
Total Single Phase	46,643	1,377,376,432	(24,382,923)	1,352,993,509	90,518,162	138,759,538	1,582,271,208
GS Small - Three Phase							
Non-Demand	11,438	645,577,931	(11,260,029)	634,317,902	31,653,821	64,017,445	729,989,168
Demand	7,930	1,627,241,905	(30,631,459)	1,596,610,446	79,674,279	161,135,167	1,837,419,892
Total Three Phase	19,368	2,272,819,836	(41,891,488)	2,230,928,348	111,328,100	225,152,611	2,567,409,060
Total G.S.Small							
Non-Demand	52,462	1,631,342,091	(28,453,512)	1,602,888,579	96,453,273	163,351,564	1,862,693,416
Demand	12,297	2,009,168,177	(37,820,899)	1,971,347,278	104,744,975	199,567,213	2,275,659,466
Sub-Total G.S. Small	64,759	3,640,510,268	(66,274,411)	3,574,235,857	201,198,248	362,918,778	4,138,352,883
Seasonal	854	4,730,000	-	4,730,000	316,447	485,097	5,531,544
Water Heating	398	4,956,000	-	4,956,000	331,567	508,275	5,795,842
Total GS Small	66,011	3,650,196,268	(66,274,411)	3,583,921,857	201,846,262	363,912,149	4,149,680,268
General Service - Medium	1,938	3,142,384,907	(41,789,884)	3,100,595,023	154,726,329	312,922,226	3,568,243,578
General Service - Large							
0 - 30 Kv	289	1,744,261,000	(22,668,702)	1,721,592,298	70,416,810	172,259,331	1,964,268,440
30 - 100 kV	39	841,502,992	(10,241,113)	831,261,879	12,468,928	81,104,780	924,835,587
30 - 100 kV - Curtailment Cust's	1	225,000,000	(2,738,256)	222,261,744	3,333,926	21,685,693	247,281,363
Over 100 Kv	14	2,909,332,000	(42,568,927)	2,866,763,073	-	275,571,529	3,142,334,602
Over 100 Kv - Curtailment Cust's	2	2,020,000,000	(29,556,350)	1,990,443,650	-	191,334,124	2,181,777,774
Total G.S.- Large	345	7,740,095,992	(107,773,348)	7,632,322,644	86,219,665	741,955,458	8,460,497,766
SEP							
GSM	21	23,500,000		23,500,000	1,172,700	2,371,697	27,044,397
GSL 0 - 30 Kv	5	2,100,000		2,100,000	85,894	210,122	2,396,017
Total SEP	26	25,600,000	-	25,600,000	1,258,595	2,581,819	29,440,414
Street Lighting	127,637	88,437,208	-	88,437,208	5,916,639	9,069,893	103,423,739
Sentinel Lighting	25,807	11,625,223	-	11,625,223	777,752	1,192,253	13,595,228
Total - Lighting	153,444	100,062,431	-	100,062,431	6,694,391	10,262,146	117,018,968
Total - General Consumers	702,760	21,969,896,922	(261,077,414)	21,708,819,508	936,877,440	2,176,848,655	24,822,545,603
Extra Provincial		-	-	-		-	-
Man Hydro - Construction		97,000,000		97,000,000	4,840,508	9,789,558	111,630,066
Integrated System	702,760	22,066,896,922	(261,077,414)	21,805,819,508	941,717,948	2,186,638,213	24,934,175,669

