Prospective Cost of Service Study

For Fiscal Year Ending March 31, 2014

Manitoba Hydro

Cost of Service Department
June 2013

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2014

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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.

Methodology used in PCOSS14

Manitoba Hydro has carried out PCOSS14 using largely the same methodology employed in PCOSS13, including enhancements resulting from Christensen Associates Energy Consultants ("CA") review of its Cost of Service Methodologies.

The following are the key aspects of the methodology employed in PCOSS14:

Export Class

PCOSS14 continues to recognize an Export Class. Additionally, PCOSS14 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 sales in excess of power purchases attracting water rentals fees and variable hydraulic generation O&M only.

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 believes 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.

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.

Thermal – Coal Generation

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, all the fixed and variable costs of the unit have been assigned entirely to the domestic classes in this study.

Non-Tariffable Transmission

In PCOSS14 a non-tariffable transmission subfunction has been added to capture costs of radial transmission and lines not otherwise eligible to include in the Open Access Transmission Tariff. In previous studies the cost of these facilities had been included in the subtransmission function.

Distribution Plant – Service Voltage

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.

PCOSS14

PCOSS14 has been prepared on the basis of the 2013/14 financial forecast from IFF12, which incorporates median water flows rather than the expected water flows used in PCOSS13. PCOSS14 includes revenues based on May 1, 2013 rates as approved in Order 43/13.

A comparison of the RCC's from PCOSS14 to PCOSS13 is provided in the table below:

CUSTOMER CLASS	PCOSS13	PCOSS14
Residential	99.2%	98.6%
GSS Non-Demand	107.6%	107.7%
GSS Demand	103.7%	104.9%
GSM	100.0%	100.0%
GSL 0 – 30 kV	93.3%	91.9%
GSL 30 – 100 kV	96.6%	101.7%
GSL > 100 kV	100.5%	101.0%
Area & Roadway Lighting	101.8%	99.7%

Net Export Revenue

PCOSS14 results in net export revenue of $34.4 million to be allocated to domestic customers. A summary of the costs assigned or allocated to the Export class is shown in the table below.

	(million $) PCOSS14

Gross Export Revenue	345.2
Less:	
Uniform Rates	23.5
Affordable Energy Fund Expenditures	12.8
Trading Desk	5.4
MISO Fees	1.7
NEB Charges	1.0
Purchased Power and Transmission (excl wind)	90.3
Allocated G&T incl Water Rentals and Wind (dependable exports)	166.4
Assigned Water Rentals (opportunity exports)	8.8
Variable Hydraulic Generation O&M (opportunity exports)	0.9
Equals: Net Export Revenue	34.4

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SECTION A: COST OF SERVICE METHODOLOGY

Cost of Service History

Manitoba Hydro has conducted Cost of Service Studies since the mid 1970s. While significant changes have occurred on an evolutionary basis, cost of service studies filed with previous Rate Applications 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 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.

Methodology used in PCOSS14

Manitoba Hydro has carried out PCOSS14 using largely the same methodology employed in PCOSS13, including enhancements resulting from Christensen Associates Energy Consultants ("CA") review of its Cost of Service Methodologies.

The following are the key aspects of the methodology employed in PCOSS14:

Export Class

PCOSS14 continues to recognize an Export Class. Additionally, PCOSS14 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 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.

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 believes 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.

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

Thermal – Coal Generation

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, all the fixed and variable costs of the unit have been assigned entirely to the domestic classes in this study.

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.

Non-Tariffable Transmission

In PCOSS14 a non-tariffable transmission subfunction has been added to capture costs of radial transmission and lines not otherwise eligible to include in the Open Access Transmission Tariff. In previous studies the cost of these facilities has been included in the subtransmission function.

PCOSS13 included direct assignment of dedicated radial taps serving GSL >100 kV customers. The assignment recognized the cost responsibility of the customers who do not share subtransmission costs, and would not otherwise be charged the cost of the transmission lines that serve them. In PCOSS14 these taps are now included in non-tariffable transmission, which is shared by all classes including the >100 kV customers. Since the direct assignment of radial taps added additional complexity with inconsequential impact on revenue cost coverage ratios, the direct assignment to the GSL >100 kV class has not been included in PCOSS14.

Distribution Plant – Service Voltage

The customer and demand factors for GSL 0-30 kV 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.

Assignment of DSM Costs

PCOSS14 assigns program costs to the customer classes in the same manner as carried out in PCOSS13. DSM is not driven by export sales and the costs should be assigned to the customer classes benefiting from the DSM programming. Assignment in PCOSS14 is based on class participation over ten years, as done in PCOSS13, in order to match the capitalization and subsequent amortization of program costs, rather than a single year as used in PCOSS11.

Treatment of Diesel Funding Agreement in PCOSS14

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 PCOSS14, 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 which according to the terms of the Diesel Funding Agreement will be fully amortized by March 31, 2014.

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SECTION B: SUMMARY RESULTS

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PCOSS14 has been prepared on the basis of the financial forecast for 2013/14 from IFF12 and largely followed the same methodology approach as reflected in PCOSS13. PCOSS14 includes revenues based on May 1, 2013 rates as approved in Order 43/13.

Median Water Flow Conditions

PCOSS14 has been prepared on the basis of the 2013/14 financial forecast from IFF12, which incorporates median water flows rather than the expected water flows used in PCOSS13. Notwithstanding the last forecast, the use of median water flows is the customary approach for the test year used in the PCOSS. Median flows in PCOSS14 are higher than the expected flows from PCOSS13, which will generally result in increased opportunity export sales.

International Financial Reporting Standards (IFRS)

IFF12 is based on the September 19, 2012 ruling by the Canadian Accounting Standards Board (AcSB) to extend the optional transition date for rate-regulated entities an additional year to January 1, 2014. This ruling was made in consideration of the recent commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting. Manitoba Hydro will adopt the optional transition date deferral and will be transitioning to IFRS for its 2014/15 fiscal period therefore the impacts of IFRS are not reflected in the 2013/14 test year used for PCOSS14.

Depreciation Study

Depreciation rates used in PCOSS14 are unchanged from those used in PCOSS13.

PCOSS14 Results

A comparison of the RCC's from PCOSS14 to PCOSS13 is provided in the table below:

CUSTOMER CLASS	PCOSS13	PCOSS14
Residential	99.2%	98.6%
GSS Non-Demand	107.6%	107.7%

GSS Demand	103.7%	104.9%
GSM	100.0%	100.0%
GSL 0 – 30 kV	93.3%	91.9%
GSL 30 – 100 kV	96.6%	101.7%
GSL > 100 kV	100.5%	101.0%
Area & Roadway Lighting	101.8%	99.7%

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%. Schedule B1 outlines the customer class RCC;

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

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

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Revenue Cost Coverage Analysis

SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	611,858	588,630	14,948	603,578	98.6%
General Service - Small Non Demand	128,193	135,035	3,041	138,076	107.7%
General Service - Small Demand	132,701	136,080	3,142	139,222	104.9%
General Service - Medium	191,443	186,797	4,569	191,366	100.0%
General Service - Large 0 - 30kV	94,925	84,956	2,260	87,216	91.9%
General Service - Large 30-100kV*	58,236	57,808	1,411	59,218	101.7%
General Service - Large >100kV*	191,869	189,258	4,599	193,856	101.0%
*Includes Curtailment Customers					
SEP	968	826	-	826	85.4%
Area & Roadway Lighting	21,866	21,630	161	21,791	99.7%
Total General Consumers	1,432,060	1,401,019	34,131	1,435,150	100.2%
Diesel	9,948	6,612	246	6,858	68.9%
Export	310,856	345,233	(34,377)	310,856	100.0%
Total System	1,752,864	1,752,864	-	1,752,864	100.0%

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Customer, Demand, Energy Cost Analysis

SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy mWh	ENERGY Unit Cost ¢/kWh
Residential	125,710	486,987	21.51	206,996	0%	n/a	n/a	264,371	7,404,453	6.37 **
GS Small - Non Demand	25,036	53,778	38.80	39,575	0%	n/a	n/a	60,544	1,605,511	6.24 **
GS Small - Demand	8,507	12,492	56.75	45,970	38%	2,390	7.29	75,032	2,047,715	5.06
General Service - Medium	7,439	1,974	314.05	66,170	87%	7,302	7.92	113,197	3,174,662	3.83
General Service - Large <30kV	3,742	288	n/a	29,255	100%	4,042	8.16 *	59,629	1,702,481	3.50
General Service - Large 30-100kV	2,587	40	n/a	11,951	100%	2,894	5.02 *	42,279	1,327,210	3.19
General Service - Large >100kV	2,390	16	n/a	29,475	100%	8,409	3.79 *	155,406	4,903,742	3.17
SEP	326	29	935.95	132	0%	n/a	n/a	509	26,500	2.42 **
Area & Roadway Lighting	16,622	155,024	8.94	2,329	0%	n/a	n/a	2,749	100,487	5.05 **
Total General Consumers	192,358	710,628		431,853		25,038		773,717	22,292,761	
Diesel	229	755	25.27	343	0%	n/a	n/a	9,130	13,754	68.88 **
Export	n/a	n/a	n/a	31,054	0%	n/a	n/a	279,802	9,013,000	3.45 ***
Total System	192,587	711,383		463,251		25,038		1,062,649	31,319,515	