SCHEDULE D5
PAGE 2 OF 2

2013 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	Forecast 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	CP @ Gen. MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
Residential													
Residential	50.7%	1,626.0	(10.8)	1,615.2	81.3%	89.6	1,704.8	138.1	161.6	2,004.4	90.8%	1,878.1	2,208.3
Seasonal	157.8%	5.9		5.9		-	5.9	0.5	0.6	6.9	8.0%	73.6	86.5
Water Heating	67.4%	2.5		2.5		-	2.5	0.2	0.2	2.9	80.0%	3.1	3.6
Total Residential	51.1%	1,634.3	(10.8)	1,623.5	81.3%	89.6	1,713.1	138.8	162.3	2,014.3	87.6%	1,954.8	2,298.4
GS Small - Single Phase													
Non-Demand	62.1%	181.2	(4.5)	176.7	5.5%	6.0	182.7	14.8	17.3	214.8	86.4%	211.5	248.7
Demand	66.0%	66.1	(1.7)	64.4	0.7%	0.7	65.1	5.3	6.2	76.6	88.9%	73.3	86.2
Subtotal	63.2%	247.2	(6.2)	241.1	6.2%	6.8	247.8	20.1	23.5	291.4	87.0%	284.8	334.9
Seasonal	162.5%	0.3		0.3			0.3	0.0	0.0	0.4	8.0%	4.2	4.9
Water Heating	71.8%	0.8		0.8			0.8	0.1	0.1	0.9	75.0%	1.1	1.2
Total Single Phase	63.3%	248.3	(6.2)	242.2	6.2%	6.8	249.0	20.2	23.6	292.7	85.8%	290.0	341.0
GS Small - Three Phase													
Non-Demand	62.1%	118.6	(2.9)	115.7	3.6%	4.0	119.7	7.1	11.1	137.9	86.4%	138.5	159.7
Demand	66.0%	281.5	(7.2)	274.3	2.9%	3.2	277.5	16.5	25.8	319.8	88.9%	312.3	359.9
Total Three Phase	64.8%	400.1	(10.1)	390.0	6.5%	7.1	397.2	23.7	36.9	457.7	88.1%	450.9	519.6
Total G.S.Small													
Non-Demand	61.0%	299.8	(7.4)	292.4	9.1%	10.0	302.4	21.9	28.4	352.7	86.4%	350.1	408.4
Demand	64.7%	347.6	(8.8)	338.7	3.6%	3.9	342.7	21.8	32.0	396.4	88.9%	385.6	446.1
Sub-Total G.S. Small	64.2%	647.3	(16.2)	631.1	12.6%	13.9	645.0	43.7	60.4	749.1	87.7%	735.7	854.5
Seasonal	162.6%	0.3	-	0.3	0.0%	-	0.3	0.0	0.0	0.4	8.0%	4.2	4.9
Water Heating	71.8%	0.8	-	0.8	0.0%	-	0.8	0.1	0.1	0.9	75.0%	1.1	1.2
Total GS Small	64.3%	648.5	(16.2)	632.2	12.6%	13.9	646.1	43.8	60.5	750.5	87.2%	740.9	860.6
General Service - Medium	72.5%	495.1	(8.7)	486.4	6.1%	6.7	493.1	29.4	45.8	568.3	91.6%	538.6	620.7
General Service - Large													
0 - 30 Kv	79.7%	249.9	(4.4)	245.4	0.0%	0.0	245.4	11.8	22.6	279.8	90.0%	272.9	311.1
30 - 100 kV	90.8%	105.7	(1.7)	104.1		-	104.1	2.0	9.3	115.3	75.2%	138.4	153.4
30 - 100 kV - Curtailment Cust's	101.8%	25.2	(0.4)	24.8		-	24.8	0.5	2.2 †	27.5	91.0%	27.3	30.3
Over 100 Kv	91.1%	364.6	(5.5)	359.2		-	359.2	-	31.5	390.7	87.9%	408.6	444.5
Over 100 Kv - Curtailment Cust's	99.2%	232.4	(3.5)	228.9		-	228.9	-	20.1 †	249.0	81.7%	280.3	304.9
Total G.S.- Large	90.4%	977.9	(15.4)	962.5	0.0%	0.0	962.5	14.3	85.6	1,062.3	85.4%	1,127.5	1,244.1
SEP													
GSM	49.5%	5.4		5.4		-	5.4	0.3	0.5	6.3	74.7%	7.3	8.4
GSL 0 - 30 Kv	105.2%	0.2		0.2		-	0.2	0.0	0.0	0.3	15.0%	1.5	1.7
Total SEP	51.7%	5.7	-	5.7		-	5.7	0.3	0.5	6.5	64.3%	8.8	10.1
Street Lighting	119.7%	8.4	-	8.4		-	8.4	0.7	0.8	9.9	38.2%	22.1	26.0
Sentinel Lighting	119.7%	1.1	-	1.1		-	1.1	0.1	0.1	1.3	38.2%	2.9	3.4
Total - Lighting	119.7%	9.5	-	9.5	0.0%	-	9.5	0.8	0.9	11.2	38.2%	25.0	29.4
Total - General Consumers	66.5%	3,771.0	(51.1)	3,719.8	100.0%	110.2	3,830.0	227.4	355.7	4,413.1	87.1%	4,395.6	5,063.3
Extra Provincial	0.0%	0.0		0.0		-	-		-	0.0			
Man Hydro - Construction	72.5%	15.3		15.3		-	15.3	0.9	1.4	17.6			
Integrated System	66.5%	3,786.3	(51.1)	3,735.1	100.0%	110.2	3,845.3	228.3	357.1	4,430.7			