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

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Functional Breakdown

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	597,077	264,371	44.3%	67,889	11.4%	32,316	5.4%	69,396	11.6%	163,105	27.3%
General Service - Small Non Demand	125,155	60,544	48.4%	14,493	11.6%	5,827	4.7%	17,636	14.1%	26,656	21.3%
General Service - Small Demand	129,509	75,032	57.9%	17,128	13.2%	6,700	5.2%	4,214	3.3%	26,434	20.4%
General Service - Medium	186,807	113,197	60.6%	26,290	14.1%	9,265	5.0%	6,414	3.4%	31,641	16.9%
General Service - Large <30kV	92,627	59,629	64.4%	13,581	14.7%	4,628	5.0%	3,518	3.8%	11,270	12.2%
General Service - Large 30-100kV	56,816	42,279	74.4%	8,417	14.8%	3,534	6.2%	2,517	4.4%	69	0.1%
General Service - Large >100kV	187,270	155,406	83.0%	29,475	15.7%	0	0.0%	2,361	1.3%	29	0.0%
SEP	968	509	52.6%	132	13.7%	0	0.0%	309	31.9%	17	1.7%
Area & Roadway Lighting	21,700	2,798	12.9%	449	2.1%	446	2.1%	543	2.5%	17,464	80.5%
Total General Consumers	1,397,928	773,766	55.4%	177,855	12.7%	62,716	4.5%	106,907	7.6%	276,685	19.8%
Diesel	9,702	9,130	94.1%	0	0.0%	0	0.0%	0	0.0%	572	5.9%
Export	310,856	279,802	90.0%	31,054	10.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,718,487	1,062,698	61.8%	208,909	12.2%	62,716	3.6%	106,907	6.2%	277,257	16.1%

Net Export Revenue

PCOSS14 results in net export revenue of $34.4 million to be allocated to domestic customers. A summary of the costs assigned or allocated to the Export class is shown in the table below.

	(million $) PCOSS14
Gross Export Revenue	345.2
Less:	
Uniform Rates	23.5
Affordable Energy Fund Expenditures	12.8
Trading Desk	5.4
MISO Fees	1.7
NEB Charges	1.0
Purchased Power and Transmission (excl wind)	90.3
Allocated G&T incl Water Rentals and Wind (dependable exports)	166.4
Assigned Water Rentals (opportunity exports)	8.8
Variable Hydraulic Generation O&M (opportunity exports)	0.9
Equals: Net Export Revenue	34.4

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 2013/14 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), and a share of the communication facilities, administration buildings and general equipment.

- Transmission Function – This function includes all the high voltage (100 kV and higher) grid transmission lines. In PCOSS14 a non-tariffable transmission subfunction has been added to capture costs of radial transmission and lines not otherwise eligible to include in Manitoba Hydro's Open Access Transmission Tariff, which would previously be included in the subtransmission function. Although the costs are functionalized separately, the subfunctions are combined for the purpose of allocation.

In addition to the transmission lines above, this function also includes: Dorsey Converter Station, the high voltage portion of substations, and a share of the communication facilities, administration buildings, general equipment and substation transformers in stock.

- Ancillary Services Function – Ancillary Services include specific items 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 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.

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, 2012, is first functionalized.

Functionalized gross plant investment for 2012 is set forth in Schedule C1. Plant investment is functionalized into the following areas:

- Generation
- Transmission (Tariffable, Non-Tariffable)
- 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.

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.

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. Schedule C2 details the functionalized gross investment forecast for the fiscal year ending March 31, 2014.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year ending March 31, 2014. 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 2014.

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 PCOSS14. 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 2012/13 and 2013/14 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, 2014 (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 2013/14 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 PCOSS14 the revenue adjustment is $23.5 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	$ 2,952,647
General Service Small-Non-Demand	$ 1,147,015
General Service Small-Demand	$ 1,716,730
General Service Medium	$ 1,693,852
General Service Large:	
0 - 30 kV	$ 674,118
30 - 100 kV	$ 256,079
> 100 kV	$ 177,810
Total DSM	**$ 8,618,251**

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.

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
MARCH 31, 2012

ASSET CLASS	TOTAL GROSS INVESTMENT	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	Direct Allocation	
			Tariffable	Non-Tariffable		Plant	Services		Lighting	Diesel
GENERATION	5,188,284,863	5,188,284,863								
-Thermal	437,432,384	437,432,384								
DIESEL	48,822,371									48,822,371
SUBSTATION	1,382,508,310	16,513,235	426,736,838	7,156,368	254,238,835	606,156,149		71,706,884		
- HVDC	1,269,655,039	609,294,816	660,360,223							
TRANSMISSION	665,731,338		476,167,676	189,563,662						
- HVDC	190,493,761	190,493,761								
DISTRIBUTION	2,330,951,587					2,169,107,563			158,425,204	3,418,820
SUBTRANSMISSION	281,456,600				281,456,600					
TRANSFORMERS										
- SUBSTATION	22,043,908		7,268,047	121,885	4,330,116	10,323,860				
- DISTRIBUTION	12,566,010					12,566,010				
METERS	48,768,550					48,768,550				
BUILDINGS	451,148,301	193,520,628	61,275,677	7,679,955	20,826,308	75,320,153	84,744,392		7,159,012	622,176
COMMUNICATION	338,780,687	177,755,532	53,074,097	6,652,015	28,175,870	65,238,758		7,884,416		
GENERAL EQUIPMENT	176,636,517	75,873,091	24,024,183	3,011,059	8,165,312	29,530,561	33,225,497		2,806,814	
SUBTOTAL	12,845,280,226	6,889,168,311	1,708,906,742	214,184,943	597,193,041	3,017,011,605	117,969,888	79,591,299	168,391,029	52,863,367
MOTOR VEHICLES	185,286,920									
TOTAL FIXED ASSETS	13,030,567,146	6,889,168,311	1,708,906,742	214,184,943	597,193,041	3,017,011,605	117,969,888	79,591,299	168,391,029	52,863,367

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Total	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Tariffable	Non-Tariffable		Plant	Services		Lighting	Diesel
GENERATION	7,446,602,083	7,446,602,083	-	-	-	-	-	-	-	-
-Thermal	447,189,923	447,189,923	-	-	-	-	-	-	-	-
DIESEL	56,214,791	-	-	-	-	-	-	-	-	56,214,791
SUBSTATION	1,753,370,678	18,483,248	483,819,340	117,126,811	327,944,496	723,725,193	-	82,271,590	-	-
- HVDC	1,338,703,165	638,569,888	700,133,277	-	-	-	-	-	-	-
TRANSMISSION	824,028,643	-	499,505,360	324,523,283	-	-	-	-	-	-
- HVDC	196,311,067	196,311,067	-	-	-	-	-	-	-	-
DISTRIBUTION	2,657,872,792	-	-	-	-	2,471,476,729	-	-	182,959,621	3,436,442
SUBTRANSMISSION	323,017,721	-	-	-	323,017,721	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	22,043,908	-	7,268,047	121,885	4,330,116	10,323,860	-	-	-	-
- DISTRIBUTION	12,566,010	-	-	-	-	12,566,010	-	-	-	-
METERS	54,700,852	-	-	-	-	54,700,852	-	-	-	-
BUILDINGS	462,906,420	198,571,253	62,874,889	7,880,392	21,369,847	77,285,906	86,956,105	-	7,345,852	622,176
COMMUNICATION	377,947,416	198,306,003	59,210,039	7,421,060	31,433,307	72,781,067	-	8,795,940	-	-
GENERAL EQUIPMENT	242,122,108	104,002,010	32,930,823	4,127,368	11,192,491	40,478,616	45,543,398	-	3,847,402	-
SUBTOTAL	16,215,597,577	9,248,035,474	1,845,741,776	461,200,798	719,287,978	3,463,338,234	132,499,503	91,067,529	194,152,875	60,273,409
MOTOR VEHICLES	219,125,569									
TOTAL FIXED ASSETS	16,434,723,146	9,248,035,474	1,845,741,776	461,200,798	719,287,978	3,463,338,234	132,499,503	91,067,529	194,152,875	60,273,409