SCHEDULE D6
Distribution Energy and Capacity Losses

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2013

Distribution Energy Losses Expressed as a %'age of Kwh @ meter

	Class Avg
Export Sales	n/a
GS Large	
< 30	4.1%
30-100	1.5%
> 100	n/a
GS Medium	5.0%
GS Small	
3 Phase	5.0%
1 Phase	6.7%
Residential	6.7%
Area & Roadway Lighting	6.7%

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2013

Distribution Capacity Losses Expressed as a %'age of MW @ meter

	Class Avg
Export Sales	n/a
GS Large	
< 30	4.8%
30-100	1.9%
> 100	n/a
GS Medium	6.0%
GS Small	
3 Phase	6.0%
1 Phase	8.1%
Residential	8.1%
Area & Roadway Lighting	8.1%

SCHEDULE D7

Seasonal Coincident Peaks (2 CP) at Generation Peak – With Methodology Changes

2013 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	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	8,385,584,029	63.3%	5,308,074,691	75.5%	1,618,454	36.7%	3,077,509,339	82.9%	840,651	1,229,552
Seasonal	95,113,667	43.3%	41,225,370	162.5%	5,840	56.7%	53,888,297	162.5%	7,510	6,675
Water Heating	16,966,912	49.5%	8,392,174	126.0%	1,533	50.5%	8,574,738	126.0%	1,541	1,537
Total Residential	8,497,664,609		5,357,692,235		1,625,827		3,139,972,374		849,702	1,237,764
GS Small										
Non-Demand	1,862,693,416	58.4%	1,087,812,955	77.3%	323,955	41.6%	774,880,461	74.0%	237,123	280,539
Demand	2,275,659,466	56.3%	1,281,196,280	81.2%	363,220	43.7%	994,463,187	81.7%	275,637	319,429
Subtotal	4,138,352,883		2,369,009,235		687,175		1,769,343,648		512,760	599,968
Seasonal	5,531,544	20.0%	1,106,309	162.5%	157	80.0%	4,425,235	162.5%	617	387
Water Heating	5,795,842	49.7%	2,882,619	106.0%	626	50.3%	2,913,222	106.0%	622	624
Total GSS	4,149,680,268		2,372,998,163		687,958		1,776,682,105		513,999	600,979
General Service - Medium	3,568,243,578	53.1%	1,894,737,340	83.0%	525,510	46.9%	1,673,506,238	80.7%	469,596	497,553
General Service - Large										
0 - 30 Kv	1,964,268,440	50.6%	993,919,831	85.1%	268,864	49.4%	970,348,609	82.8%	265,380	267,122
30 - 100 Kv	924,835,587	52.1%	481,839,341	96.1%	115,422	47.9%	442,996,246	99.4%	100,922	108,172
30 - 100 Kv - Curtailed Cust	247,281,363	49.1%	121,415,149	99.4%	28,119	50.9%	125,866,214	100.5%	28,361	28,240
Over 100 Kv	3,142,334,602	52.5%	1,649,725,666	98.1%	387,127	47.5%	1,492,608,936	106.7%	316,776	351,951
Over 100 Kv - Curtailed Cust	2,181,777,774	50.0%	1,090,888,887	99.5%	252,387	50.0%	1,090,888,887	100.4%	246,047	249,217
Total G.S.- Large	8,460,497,766		4,337,788,874		1,051,918		4,122,708,892		957,485	1,004,702
Street Lighting	117,018,968	57.5%	67,294,199	86.7%	17,878	42.5%	49,724,769	0.0%	-	8,939
Total - General Consumers	24,793,105,189		14,030,510,810		3,909,091		10,762,594,379		2,790,783	3,349,937
Extra Provincial	3,909,600,000	37.1%	1,450,461,600	94.3%	354,083	62.9%	2,459,138,400	84.2%	661,366	507,724
Integrated System	28,702,705,189		15,480,972,410		4,263,174		13,221,732,779		3,452,149	3,857,661

SCHEDULE D8

Prospective Peak Load Responsibility Report Energy (kWh)-With Methodology Changes

Weighted by Marginal Cost

2013 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report

Energy (MW.h) Weighted by Marginal Cost (Hydraulic for Domestic and Export Classes)

			Spring			Summer			Fall			Winter				
	2012/13 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	8,366,643,574	Residential	264,443,490	512,036,418	326,517,818	517,809,837	950,797,345	488,387,416	350,234,847	637,985,157	402,521,782	960,201,973	1,756,477,073	1,199,230,418	8,366,643,574	20,678,438
Res FRWH	16,928,589	Residential FRWH	676,438	1,309,772	835,222	1,493,070	2,741,561	1,408,232	710,530	1,294,296	816,606	1,383,660	2,531,100	1,728,103	16,928,589	40,913
Res Seasonal	94,898,835	Residential Seasonal	4,044,419	7,831,125	4,993,789	9,484,224	17,414,840	8,945,322	3,717,967	6,772,620	4,273,026	6,723,899	12,299,886	8,397,717	94,898,835	227,729
GS Small Non Demand	1,858,486,165	GS Small Non-Demand	67,783,789	123,163,689	72,718,182	157,439,337	231,930,122	131,952,733	80,740,567	139,437,144	84,834,661	196,554,783	346,607,042	225,324,116	1,858,486,165	4,601,372
GSS FRWH	5,782,751	GS Small Non-Demand FRWH	247,774	450,207	265,811	582,130	857,559	487,894	255,128	440,600	268,064	493,016	869,390	565,178	5,782,751	14,132
GSS Seasonal	5,519,050	GS Small Non-Demand Season	307,418	558,580	329,796	888,935	1,309,526	745,032	170,445	294,355	179,088	188,213	331,898	215,762	5,519,050	13,088
GS Small Demand	2,270,519,451	GS Small Demand	82,825,482	148,892,929	91,417,879	180,151,979	292,617,810	173,789,867	100,259,499	174,285,136	109,297,266	232,133,291	411,355,110	273,493,205	2,270,519,451	5,570,388
GS Medium	3,560,184,013	GS Medium	138,326,160	245,051,005	149,799,930	312,037,822	503,027,054	303,122,209	154,924,532	267,009,377	165,707,442	340,733,128	593,261,927	387,183,427	3,560,184,013	8,698,583
GS Large <30KV	1,959,831,761	GS Large 750-30kV	80,903,117	137,574,533	89,740,030	179,511,672	283,136,111	185,728,380	85,980,572	142,793,093	95,084,771	178,564,183	298,646,798	202,168,503	1,959,831,761	4,749,050
GS Large 30-100kV	922,746,668	GS Large 30-100kV	31,852,049	63,158,105	48,687,309	67,159,048	126,647,690	98,405,035	35,720,612	68,723,082	53,632,094	74,401,234	143,109,993	111,250,417	922,746,668	2,163,338
GS Large 30-100kV Curtail	246,722,831	GS Large 30-100kV Curtailable	9,125,130	18,340,661	13,740,095	18,776,126	36,273,888	27,655,973	9,481,026	18,498,508	14,048,246	18,260,674	35,558,495	26,964,007	246,722,831	575,409
GS Large > 100kV	3,135,237,034	GS Large > 100kV	118,239,695	231,363,393	179,079,615	220,135,699	408,666,032	321,708,735	122,280,748	234,742,401	182,760,285	255,201,878	483,906,347	377,152,207	3,135,237,034	7,353,036
GS Large > 100kV Curtail	2,176,849,809	GS >100kV Curtailable	79,499,650	157,757,011	120,805,832	161,832,813	314,439,897	242,945,255	80,704,948	157,837,479	120,837,825	166,786,954	324,301,703	249,100,442	2,176,849,809	5,081,422
Streetlights	116,754,658	Street Lights	-	4,436,677	10,916,561	467,019	8,289,581	21,891,498	3,385,885	6,655,015	13,310,031	7,939,317	13,368,408	26,094,666	116,754,658	231,678
Total	24,737,105,189	Totals	878,274,610	1,651,924,106	1,109,847,870	1,827,769,712	3,178,149,014	2,007,173,581	1,028,567,306	1,856,768,263	1,247,571,186	2,439,566,203	4,422,625,170	3,088,868,168	24,737,105,189	59,998,576
Exports	3,909,600,000	Exports	204,952,385	347,635,637	161,292,296	455,507,012	776,186,883	456,014,738	152,587,425	289,581,314	187,330,775	236,487,198	423,864,341	218,159,997	3,909,600,000	9,355,139
		Weighting Factor	2.847	2.330	1.436	3.541	2.354	1.000	2.931	2.363	1.482	3.717	2.602	2.028		