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF ACCUMULATED DEPRECIATION
FORECAST YEAR ENDING MARCH 31, 2014

			Transmission			Distribution			DIRECT ALLOCATIONS	
Asset Class	Accum Depn by Asset Class	Generation	Tariffable	Non-Tariffable	Sub Trans	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	1,858,014,079	1,858,014,079	-	-	-	-	-	-	-	-
-Thermal	255,066,046	255,066,046	-	-	-	-	-	-	-	-
DIESEL	38,522,480	-	-	-	-	-	-	-	-	38,522,480
SUBSTATION	594,484,248	12,333,451	153,135,712	6,595,665	128,419,983	258,367,636	-	35,631,802	-	-
- HVDC	790,296,399	390,012,812	400,283,587	-	-	-	-	-	-	-
TRANSMISSION	243,290,657	-	183,129,636	60,161,021	-	-	-	-	-	-
- HVDC	86,346,950	86,346,950	-	-	-	-	-	-	-	-
DISTRIBUTION	1,042,663,842	-	-	-	-	952,833,454	-	-	87,452,046	2,378,342
SUBTRANSMISSION	121,740,195	-	-	-	121,740,195	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	14,657,307	-	4,157,243	49,453	3,447,433	7,003,178	-	-	-	-
- DISTRIBUTION	4,239,323	-	-	-	-	4,239,323	-	-	-	-
METERS	21,104,651	-	-	-	-	21,104,651	-	-	-	-
BUILDINGS	63,836,234	27,330,492	8,653,829	1,084,623	2,941,254	10,637,299	11,968,264	-	1,011,051	209,422
COMMUNICATION	180,774,050	93,277,486	27,638,175	2,547,718	17,679,133	32,972,014	-	6,659,525	-	-
GENERAL EQUIPMENT	118,973,497	51,104,308	16,181,485	2,028,098	5,499,745	19,890,305	22,379,028	-	1,890,529	-
SUBTOTAL	5,434,009,958	2,773,485,624	793,179,666	72,466,579	279,727,742	1,307,047,859	34,347,291	42,291,326	90,353,627	41,110,244
MOTOR VEHICLES	92,731,972									
TOTAL ACCUM DEPRECIATION	5,526,741,930	2,773,485,624	793,179,666	72,466,579	279,727,742	1,307,047,859	34,347,291	42,291,326	90,353,627	41,110,244

SCHEDULE C4

Functionalization of Capital Contributions Unamortized Balance

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
UNAMORITIZED BALANCE
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Unamortized Capital Contribution	Generation	Transmission Tariffable	Transmission Non-Tariffable	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	285,805	285,805	-	-	-	-	-	-	-	-
-Thermal	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-
SUBSTATION	23,733,572	6,271	3,566,935	2,718	2,375,147	17,744,293	-	38,207	-	-
- HVDC	685,327	-	685,327	-	-	-	-	-	-	-
TRANSMISSION	65,996,875	-	5,022,053	60,974,822	-	-	-	-	-	-
- HVDC	51,031	51,031	-	-	-	-	-	-	-	-
DISTRIBUTION	216,552,856	-	-	-	-	182,432,571	-	-	33,791,020	329,265
SUBTRANSMISSION	12,816,382	-	-	-	12,816,382	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	-	-	-	-	-	-	-	-	-	-
BUILDINGS	-	-	-	-	-	-	-	-	-	-
COMMUNICATION	368,143	193,162	57,674	7,229	30,618	70,893	-	8,568	-	-
GENERAL EQUIPMENT	168,458	72,360	22,912	2,872	7,787	28,163	31,687	-	2,677	-
SUBTOTAL	320,658,449	608,629	9,354,901	60,987,640	15,229,934	200,275,921	31,687	46,775	33,793,697	329,265
MOTOR VEHICLES	-									
TOTAL UNAMORTIZED CONTRIBS	320,658,449	608,629	9,354,901	60,987,640	15,229,934	200,275,921	31,687	46,775	33,793,697	329,265

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
ANNUAL AMORTIZATION
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Annual Amortization Contribution	Generation	Transmission		Sub - Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Tariffable	Non-Tariffable		Plant	Services		Lighting	Diesel
GENERATION	14,095	14,095								
-Thermal	-									
DIESEL	-									
SUBSTATION	1,253,451	-	163,231	-	104,278	985,352		590		
- HVDC	12,125		12,125							
TRANSMISSION	1,352,803		28,843	1,323,960						
- HVDC	820	820								
DISTRIBUTION	5,300,754					3,288,262			1,983,514	28,978
SUBTRANSMISSION	433,855				433,855					
TRANSFORMERS										
- SUBSTATION	-									
- DISTRIBUTION	-									
METERS	-									
BUILDINGS	-									
COMMUNICATION	17,079	8,961	2,676	335	1,420	3,289	-	397	-	
GENERAL EQUIPMENT	18,226	7,829	2,479	311	843	3,047	3,428	-	290	
SUBTOTAL	8,403,208	31,705	209,354	1,324,606	540,396	4,279,950	3,428	988	1,983,804	28,978
MOTOR VEHICLES	-									
TOTAL ANNUAL AMORT.	8,403,208	31,705	209,354	1,324,606	540,396	4,279,950	3,428	988	1,983,804	28,978

2014 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2014
Functionalization of Depreciation Costs

SCC Description	Depreciation	Generation	Trans - Tariffable	Trans - Non-Tariffable	Subtransmission	Distribution Plant	Customer Service	Ancilary Services	Diesel	Street Lighting	Exports
Common Generation Costs	47,409,234	34,097,209									13,312,025
Generating Station Costs	17,204,201	17,204,201									-
Other Generation Related Costs	409,875	409,875	-		-	-	-		-	-	
Dedicated Gen. Facilities	17,614,076	17,614,076							-	-	-
Hydraulic Generating Stations	82,981,992	82,981,992									
Other Hydraulic Generation Related Cost	18,534,808	18,534,808									
Hydraulic Generation Costs	101,516,800	101,516,800									
Thermal Generating Station	18,516,208	18,516,208									-
Non-Dedicated Gen. Facilities	120,033,007	120,033,007									-
Generation Facilities Costs	137,647,083	137,647,083							-	-	-
Purchased Power/Export Costs	-	-									-
Generation Facilities & Costs	***185,056,318***	***171,744,293***							*-*	*-*	***13,312,025***
Common Trans. Costs/Revenues	3,003,512	-	2,149,482	854,030	-						-
Generation Switching Stations	4,309,593	447,848	2,153,668	1,614,174	-	-	-	93,903			
HVDC & Collector Facilities	56,294,018	30,196,092	26,097,926	-							
Networked AC Facilities	12,875,610	-	10,723,047	1,690,176	-	-	-	462,387			
Generation Access Transmission	73,479,220	30,643,940	38,974,641	3,304,350	-	-	-	556,289			
Regional Networked Trans.	10,193,893	-	7,005,244	1,590,393	-	-	-	1,598,256			
Transmission Common	2,244,697	-	1,978,448	266,249	-	-	-	-	-		
Transmission Facilities/Costs	***88,921,323***	***30,643,940***	***50,107,816***	***6,015,022***	*-*	*-*	*-*	***2,154,545***	*-*		*-*
Common Subtransmission Costs	691,802	-	-	-	691,802						
Subtrans. Facilities & Costs	***20,161,893***	*-*	***144,070***	***1,719,629***	***16,768,117***	***1,530,077***	*-*	*-*	*-*	*-*	*-*
Dist. Facilities & Costs	***85,224,517***	*-*	*-*	*-*	*-*	***81,298,769***	*-*	*-*	*-*	***3,925,748***	*-*
Customer Service Costs	***11,068,263***	*-*	*-*	*-*	*-*	*-*	***11,068,263***		*-*	*-*	*-*
Isolated Diesel Facilities	***3,522,001***	***1,790,558***	*-*	*-*	*-*	***80,147***	*-*	*-*	***1,651,296***		
Communication & Control System	***27,013,525***	***13,600,294***	***3,080,447***	***369,782***	***3,235,503***	***4,997,953***	*-*	***1,729,546***	*-*	*-*	*-*
	420,967,839	**217,779,084**	**53,332,332**	**8,104,433**	**20,003,620**	**87,906,945**	**11,068,263**	**3,884,092**	**1,651,296**	**3,925,748**	**13,312,025**

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF NET INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Net Investment	Generation	Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
			Tariffable	Non-Tariffable	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	5,588,302,199	5,588,302,199	-	-	-	-	-	-	-	-
-Thermal	192,123,877	192,123,877	-	-	-	-	-	-	-	-
DIESEL	17,692,311	-	-	-	-	-	-	-	-	17,692,311
SUBSTATION	1,135,152,858	6,143,525	327,116,693	110,528,428	197,149,367	447,613,264	-	46,601,581	-	-
- HVDC	547,721,439	248,557,076	299,164,363	-	-	-	-	-	-	-
TRANSMISSION	514,741,111	-	311,353,672	203,387,439	-	-	-	-	-	-
- HVDC	109,913,086	109,913,086	-	-						
DISTRIBUTION	1,398,656,094	-	-	-	-	1,336,210,704	-	-	61,716,555	728,835
SUBTRANSMISSION	188,461,144	-	-	-	188,461,144	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	7,386,601	-	3,110,804	72,432	882,683	3,320,682	-	-	-	-
- DISTRIBUTION	8,326,687	-	-	-	-	8,326,687	-	-	-	-
METERS	33,596,201	-	-	-	-	33,596,201	-	-	-	-
BUILDINGS	399,070,186	171,240,761	54,221,060	6,795,769	18,428,593	66,648,607	74,987,841	-	6,334,801	412,754
COMMUNICATION	196,805,223	104,835,355	31,514,190	4,866,113	13,723,556	39,738,161	-	2,127,847	-	-
GENERAL EQUIPMENT	122,980,153	52,825,342	16,726,427	2,096,398	5,684,959	20,560,148	23,132,683	-	1,954,196	-
SUBTOTAL	10,460,929,170	6,473,941,221	1,043,207,209	327,746,579	424,330,301	1,956,014,455	98,120,525	48,729,428	70,005,551	18,833,900
MOTOR VEHICLES	126,393,597									
TOTAL NET INVESTMENT	10,587,322,767	6,473,941,221	1,043,207,209	327,746,579	424,330,301	1,956,014,455	98,120,525	48,729,428	70,005,551	18,833,900

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2014

			Transmission			Distribution			DIRECT ALLOCATIONS	
Asset Class	Rate Base Investment	Generation	Tariffable	Non-Tariffable	Sub-Transmission	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	5,497,416,452	5,497,416,452	-	-	-	-	-	-	-	-
-Thermal	198,388,879	198,388,879	-	-	-	-	-	-	-	-
DIESEL	19,486,692	-	-	-	-	-	-	-	-	19,486,692
SUBSTATION	1,108,110,322	5,311,085	321,551,017	111,991,847	195,096,146	429,943,555	-	44,216,671	-	-
- HVDC	551,053,860	251,001,414	300,052,445	-	-	-	-	-	-	-
TRANSMISSION	534,921,489	-	325,690,146	209,231,343	-	-	-	-	-	-
- HVDC	111,471,563	111,471,563	-	-	-	-	-	-	-	-
DISTRIBUTION	1,387,373,079	-	-	-	-	1,325,492,751	-	-	61,128,693	751,635
SUBTRANSMISSION	189,836,480	-	-	-	189,836,480	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	7,664,394	-	3,202,395	73,968	937,250	3,450,782	-	-	-	-
- DISTRIBUTION	8,486,555	-	-	-	-	8,486,555	-	-	-	-
METERS	34,059,134	-	-	-	-	34,059,134	-	-	-	-
BUILDINGS	399,173,432	171,282,397	54,234,244	6,797,421	18,433,074	66,664,812	75,006,074	-	6,336,341	419,071
COMMUNICATION	208,186,138	110,806,831	33,297,148	5,089,580	14,670,089	41,929,776	-	2,392,714	-	-
GENERAL EQUIPMENT	195,867,142	84,133,483	26,639,724	3,338,876	9,054,280	32,745,588	36,842,795	-	3,112,395	-
SUBTOTAL	10,451,495,610	6,429,812,105	1,064,667,119	336,523,034	428,027,319	1,942,772,952	111,848,869	46,609,386	70,577,428	20,657,397
MOTOR VEHICLES	122,425,383									
Total Rate Base Investment	10,573,920,993	6,429,812,105	1,064,667,119	336,523,034	428,027,319	1,942,772,952	111,848,869	46,609,386	70,577,428	20,657,397

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Interest & Reserve Expense	Generation	Transmission Tariffable	Transmission Non-Tariffable	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	243,441,120	243,441,120	-	-	-	-	-	-	-	-
-THERMAL	8,785,220	8,785,220	-	-	-	-	-	-	-	-
DIESEL	862,926	-	-	-	-	-	-	-	-	862,926
SUBSTATION	49,070,253	235,190	14,239,187	4,959,315	8,639,408	19,039,114	-	1,958,039	-	-
- HVDC	24,402,221	11,115,051	13,287,169	-	-	-	-	-	-	-
TRANSMISSION	23,687,834	-	14,422,479	9,265,355	-	-	-	-	-	-
- HVDC	4,936,276	4,936,276	-	-	-	-	-	-	-	-
DISTRIBUTION	61,436,797	-	-	-	-	58,696,561	-	-	2,706,951	33,284
SUBTRANSMISSION	8,406,495	-	-	-	8,406,495	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	339,401	-	141,811	3,276	41,504	152,810	-	-	-	-
- DISTRIBUTION	375,809	-	-	-	-	375,809	-	-	-	-
METERS	1,508,235	-	-	-	-	1,508,235	-	-	-	-
BUILDINGS	17,676,526	7,584,868	2,401,645	301,009	816,269	2,952,106	3,321,481	-	280,591	18,558
COMMUNICATION	9,219,070	4,906,839	1,474,492	225,381	649,633	1,856,769	-	105,956	-	-
GENERAL EQUIPMENT	8,673,550	3,725,668	1,179,682	147,855	400,949	1,450,067	1,631,503	-	137,826	-
SUBTOTAL	462,821,731	284,730,232	47,146,466	14,902,190	18,954,258	86,031,471	4,952,984	2,063,995	3,125,368	914,768
MOTOR VEHICLES	-									
Total Interest Exp Allocated	462,821,731	284,730,232	47,146,466	14,902,190	18,954,258	86,031,471	4,952,984	2,063,995	3,125,368	914,768

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2014

Asset Class	Rate Based for Capital Tax	Generation	Transmission Tariffable	Transmission Non-Tariffable	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	5,781,387,592	5,781,387,592	-	-	-	-	-	-	-	-
-THERMAL	192,123,877	192,123,877	-	-	-	-	-	-	-	-
DIESEL	22,110,604	-	-	-	-	-	-	-	-	22,110,604
SUBSTATION	1,135,962,785	6,153,199	327,366,693	110,532,620	197,298,310	447,968,374	-	46,643,590	-	-
- HVDC	547,721,439	248,557,076	299,164,363	-	-	-	-	-	-	-
TRANSMISSION	529,612,334	-	321,990,388	207,621,946	-	-	-	-	-	-
- HVDC	109,913,086	109,913,086	-	-	-	-	-	-	-	-
DISTRIBUTION	1,427,207,749	-	-	-	-	1,362,818,970	-	-	63,659,944	728,835
SUBTRANSMISSION	193,477,832	-	-	-	193,477,832	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	7,386,601	-	3,110,804	72,432	882,683	3,320,682	-	-	-	-
- DISTRIBUTION	8,326,687	-	-	-	-	8,326,687	-	-	-	-
METERS	33,596,201	-	-	-	-	33,596,201	-	-	-	-
BUILDINGS	399,135,701	171,268,903	54,229,971	6,796,885	18,431,622	66,659,560	75,000,165	-	6,335,842	412,754
COMMUNICATION	199,974,942	106,498,482	32,010,765	4,928,351	13,987,177	40,348,551	-	2,201,616	-	-
GENERAL EQUIPMENT	196,695,674	84,489,374	26,752,412	3,353,000	9,092,580	32,884,105	36,998,643	-	3,125,560	-
SUBTOTAL	10,784,633,105	6,700,391,589	1,064,625,397	333,305,234	433,170,203	1,995,923,131	111,998,808	48,845,206	73,121,346	23,252,193
MOTOR VEHICLES	-									
Rate Base for Capital Tax	10,784,633,105	6,700,391,589	1,064,625,397	333,305,234	433,170,203	1,995,923,131	111,998,808	48,845,206	73,121,346	23,252,193

2014 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2014

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Capital Tax	Generation	Tariffable	Non-Tariffable	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	33,375,046	33,375,046	-	-	-	-	-	-	-	-
-Thermal	1,109,101	1,109,101	-	-	-	-	-	-	-	-
DIESEL	127,641	-	-	-	-	-	-	-	-	127,641
SUBSTATION	6,557,735	35,521	1,889,837	638,088	1,138,972	2,586,051	-	269,266	-	-
- HVDC	3,161,910	1,434,881	1,727,029	-	-	-	-	-	-	-
TRANSMISSION	3,057,369	-	1,858,800	1,198,569	-	-	-	-	-	-
- HVDC	634,511	634,511	-	-	-	-	-	-	-	-
DISTRIBUTION	8,239,047	-	-	-	-	7,867,341	-	-	367,499	4,207
SUBTRANSMISSION	1,116,917	-	-	-	1,116,917	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	42,642	-	17,958	418	5,096	19,170	-	-	-	-
- DISTRIBUTION	48,069	-	-	-	-	48,069	-	-	-	-
METERS	193,946	-	-	-	-	193,946	-	-	-	-
BUILDINGS	2,304,148	988,709	313,061	39,237	106,403	384,815	432,964	-	36,576	2,383
COMMUNICATION	1,154,424	614,799	184,793	28,451	80,746	232,926	-	12,710	-	-
GENERAL EQUIPMENT	1,135,493	487,744	154,437	19,356	52,490	189,835	213,587	-	18,043	-
SUBTOTAL	62,258,000	38,680,313	6,145,916	1,924,119	2,500,624	11,522,152	646,552	281,976	422,118	134,231
MOTOR VEHICLES	-									
Capital Tax Allocation	62,258,000	38,680,313	6,145,916	1,924,119	2,500,624	11,522,152	646,552	281,976	422,118	134,231

2014 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2014
Functionalization of Operating Costs