Energy (MW.h) Weighted by Marginal Cost (Thermal for Domestic Classes)

			Spring			Summer			Fall			Winter				
Thermal Generation	2012/13 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	18,940,456	Residential	598,649	1,159,151	739,173	1,172,221	2,152,420	1,105,614	792,864	1,444,274	911,231	2,173,711	3,976,323	2,714,825	18,940,456	46,812
Res FRWH	38,323	Residential FRWH	1,531	2,965	1,891	3,380	6,206	3,188	1,609	2,930	1,849	3,132	5,730	3,912	38,323	93
Res Seasonal	214,833	Residential Seasonal	9,156	17,728	11,305	21,470	39,424	20,250	8,417	15,332	9,673	15,222	27,845	19,011	214,833	516
GS Small Non Demand	4,207,252	GS Small Non-Demand	153,449	278,819	164,620	356,412	525,045	298,715	182,781	315,659	192,049	444,962	784,651	510,090	4,207,252	10,417
GSS FRWH	13,091	GS Small Non-Demand FRWH	561	1,019	602	1,318	1,941	1,104	578	997	607	1,116	1,968	1,279	13,091	32
GSS Seasonal	12,494	GS Small Non-Demand Season	696	1,265	747	2,012	2,965	1,687	386	666	405	426	751	488	12,494	30
GS Small Demand	5,140,015	GS Small Demand	187,501	337,065	206,952	407,829	662,430	393,426	226,968	394,548	247,428	525,505	931,228	619,135	5,140,015	12,610
GS Medium	8,059,565	GS Medium	313,144	554,748	339,118	706,393	1,138,756	686,210	350,719	604,457	375,129	771,354	1,343,030	876,508	8,059,565	19,692
GS Large <30KV	4,436,678	GS Large 750-30kV	183,149	311,442	203,154	406,380	640,965	420,453	194,643	323,256	215,253	404,235	676,078	457,670	4,436,678	10,751
GS Large 30-100kV	2,088,919	GS Large 30-100kV	72,107	142,978	110,219	152,035	286,706	222,770	80,865	155,576	121,413	168,430	323,973	251,849	2,088,919	4,897
GS Large 30-100kV Curtail	558,533	GS Large 30-100kV Curtailable	20,658	41,520	31,105	42,506	82,117	62,608	21,463	41,877	31,803	41,339	80,498	61,041	558,533	1,303
GS Large > 100kV	7,097,568	GS Large > 100kV	267,672	523,762	405,401	498,344	925,140	728,286	276,820	531,411	413,734	577,727	1,095,470	853,799	7,097,568	16,646
GS Large > 100kV Curtail	4,927,965	GS >100kV Curtailable	179,972	357,131	273,481	366,358	711,831	549,981	182,700	357,313	273,553	377,573	734,156	563,915	4,927,965	11,503
Streetlights	264,310	Street Lights	-	10,044	24,713	1,057	18,766	49,558	7,665	15,066	30,131	17,973	30,263	59,073	264,310	524
Thermal Generation	56,000,000	Totals	1,988,243	3,739,635	2,512,480	4,137,716	7,194,712	4,543,851	2,328,477	4,203,363	2,824,259	5,522,704	10,011,964	6,992,597	56,000,000	135,825
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	2.847	2.330	1.436	3.541	2.354	1.000	2.931	2.363	1.482	3.717	2.602	2.028		