SCC Description	Operating	Generation	Trans - Tariffable	Trans - Non-Tariffable	Subtransmission	Distribution Plant	Customer Service	Ancilary Services	Diesel	Street Lighting	Exports
Common Generation Costs	33,008,218	28,102,071									4,906,147
Generating Station Costs	49,993,457	49,993,457									-
Other Generation Related Costs	1,131,784	1,131,784	-		-	-	-		-	-	
Dedicated Gen. Facilities	51,125,241	51,125,241							-	-	-
Hydraulic Generating Stations	163,464,500	163,464,500									
Other Hydraulic Generation Related Cost	17,490,953	17,490,953									
Hydraulic Generation Costs	180,955,453	180,955,453									
Thermal Generating Station	33,152,240	33,152,240									-
Non-Dedicated Gen. Facilities	214,107,694	214,107,694									-
Generation Facilities Costs	265,232,934	265,232,934							-	-	-
Purchased Power/Export Costs	156,256,000	64,996,000									91,260,000
Generation Facilities & Costs	***454,497,152***	***358,331,005***							-	-	***96,166,147***
Common Trans. Costs/Revenues	26,904,476	594,618	19,912,810	4,700,798	-						1,696,250
Generation Switching Stations	2,536,888	328,399	2,206,489	2,000							
HVDC & Collector Facilities	50,697,543	30,252,408	20,445,135	-							
Networked AC Facilities	4,704,153	-	4,567,468	136,685	-						
Generation Access Transmission	57,938,584	30,580,807	27,219,092	138,685	-						
Regional Networked Trans.	842,177	-	592,746	249,431	-	-					
Transmission Common	14,580,666	-	13,258,196	668,543	-	-	-	653,928	-		
Transmission Facilities/Costs	***100,265,903***	***31,175,425***	***60,982,844***	***5,757,457***	-	-	-	***653,928***	-		***1,696,250***
Common Subtransmission Costs	6,563,653	-	-	-	6,563,653						
Subtrans. Facilities & Costs	***31,118,005***	-	-	***1,915,905***	***19,601,346***	***9,600,754***	-		-	-	-
Dist. Facilities & Costs	***78,170,313***	-	-	-	-	***70,319,865***	-		-	***7,850,448***	-
Customer Service Costs	***92,929,231***	-	-	-	-	-	***92,929,231***		-	-	-
Isolated Diesel Facilities	***7,247,756***	-	-	-	-	-	-		***7,247,756***		
Communication & Control System	***12,203,644***	***5,886,525***	***694,759***	***63,818***	***2,771,875***	***779,452***	-	***2,007,216***	-	-	-
	783,283,571	**398,042,493**	**63,365,898**	**7,892,260**	**22,837,769**	**82,594,175**	**92,929,231**	**2,661,143**	**7,247,756**	**7,850,448**	**97,862,397**

Adjusted Revenue including DSM Reduction at Approved Rates

2014 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ APPROVED RATES
For Year Ended March 31, 2014

Revenue Class	Unadjusted Revenue	1.5% Deferral Per BO 43/13	Allowable Revenue Per BO 43/13	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
<u>Residential</u>										
Residential	562,089,257	(7,460,688)	554,628,569			1,165,584	2,866,864	558,661,017	19,508,443	578,169,459
Seasonal	7,837,281	(104,025)	7,733,255				39,973	7,773,228	1,522,775	9,296,004
Water Heating	1,171,461	(15,549)	1,155,912			2,429	5,975	1,164,316		1,164,316
	571,097,999	(7,580,263)	563,517,736			1,168,013	2,912,812	567,598,561	21,031,218	588,629,779
<u>General Service - Small</u>										
Non Demand	132,991,514	(1,765,215)	131,226,299			275,780	678,306	132,180,385	1,743,459	133,923,844
Seasonal	558,674	(7,415)	551,258				2,849	554,108	39,613	593,721
Water Heating	520,165	(6,904)	513,261			1,079	2,653	516,993		516,993
Total Non Demand	134,070,352	(1,779,534)	132,290,818			276,858	683,809	133,251,485	1,783,072	135,034,557
Demand	136,479,744	(1,811,514)	134,668,229			283,013	696,097	135,647,340	432,715	136,080,055
	136,479,744	(1,811,514)	134,668,229		-	283,013	696,097	135,647,340	432,715	136,080,055
<u>SEP</u>										
GSM	758,764		758,764			1,595	3,922	764,281		764,281
GSL	62,096		62,096					62,096		62,096
	820,860	-	820,860			1,595	3,922	826,377	-	826,377
<u>General Service - Medium</u>	187,901,858	(2,494,047)	185,407,811			389,645	958,369	186,755,825	41,086	186,796,911
	187,901,858	(2,494,047)	185,407,811			389,645	958,369	186,755,825	41,086	186,796,911

General Service - Large										
0 - 30 Kv	85,477,535	(1,134,555)	84,342,980			177,252	435,967	84,956,198		84,956,198
30 - 100 Kv	49,658,558	(659,125)	48,999,433					48,999,433		48,999,433
31 - 100 Kv Curtailable	8,926,647	(118,485)	8,808,163					8,808,163		8,808,163
Over - 100 Kv	112,728,207	(1,496,257)	111,231,950					111,231,950		111,231,950
Over - 100 Kv Curtailable	79,075,263	(1,049,577)	78,025,686					78,025,686		78,025,686
	335,866,210	(4,457,999)	331,408,211			177,252	435,967	332,021,430	-	332,021,430
Area & Roadway Lighting										
Street Lighting	18,594,032	(246,801)	18,347,231					18,347,231	244,223	18,591,454
Sentinel Lighting	3,056,945	(40,575)	3,016,370			6,339	15,592	3,038,301		3,038,301
	21,650,978	(287,376)	21,363,601		-	6,339	15,592	21,385,532	244,223	21,629,755
Diesel										
Residential	635,837	(8,440)	627,398					627,398		627,398
Full Cost	6,064,970	(80,501)	5,984,469					5,984,469		5,984,469
	6,700,808	(88,941)	6,611,867			-	-	6,611,867	-	6,611,867
Construction Power	-							-	-	-
Gen. Consumers Before Adj	1,394,588,808	(18,499,674)	1,376,089,133		-	2,302,715	5,706,567	1,384,098,416	23,532,315	1,407,630,730
Accrual - Other	2,333,691	(30,975)	2,302,715			(2,302,715)				
Miscellaneous - Non-Energy	634,731	(8,425)	626,306		(626,306)		-	-		
Late Pmt Charges & Cust Adj	5,783,330	(76,763)	5,706,567				(5,706,567)	-		
Total General Consumers	1,403,340,560	(18,615,838)	1,384,724,722	-	(626,306)	-	-	1,384,098,416	23,532,315	1,407,630,730
Extra-Provincial	344,484,000		344,484,000		749,306			345,233,306		345,233,306
Other (Non Energy net of Subs)	14,638,000		14,638,000	(14,515,000)	(123,000)			-		
Total Revenue	1,762,462,560	(18,615,838)	1,743,846,722	(14,515,000)	-	-	-	1,729,331,722	23,532,315	1,752,864,037

NOTES:
- Large Customers & Street Lighting Billed At Month End Therefore No ACCRUAL Allocated
- Export Surcharge To Extraprovincial Sales.

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2014

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:	
General Consumers Revenue	1,360.9
Additional GCR	47.6
Extra Provincial Revenue	344.5
Other Revenue (non-energy)	14.6
Total Revenue Per Financial Forecast	$ 1,767.6
Cost of Service Adjustments	
a. Transfer of Other Revenue (non-energy) to Operating	(14.5)
b. Uniform Rates Adjustment	23.5
c. BO 43/13 versus IFF12 Additional GCR	(5.1)
d. 1.5% of GCR accruing to deferral account per BO 43/13	(18.6)
Total Revenue Per Cost of Service Study	$ 1,752.9

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2014

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 2013 and 2014 adjusted for net regulated/intangible items and net major capital additions forecast to come into service during fiscal year 2013/14 which are included on an in-service date basis. This calculation is summarized below:

	2013	2014
Net Investment (Excluding Motor Vehicles)	$ 9,773.8	$ 10,460.9
Add: Total Net Regulated/Intangible Items	344.6	323.7
Less: Major Capital Item Additions 2014		(820.1)
	$ 10,118.4	$ 9,964.5
Average Investment (2013 + 2014) ÷ 2		$ 10,041.5
Add: Major Capital Item Additions 2014 on an in-service date basis		410.0
		$ 10,451.5

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SECTION D: LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2013/14 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. Due to a correction in the definition of peak hours, Load research data used to estimate this average seasonal class demand in PCOSS14 are based on the single year results for 2011/12. Load research data used to estimate non-coincident peaks are based on the eight year average of 2005/06 to 2011/12 data.

Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2013/14 the DSM savings are forecast to be 171 GW.h and 37 MW at generation, or 151 and 33 measured at the meter.

Schedule D1 outlines Manitoba Hydro's calculation of forecast demand for the 2013/14 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 2,225,595 MWh and 340.8 MW respectively have been taken from the 2012 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 PCOSS14 from the system peak forecasted in the 2012 Electric Load Forecast for the 2014 fiscal year. This difference of -72 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 1,355 customers was selected from Manitoba Hydro's various customer classes. All General Service Large 30 - 100 kV and >100 kV customers are metered.

Development of Class Loads

1. Residential Class

The 2013/14 forecast kWh sales to the Residential Class and the forecast number of customers are taken from the 2012 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 41 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 most recent 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 reduced by 58.1 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 8.5 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 2012 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 2012 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 45 GW.h and 11.4 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 162.5% is the same as used in previous studies.

The estimated coincident peaks at the meter have been reduced by 9.7 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 288 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 28.4 GW.h and 6.8 MW have been assigned to this class.

General Service Medium estimated coincident peaks at the meter have been reduced by 4.0 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-seven percent of the customers in the 0 - 30 kV subclass, 100% of the customers in the 30 - 100 kV subclass and 100% of the customers in the over 100 kV subclass are pulse metered.

The estimated coincident peaks at the meter have been adjusted by 0.0 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 37.0 GW.h and 6.0 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 2012 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 2012 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 2013/14 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 April 2012 actual billing data plus forecast additions to the system of 1,234 lights to year end 2014. 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 PCOSS14 includes 9,013 GWh in sales, which equals 9,834 GWh at Generation after adding back transmission losses of 821 GWh.

Only dependable export energy sales of 4,592 GWh or 5,010 GWh after allocation of losses are used to determine ‘Seasonal 2CP Demand’ in Schedule D1 and ‘Weighted Energy’ in Schedule D2 and as only dependable sales attract embedded generation and transmission costs.

2014 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	8,541,179,836	63.0%	5,380,943,297	70.1%	1,767,057	37.0%	3,160,236,539	73.0%	980,320	1,373,688
Seasonal	102,206,821	43.6%	44,603,685	162.5%	6,319	56.4%	57,603,136	162.5%	8,027	7,173
Water Heating	16,204,306	49.5%	8,021,131	126.0%	1,465	50.5%	8,183,175	126.0%	1,471	1,468
Total Residential	8,659,590,963		5,433,568,112		1,774,841		3,226,022,850		989,817	1,382,329
GS Small										
Non-Demand	1,854,567,658	57.8%	1,071,940,106	73.9%	333,915	42.2%	782,627,551	69.7%	254,269	294,092
Demand	2,363,968,908	56.1%	1,326,186,557	76.9%	396,998	43.9%	1,037,782,351	78.2%	300,518	348,758
Subtotal	4,218,536,565		2,398,126,663		730,913		1,820,409,902		554,787	642,850
Seasonal	5,707,215	20.0%	1,141,443	162.5%	162	80.0%	4,565,772	162.5%	636	399
Water Heating	5,558,687	49.7%	2,763,057	106.0%	600	50.3%	2,795,630	106.0%	597	599
Total GSS	4,229,802,467		2,402,031,163		731,675		1,827,771,304		556,020	643,848
General Service - Medium	3,653,690,359	53.0%	1,936,455,890	79.0%	564,275	47.0%	1,717,234,469	76.8%	506,337	535,306
General Service - Large										
0 - 30 Kv	1,942,588,302	50.6%	982,949,681	81.6%	277,301	49.4%	959,638,621	78.8%	275,773	276,537
30 - 100 Kv	1,226,541,957	52.2%	640,254,901	92.2%	159,857	47.8%	586,287,055	105.8%	125,486	142,672
30 - 100 Kv - Curtailed Cust	248,944,081	49.2%	122,480,488	102.3%	27,561	50.8%	126,463,593	95.9%	29,862	28,712
Over 100 Kv	3,111,483,050	52.7%	1,639,751,567	96.9%	389,551	47.3%	1,471,731,483	104.8%	318,008	353,780
Over 100 Kv - Curtailed Cust	2,259,539,507	50.1%	1,132,029,293	105.1%	247,951	49.9%	1,127,510,214	104.3%	244,798	246,374
Total G.S.- Large	8,789,096,897		4,517,465,930		1,102,221		4,271,630,966		993,927	1,048,074
Street Lighting	117,520,773	57.5%	67,618,144	86.7%	17,964	42.5%	49,902,629	0.0%	-	8,982
Total - General Consumers	25,449,701,458		14,357,139,240		4,190,977		11,092,562,218		3,046,102	3,618,539
Extra Provincial	5,010,288,250	37.6%	1,883,868,382	111.6%	388,594	62.4%	3,126,419,868	89.3%	792,806	590,700
Integrated System	30,459,989,708		16,241,007,622		4,579,571		14,218,982,086		3,838,907	4,209,239

2014 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				
	2013/14 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	8,521,043,223	Residential	271,360,282	529,183,839	340,424,463	530,833,673	971,255,256	501,744,893	355,928,175	647,461,792	409,306,731	970,331,612	1,781,479,342	1,211,733,164	8,521,043,223	27,844,416
Res FRWH	16,166,103	Residential FRWH	640,806	1,249,646	803,898	1,427,516	2,611,895	1,349,290	678,840	1,234,864	780,646	1,319,230	2,422,039	1,647,432	16,166,103	51,158
Res Seasonal	101,965,859	Residential Seasonal	4,298,847	8,383,246	5,392,950	10,149,077	18,569,553	9,592,925	4,009,417	7,293,450	4,610,709	7,262,579	13,333,724	9,069,382	101,965,859	319,181
GS Small Non Demand	1,850,195,345	GS Small Non-Demand	67,895,429	123,951,876	73,431,494	156,576,661	230,684,374	130,866,659	80,615,721	138,399,939	84,143,103	195,257,169	344,989,792	223,383,129	1,850,195,345	6,038,295
GSS FRWH	5,545,582	GS Small Non-Demand FRWH	236,556	431,863	255,844	558,619	823,014	466,894	245,779	421,951	256,534	472,661	835,120	540,746	5,545,582	17,762
GSS Seasonal	5,693,759	GS Small Non-Demand Season	315,740	576,424	341,485	917,673	1,352,008	766,991	176,643	303,258	184,372	194,116	342,974	222,078	5,693,759	17,349
GS Small Demand	2,358,395,635	GS Small Demand	85,921,826	155,366,756	96,100,641	188,308,568	304,345,775	181,420,512	103,989,806	180,745,346	113,495,193	239,173,298	426,063,812	283,464,103	2,358,395,635	7,613,687
GS Medium	3,645,076,450	GS Medium	141,405,988	251,798,208	154,762,674	320,012,836	515,001,767	312,147,269	158,729,513	273,323,182	169,859,303	347,078,363	605,705,190	395,252,155	3,645,076,450	11,687,150
GS Large <30KV	1,938,008,473	GS Large 750-30kV	79,618,476	136,040,218	88,796,887	177,973,309	279,794,081	183,744,548	85,125,671	141,286,166	94,163,949	175,949,776	295,581,342	199,934,048	1,938,008,473	6,150,735
GS Large 30-100kV	1,223,650,272	GS Large 30-100kV	42,383,367	83,881,916	64,707,994	88,978,341	168,044,467	130,499,588	47,072,282	90,735,622	71,116,283	98,309,203	189,778,980	148,142,228	1,223,650,272	3,750,152
GS Large 30-100kV Curtail	248,357,173	GS Large 30-100kV Curtailable	9,349,458	18,763,602	14,080,608	18,815,764	36,388,698	27,688,531	9,557,546	18,564,018	14,108,815	18,261,263	35,710,575	27,068,295	248,357,173	755,542
GS Large > 100kV	3,104,147,444	GS Large > 100kV	116,444,437	229,627,603	177,616,959	218,050,330	404,607,305	318,823,820	120,984,518	233,332,364	181,853,449	250,814,338	479,176,180	372,816,141	3,104,147,444	9,518,307
GS Large > 100kV Curtail	2,254,212,435	GS >100kV Curtailable	82,762,874	165,188,722	126,066,759	168,300,437	323,612,987	249,825,227	83,559,451	163,554,461	125,332,216	171,815,004	336,556,269	257,638,027	2,254,212,435	6,872,276
Streetlights	117,243,707	Street Lights	-	4,455,261	10,962,287	468,975	8,324,303	21,983,195	3,400,068	6,682,891	13,365,783	7,972,572	13,424,404	26,203,969	117,243,707	300,100
Total	25,389,701,458	Totals	902,634,085	1,708,899,181	1,153,744,944	1,881,371,779	3,265,415,483	2,070,920,341	1,054,073,430	1,903,339,304	1,282,577,085	2,484,211,184	4,525,399,744	3,157,114,897	25,389,701,458	80,936,108
Exports	5,010,288,250	Exports	214,892,366	394,273,751	214,162,497	533,651,385	1,000,120,297	634,300,041	209,648,525	399,109,735	254,530,786	313,318,899	570,134,666	272,145,303	5,010,288,250	15,381,070
		Weighting Factor	3.657	3.043	1.739	4.556	3.011	1.000	4.063	3.189	1.813	5.049	3.588	2.691		