Definition of Periods

Spring (April 1 to May 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Summer (June 1 to Sept 30)
Peak = 12:00 noon to 8:00 pm weekdays
Shoulder = 7:00 am to 12:00 noon weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Fall (Oct 1 to Nov 30)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Winter (December 1 to March 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

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 kWh 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 unweighted count of the 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.

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 in PCOSS13 (with no methodology changes).
- Schedule E2 summarizes the classified costs by allocation table in PCOSS13 (with methodology changes).

- Schedules E3 – E20 represent some of the main tables used to allocate classified costs.

SCHEDULE E1
PAGE 1 OF 2

Classified Costs by Allocation Table – No Methodology Changes

Prospective Cost Of Service Study
March 31, 2013
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Domestic & Export		256,189	151,533	270,785	5,925	684,432
E13	Generation - Domestic		10,784	18,788	40,102	-	69,673
			266,972	170,321	310,887	5,925	754,105
D13	Transmission - 2CP Domestic			-	2,259		2,259
D14	Transmission - 2CP Domestic & Export		71,686	63,398	64,269		199,352
			71,686	63,398	66,528	-	201,611
D21	Subtrans		4,553	23,250	29,185		56,989
D22	Subtrans	Stations	6,935	-			6,935
D23	Subtrans	Line	12,515	-			12,515
			24,004	23,250	29,185	-	76,439
D32	Dist. Plant Stn		17,651	22,084	35,838		75,572
D36	Dist. Plant	Lines	35,436	23,953	21,862		81,251
D40	Dist. Plant	S/E	11,320	12,629	5,959		29,908
			64,407	58,665	63,659	-	186,731
C23	Dist. Plant	Lines	23,624	15,969	14,575		54,167
C27	Dist. Plant	Services	3,085	2,086	1,903		7,074
C40	Dist. Plant	Meter Investment	1,536	5,196			6,732
C41	Dist. Plant	Meter Mtce.			2,233		2,233
			28,245	23,251	18,711	-	70,207
C10	Dist Serv	Cust Service - General	2,214	6,071	32,923	-	41,208
C11	Dist Serv	Cust Acct - Billings	1,560	2,344	23,196		27,100
C12	Dist Serv	Cust Acct - Collections	1,046	1,274	15,549		17,869
C13	Dist Serv	Marketing - R & D	34	41	503		578
C14	Dist Serv	Inspection	167	434	2,482		3,083
C15	Dist Serv	Meter Read	579	754	8,614		9,947
			5,600	10,918	83,267	-	99,785
	Total Allocated Costs		460,914	349,803	572,237	5,925	1,388,879