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

			Spring			Summer			Fall			Winter				
Thermal Generation	2013/14 Forecast		Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	20,136,613	Residential	641,269	1,250,548	804,478	1,254,446	2,295,234	1,185,705	841,116	1,530,058	967,258	2,293,052	4,209,926	2,863,523	20,136,613	65,801
Res FRWH	38,203	Residential FRWH	1,514	2,953	1,900	3,373	6,172	3,189	1,604	2,918	1,845	3,118	5,724	3,893	38,203	121
Res Seasonal	240,962	Residential Seasonal	10,159	19,811	12,744	23,984	43,883	22,670	9,475	17,236	10,896	17,163	31,510	21,432	240,962	754
GS Small Non Demand	4,372,313	GS Small Non-Demand	160,448	292,918	173,531	370,016	545,145	309,259	190,508	327,062	198,844	461,424	815,267	527,891	4,372,313	14,269
GSS FRWH	13,105	GS Small Non-Demand FRWH	559	1,021	605	1,320	1,945	1,103	581	997	606	1,117	1,974	1,278	13,105	42
GSS Seasonal	13,455	GS Small Non-Demand Season	746	1,362	807	2,169	3,195	1,813	417	717	436	459	811	525	13,455	41
GS Small Demand	5,573,273	GS Small Demand	203,047	367,157	227,101	445,004	719,219	428,726	245,745	427,131	268,208	565,205	1,006,858	669,872	5,573,273	17,992
GS Medium	8,613,909	GS Medium	334,165	595,040	365,729	756,242	1,217,033	737,655	375,104	645,907	401,405	820,203	1,431,380	934,045	8,613,909	27,619
GS Large <30KV	4,579,830	GS Large 750-30kV	188,151	321,485	209,842	420,580	661,199	434,218	201,166	333,882	222,525	415,798	698,507	472,477	4,579,830	14,535
GS Large 30-100kV	2,891,685	GS Large 30-100kV	100,159	198,227	152,916	210,270	397,116	308,392	111,239	214,423	168,059	232,321	448,479	350,084	2,891,685	8,862
GS Large 30-100kV Curtail	586,908	GS Large 30-100kV Curtailable	22,094	44,341	33,275	44,465	85,992	65,433	22,586	43,870	33,341	43,154	84,390	63,967	586,908	1,785
GS Large > 100kV	7,335,606	GS Large > 100kV	275,177	542,647	419,738	515,288	956,153	753,433	285,906	551,402	429,749	592,715	1,132,371	881,025	7,335,606	22,493
GS Large > 100kV Curtail	5,327,071	GS >100kV Curtailable	195,582	390,368	297,916	397,721	764,750	590,378	197,465	386,506	296,180	406,027	795,337	608,841	5,327,071	16,240
Streetlights	277,066	Street Lights	-	10,529	25,906	1,108	19,672	51,950	8,035	15,793	31,586	18,840	31,724	61,924	277,066	709
Thermal Generation	60,000,000	Totals	2,133,071	4,038,407	2,726,487	4,445,988	7,716,709	4,893,922	2,490,947	4,497,901	3,030,939	5,870,596	10,694,257	7,460,777	60,000,000	191,265
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	3.657	3.043	1.739	4.556	3.011	1.000	4.063	3.189	1.813	5.049	3.588	2.691		

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, 2014

CALCULATION OF LOSSES

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	25,581,458,790
Common Bus Losses (After DSM)	2,225,595,902
Deliveries From Common Bus	23,355,862,888
Sales at Meter	22,380,760,707
Distribution Losses	975,102,181

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	4,316.28
Common Bus Losses (After DSM)	349.27
Deliveries From Common Bus	3,967.02
Calculated Distribution Losses	211.77
Calculated Demand at Meter (CP Load Factors)	3,834.65
Less: Adj made for curtailable load added back	-
Adjustment To Reconcile	(79.40)

MANITOBA HYDRO
2014 PROSPECTIVE COST OF SERVICE STUDY
March 31, 2014
DETERMINATION OF COINCIDENT PEAK DISTRIBUTION LOSSES

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	Losses	Energy @ Common Bus
RESIDENTIAL	7,404,453,323	501,750,184	7,906,203,506
G.S.S. SINGLE PHASE	1,360,752,741	92,209,095	1,452,961,836
G.S.S. THREE PHASE	2,292,472,846	116,373,484	2,408,846,330
* G.S.M.	3,199,161,713	162,400,002	3,361,561,715
* G.S.L. O - 30	1,704,481,206	71,184,758	1,775,665,964
G.S.L. 30 - 100	1,327,210,083	19,908,151	1,347,118,234
LIGHTING	100,487,088	6,809,337	107,296,425
MAN. HYDRO CONSTRUCTION	88,000,000	4,467,170	92,467,170
	17,477,019,000	975,102,181	18,452,121,181

* (includes SEP sales)

2) COINCIDENT PEAK AT COMMON BUS

C.P. AT GENERATION		4,316.28
LESS SALES AT CB LEVEL :		
	- EXPORTS	0.00
	- * G.S.L. >100	(593.42)
	C.B. LOSSES	(349.27)
	EXPORT LOSSES	0.00
COINCIDENT PEAK AT COMMON BUS		3,373.59

3) LOAD FACTOR AT COMMON BUS 62.4%
(Hours per Year = 8,760)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = $(0.08 \times 62.44\%) + (0.92 \times (62.44\%)^2)$
= 0.408614

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

a) $975{,}102 \times 0.1800 = 175{,}518$ MW.H

b) $\frac{975{,}102 \times 0.1800}{8{,}760} = 20.0$ MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{975{,}102. - 175{,}518}{8{,}760 \times (3{,}373.59)^2 \times 0.40861}$$
$$= 0.000020$$

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

$$= 20.04 + 0.00002 \text{ X } (3{,}373.59)^2$$
$$= 243.42$$

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 211.773 MW

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

AVERAGE (KW.h)	975,102	/ 17,477,019	= 5.58%
PEAK (MW)	211.77	/ 3,161.821	= 6.70%

Prospective Peak Load Report - Using Top 50 Peak Hours

2014 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	462,217	7,344,419,997	(41,215,066)	7,303,204,931	494,889,258	743,085,646	8,541,179,836
Seasonal	20,888	87,392,769	-	87,392,769	5,922,022	8,892,029	102,206,821
Water Heating	3,882	13,855,623	-	13,855,623	938,903	1,409,780	16,204,306
Total Residential	486,987	7,445,668,389	(41,215,066)	7,404,453,323	501,750,184	753,387,456	8,659,590,963
GS Small - Single Phase							
Non-Demand	41,074	970,700,754	(10,137,996)	960,562,758	65,090,901	97,735,228	1,123,388,887
Demand	4,221	395,919,368	(5,362,385)	390,556,983	26,465,430	39,738,347	456,760,760
Subtotal	45,295	1,366,620,122	(15,500,381)	1,351,119,741	91,556,331	137,473,574	1,580,149,646
Seasonal	859	4,880,000	-	4,880,000	330,685	496,530	5,707,215
Water Heating	380	4,753,000	-	4,753,000	322,079	483,608	5,558,687
Total Single Phase	46,534	1,376,253,122	(15,500,381)	1,360,752,741	92,209,095	138,453,712	1,591,415,548
GS Small - Three Phase							
Non-Demand	11,465	642,020,523	(6,705,261)	635,315,262	32,250,699	63,612,810	731,178,771
Demand	8,271	1,679,910,515	(22,752,931)	1,657,157,584	84,122,786	165,927,779	1,907,208,148
Total Three Phase	19,736	2,321,931,038	(29,458,192)	2,292,472,846	116,373,484	229,540,589	2,638,386,919
Total G.S.Small							
Non-Demand	52,539	1,612,721,277	(16,843,257)	1,595,878,020	97,341,600	161,348,038	1,854,567,658
Demand	12,492	2,075,829,883	(28,115,316)	2,047,714,567	110,588,215	205,666,126	2,363,968,908
Sub-Total G.S. Small	65,031	3,688,551,160	(44,958,573)	3,643,592,587	207,929,815	367,014,163	4,218,536,565
Seasonal	859	4,880,000	-	4,880,000	330,685	496,530	5,707,215
Water Heating	380	4,753,000	-	4,753,000	322,079	483,608	5,558,687
Total GS Small	66,270	3,698,184,160	(44,958,573)	3,653,225,587	208,582,579	367,994,301	4,229,802,467
General Service - Medium	1,974	3,203,094,420	(28,432,707)	3,174,661,713	161,156,301	317,872,345	3,653,690,359
General Service - Large							
0 - 30 Kv	288	1,716,337,934	(13,856,728)	1,702,481,206	71,101,231	169,005,865	1,942,588,302
30 - 100 kV	39	1,108,570,000	(5,286,871)	1,103,283,129	16,549,247	106,709,581	1,226,541,957
30 - 100 kV - Curtailment Cust's	1	225,000,000	(1,073,046)	223,926,954	3,358,904	21,658,223	248,944,081
Over 100 Kv	14	2,850,479,000	(9,696,069)	2,840,782,931	-	270,700,118	3,111,483,050
Over 100 Kv - Curtailment Cust's	2	2,070,000,000	(7,041,224)	2,062,958,776	-	196,580,731	2,259,539,507
Total G.S.- Large	344	7,970,386,934	(36,953,938)	7,933,432,996	91,009,383	764,654,518	8,789,096,897
SEP							
GSM	24	24,500,000		24,500,000	1,243,701	2,453,135	28,196,835
GSL 0 - 30 Kv	5	2,000,000		2,000,000	83,527	198,541	2,282,067
Total SEP	29	26,500,000	-	26,500,000	1,327,227	2,651,675	30,478,903
Street Lighting	129,050	88,794,199	-	88,794,199	6,016,988	9,034,622	103,845,809
Sentinel Lighting	25,974	11,692,889	-	11,692,889	792,349	1,189,727	13,674,964
Total - Lighting	155,024	100,487,088	-	100,487,088	6,809,337	10,224,349	117,520,773
Total - General Consumers	710,628	22,444,320,991	(151,560,284)	22,292,760,707	970,635,010	2,216,784,643	25,480,180,361
Extra Provincial		-	-	-		-	-
Man Hydro - Construction		88,000,000		88,000,000	4,467,170	8,811,259	101,278,429
Integrated System	710,628	22,532,320,991	(151,560,284)	22,380,760,707	975,102,181	2,225,595,902	25,581,458,790