SCHEDULE E1
PAGE 2 OF 2

DIRECTS

C02	Generation	Diesel	717	1,489	6,653		8,860
E01	Generation	Export	22,167	9,286	173,463		204,915
			22,167	9,286	173,463	-	204,915
E01	Generation	SEP - GSM	193	129	194		516
E01	Generation	SEP - GSL 0-30kV	17	12	18		47
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	2,214	4,602	294		7,110
E01	Generation	GSS ND	1,769	3,811	65		5,646
E01	Generation	GSS Demand	1,845	4,012	78		5,935
E01	Generation	GSM	2,156	4,608	122		6,886
E01	Generation	GSL 0-30kV	1,135	2,353	67		3,554
E01	Generation	GSL 30-100kV excl Curt.	196	408	30		635
E01	Generation	GSL >100kV excl Curt.	724	1,399	103		2,227
E01	Generation	Street Lights	1	3	3		7
E01	Generation	Curtailment (GSL 30-100)	318	715	8	(639)	402
E01	Generation	Curtailment (GSL > 100)	3,033	6,753	71	(5,286)	4,571
			13,603	28,805	1,053	(5,925)	37,535
D04	Transmission	Export	-	-	1,614		1,614
D04	Transmission	SEP - GSM	51	45	46		142
D04	Transmission	SEP - GSL 0-30kV	5	4	4		13
			56	49	50	-	155
C01	Distribution	Lighting	3,075	4,096	7,041		14,212
C01	Distribution	Diesel	66	96	454		616
			3,141	4,192	7,496	-	14,828
	Total Directs		39,683	43,821	190,329	(5,925)	267,908
	Total		500,598	393,623	762,566	-	1,656,787
	Generation		303,459	209,900	492,056	-	1,005,415
	Transmission		71,742	63,447	68,192	-	203,381
	Subtransmission		24,004	23,250	29,185	-	76,439
	Distribution Plant		95,793	86,108	89,866	-	271,767
	Distribution Services		5,600	10,918	83,267	-	99,785
			500,598	393,623	762,566	-	1,656,787
	Energy		302,741	208,411	485,403	-	996,555
	Demand		160,153	145,363	161,036	-	466,551
	Customer		37,704	39,849	116,127	-	193,680
			500,598	393,623	762,566	-	1,656,787

SCHEDULE E2
PAGE 1 OF 2

Classified Costs by Allocation Table – With Methodology Changes

Prospective Cost Of Service Study
March 31, 2013
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Domestic & Export		262,192	160,774	347,507	5,925	776,398
E13	Generation - Domestic		4,780	9,547	23,002	-	37,329
			266,972	170,321	370,509	5,925	813,728
D13	Transmission - 2CP Domestic			-	2,259		2,259
D14	Transmission - 2CP Domestic & Export		71,686	63,398	64,269		199,352
			71,686	63,398	66,528	-	201,611
D21	Subtrans		4,402	23,184	29,185		56,771
D22	Subtrans	Stations	6,935	-			6,935
D23	Subtrans	Line	12,515	-			12,515
			23,852	23,184	29,185	-	76,221
D32	Dist. Plant Stn		17,651	22,083	35,838		75,572
D36	Dist. Plant	Lines	35,436	23,953	21,862		81,251
D40	Dist. Plant	S/E	11,320	12,629	5,959		29,908
			64,407	58,665	63,659	-	186,731
C23	Dist. Plant	Lines	23,624	15,969	14,575		54,167
C27	Dist. Plant	Services	3,085	2,086	1,903		7,074
C40	Dist. Plant	Meter Investment	1,536	5,196			6,732
C41	Dist. Plant	Meter Mtce.			2,233		2,233
			28,245	23,251	18,711	-	70,207
C10	Dist Serv	Cust Service - General	2,214	6,071	32,923	-	41,208
C11	Dist Serv	Cust Acct - Billings	1,560	2,344	23,196		27,100
C12	Dist Serv	Cust Acct - Collections	1,046	1,274	15,549		17,869
C13	Dist Serv	Marketing - R & D	34	41	503		578
C14	Dist Serv	Inspection	167	434	2,482		3,083
C15	Dist Serv	Meter Read	579	754	8,614		9,947
			5,600	10,918	83,267	-	99,785
	Total Allocated Costs		460,763	349,736	631,859	5,925	1,448,283

DIRECTS

C02	Generation	Diesel	717	1,489	6,653		8,860
E01	Generation	Export	22,167	9,286	113,841		145,293
			22,167	9,286	113,841	-	145,293
E01	Generation	SEP - GSM	193	129	194		516
E01	Generation	SEP - GSL 0-30kV	17	12	18		47
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	2,214	4,602	294		7,110
E01	Generation	GSS ND	1,769	3,811	65		5,646
E01	Generation	GSS Demand	1,845	4,012	78		5,935
E01	Generation	GSM	2,156	4,608	122		6,886
E01	Generation	GSL 0-30kV	1,135	2,353	67		3,554
E01	Generation	GSL 30-100kV excl Curt.	196	408	30		635
E01	Generation	GSL >100kV excl Curt.	724	1,399	103		2,227
E01	Generation	Street Lights	1	3	3		7
E01	Generation	Curtailment (GSL 30-100)	318	715	8	(639)	402
E01	Generation	Curtailment (GSL > 100)	3,033	6,753	71	(5,286)	4,571
			13,603	28,805	1,053	(5,925)	37,535
D04	Transmission	Export	-	-	1,614		1,614
D04	Transmission	SEP - GSM	51	45	46		142
D04	Transmission	SEP - GSL 0-30kV	5	4	4		13
D04	Transmission	GSL >100kV	151	67			218
			207	116	50	-	373
C01	Distribution	Lighting	3,075	4,096	7,041		14,212
C01	Distribution	Diesel	66	96	454		616
			3,141	4,192	7,496	-	14,828
	Total Directs		39,835	43,887	130,707	(5,925)	208,503
	Total		500,598	393,623	762,566	-	1,656,787
	Generation		303,459	209,901	492,056	-	1,005,416
	Transmission		71,893	63,514	68,192	-	203,599
	Subtransmission		23,852	23,184	29,185	-	76,221
	Distribution Plant		95,793	86,107	89,866	-	271,767
	Distribution Services		5,600	10,918	83,267	-	99,785
			500,598	393,623	762,566	-	1,656,787
	Energy		302,741	208,412	485,403	-	996,556
	Demand		160,153	145,362	161,036	-	466,551
	Customer		37,704	39,849	116,127	-	193,680
			500,598	393,623	762,566	-	1,656,787

12 PERIOD WEIGHTED ENERGY TABLE

(E12 Generation)

PURPOSE

This table is used to allocate costs associated with the energy component within the Generation function that are shared by the Domestic and Export classes.

METHOD

Table represents marginal cost ratios multiplied by twelve-period seasonal kWh 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 in various diurnal and seasonal periods.

12 PERIOD WEIGHTED ENERGY TABLE

(E13 Generation)

PURPOSE

This table is used to allocate costs associated with the energy component within the Generation function that are shared by the Domestic classes.

METHOD

Table represents marginal cost ratios multiplied by twelve-period seasonal kWh 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 in various diurnal and seasonal periods.

AVERAGE WINTER AND SUMMER COINCIDENT PEAK DEMAND TABLE (MW)

(D13 Transmission)

PURPOSE

This table is used to allocate costs associated with the demand component of the Transmission function that are shared among the Domestic classes.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using average of load research data for 2005/06 to 2010/11.

JUSTIFICATION

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.

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 that are shared by the Export and Domestic classes.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using average of load research data for 2005/06 to 2010/11

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/D22/D23 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with 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 the average of load research data from fiscal years 2005/06 to 2010/11.

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 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. Street and Sentinel Lighting are excluded from this table.

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. Street and Sentinel Lighting are excluded from this table.

METHOD

Number of customers adjusted for water heating.

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	5
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. 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, 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 forecast number of customers.

This table represents the number of customers weighted by the relative cost of 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
General Service Small	
Single Phase - Non-Demand	1
- Demand	14
Three Phase - Non-Demand	5
- Demand	23
General Service Medium	36
General Service Large	
0 - 30 kV	49
30 - 100 kV	224
>100 kV	233

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 forecast 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
General Service Small	
Single Phase - Non-Demand	1
- Demand	155
Three Phase - Non-Demand	50
- Demand	105
General Service Medium	215
General Service Large	
0 - 30 kV	530
30 - 100 kV	530
>100 kV	530

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

be averaged to produce class peak period usage totals. Curiously, the weighted energy (marginal cost) approach could readily have been retained had marginal cost included both energy and reserves instead of energy alone.

a) Please provide references to Manitoba Hydro documents that explain in detail how it implements (or implemented) this approach.

A. This response has been provided by Christensen Associates Energy Consulting.

Please see the attached Cost of Service document, Manitoba Hydro, *Prospective Cost of Service Study, For Fiscal Year Ending March 31, 2013*, July 2012., pp. 78-81. This part of the document describes allocators of generation and transmission costs. The former of these utilizes marginal cost ratios for four seasons, each divided into three pricing periods. The latter utilizes average summer and winter coincident peaks based on the top 50 hours of each season. (Reference page 57 for a description of the “top 50 hourly peaks during the winter and summer seasons”.)