2014 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	50.5%	1,660.2	(8.5)	1,651.7	80.9%	(64.3)	1,587.4	124.4	150.7	1,862.6	90.2%	1,759.9	2,064.9
Seasonal	157.8%	6.3		6.3		-	6.3	0.5	0.6	7.4	8.0%	79.0	92.7
Water Heating	67.9%	2.3		2.3		-	2.3	0.2	0.2	2.7	80.0%	2.9	3.4
Total Residential	50.9%	1,668.9	(8.5)	1,660.3	80.9%	(64.3)	1,596.1	125.1	151.5	1,872.7	86.7%	1,841.9	2,161.1
GS Small - Single Phase													
Non-Demand	62.0%	178.7	(2.7)	176.0	6.0%	(4.8)	171.2	13.4	16.3	200.9	86.3%	198.4	232.8
Demand	66.0%	68.5	(1.3)	67.2	0.7%	(0.5)	66.6	5.2	6.3	78.2	89.8%	74.2	87.0
Subtotal	63.1%	247.2	(4.0)	243.2	6.7%	(5.3)	237.9	18.6	22.6	279.1	87.3%	272.6	319.9
Seasonal	162.5%	0.3		0.3			0.3	0.0	0.0	0.4	8.0%	4.3	5.0
Water Heating	72.1%	0.8		0.8			0.8	0.1	0.1	0.9	75.0%	1.0	1.2
Total Single Phase	63.3%	248.3	(4.0)	244.3	6.7%	(5.3)	239.0	18.7	22.7	280.4	86.0%	277.9	326.1
GS Small - Three Phase													
Non-Demand	62.0%	118.2	(1.8)	116.4	4.0%	(3.2)	113.3	6.6	10.5	130.4	86.3%	131.2	151.1
Demand	66.0%	290.6	(5.6)	285.0	2.9%	(2.3)	282.7	16.4	26.3	325.4	89.8%	314.8	362.4
Total Three Phase	64.8%	408.8	(7.4)	401.4	6.9%	(5.4)	395.9	23.0	36.9	455.8	88.8%	446.0	513.4
Total G.S.Small													
Non-Demand	61.4%	296.9	(4.5)	292.4	10.0%	(7.9)	284.5	20.0	26.8	331.3	86.3%	329.7	383.9
Demand	65.1%	359.0	(6.9)	352.1	3.6%	(2.8)	349.3	21.6	32.7	403.6	89.8%	389.0	449.4
Sub-Total G.S. Small	64.2%	656.0	(11.4)	644.5	13.5%	(10.7)	633.8	41.6	59.5	734.9	88.2%	718.6	833.3
Seasonal	162.4%	0.3	-	0.3	0.0%	-	0.3	0.0	0.0	0.4	8.0%	4.3	5.0
Water Heating	72.1%	0.8	-	0.8	0.0%	-	0.8	0.1	0.1	0.9	75.0%	1.0	1.2
Total GS Small	64.2%	657.1	(11.4)	645.6	13.5%	(10.7)	634.9	41.7	59.6	736.1	87.7%	723.9	839.5
General Service - Medium	72.4%	505.0	(6.8)	498.3	5.5%	(4.4)	493.9	28.6	46.0	568.5	91.5%	539.8	621.3
General Service - Large													
0 - 30 Kv	79.6%	246.1	(2.7)	243.5	0.0%	-	243.5	11.5	22.4	277.4	89.3%	272.6	310.6
30 - 100 kV	91.0%	139.1	(1.0)	138.1		-	138.1	2.5	12.4	153.0	74.0%	186.6	206.7
30 - 100 kV - Curtailment Cust's	98.9%	26.0	(0.2)	25.8		-	25.8	0.5	2.3 †	28.6	93.6%	27.6	30.5
Over 100 Kv	91.0%	357.6	(1.3)	356.3		-	356.3	-	31.4	387.7	87.4%	407.7	443.6
Over 100 Kv - Curtailment Cust's	99.3%	238.0	(0.8)	237.1		-	237.1	-	20.9 †	258.0	81.2%	292.0	317.7
Total G.S.- Large	90.4%	1,006.7	(6.0)	1,000.8	0.0%	-	1,000.8	14.4	89.4	1,104.6	84.3%	1,186.5	1,309.1
SEP													
GSM	46.9%	6.0		6.0		-	6.0	0.3	0.6	6.9	81.0%	7.4	8.5
GSL 0 - 30 Kv	116.3%	0.2		0.2		-	0.2	0.0	0.0	0.2	14.3%	1.4	1.6
Total SEP	49.1%	6.2	-	6.2		-	6.2	0.4	0.6	7.1	70.5%	8.7	10.0
Street Lighting	119.7%	8.5	-	8.5		-	8.5	0.7	0.8	9.9	38.2%	22.2	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%	9.6	-	9.6	0.0%	-	9.6	0.8	0.9	11.2	38.2%	25.1	29.4
Total - General Consumers	66.5%	3,853.4	(32.7)	3,820.8	100.0%	(79.4)	3,741.4	211.0	348.0	4,300.3	86.5%	4,325.9	4,970.5
Extra Provincial	0.0%	0.0		0.0		-	-		-	0.0			
Man Hydro - Construction	72.4%	13.9		13.9		-	13.9	0.8	1.3	16.0			
Integrated System	66.5%	3,867.3	(32.7)	3,834.6	100.0%	(79.4)	3,755.2	211.8	349.3	4,316.3			

† Demand for curtailable customers is forecast as if customers are not curtailed at time of system peak.

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2014

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

	Class Avg
Export Sales	n/a
GS Large	
< 30	4.2%
30-100	1.5%
> 100	n/a
GS Medium	5.1%
GS Small	
3 Phase	5.1%
1 Phase	6.8%
Residential	6.8%
Area & Roadway Lighting	6.8%

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2014

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

	Class Avg
Export Sales	n/a
GS Large	
< 30	4.7%
30-100	1.8%
> 100	n/a
GS Medium	5.8%
GS Small	
3 Phase	5.8%
1 Phase	7.8%
Residential	7.8%
Area & Roadway Lighting	7.8%

SECTION E: ALLOCATION METHODS

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

- direct identification;
- the class's share of load (kW demand and 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 PCOSS14
- Schedules E2 – E19 represent some of the main tables used to allocate classified costs.

Prospective Cost Of Service Study
March 31, 2014
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Domestic & Export		312,674	177,604	362,322	5,766	858,365
E13	Generation - Domestic		2,286	9,610	24,929	-	36,825
			314,959	187,214	387,251	5,766	895,190
D13	Transmission - 2CP Domestic			-	2,375		2,375
D14	Transmission - 2CP Domestic & Export		72,419	65,280	71,499		209,198
			72,419	65,280	73,874	-	211,572
D21	Subtrans		2,106	20,004	22,838		44,948
D22	Subtrans	Stations	9,825	-			9,825
D23	Subtrans	Line	9,523	-			9,523
			21,455	20,004	22,838	-	64,296
D32	Dist. Plant Stn		21,797	26,313	36,101		84,211
D36	Dist. Plant	Lines	35,772	25,885	22,897		84,553
D40	Dist. Plant	S/E	11,280	11,974	4,125		27,378
			68,849	64,171	63,123	-	196,142
C23	Dist. Plant	Lines	23,848	17,256	15,265		56,369
C27	Dist. Plant	Services	3,155	2,283	2,019		7,456
C40	Dist. Plant	Meter Investment	1,702	4,197			5,899
C41	Dist. Plant	Meter Mtce.			2,188		2,188
			28,705	23,736	19,471	-	71,912
C10	Dist Serv	Cust Service - General	2,330	5,570	38,661	-	46,561
C11	Dist Serv	Cust Acct - Billings	1,455	2,607	24,147		28,210
C12	Dist Serv	Cust Acct - Collections	956	1,413	15,873		18,242
C13	Dist Serv	Marketing - R & D	42	53	690		784
C14	Dist Serv	Inspection	186	546	3,092		3,824
C15	Dist Serv	Meter Read	631	879	10,467		11,976
			5,600	11,068	92,929	-	109,597
	Total Allocated Costs		511,986	371,473	659,486	5,766	1,548,711

DIRECTS

C02	Generation	Diesel	991	1,566	6,804		9,361
E01	Generation	Export	23,532	13,312	105,884		142,728
			23,532	13,312	105,884	-	142,728
E01	Generation	SEP - GSM	183	116	171		470
E01	Generation	SEP - GSL 0-30kV	15	10	14		39
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	1,454	4,851	310		6,615
E01	Generation	GSS ND	1,041	3,953	67		5,060
E01	Generation	GSS Demand	1,099	4,294	84		5,477
E01	Generation	GSM	1,333	4,968	128		6,429
E01	Generation	GSL 0-30kV	742	2,630	68		3,439
E01	Generation	GSL 30-100kV excl Curt.	155	535	41		732
E01	Generation	GSL >100kV excl Curt.	418	1,293	105		1,815
E01	Generation	Street Lights	1	3	3		8
E01	Generation	Curtailment (GSL 30-100)	196	785	8	(604)	386
E01	Generation	Curtailment (GSL > 100)	1,813	7,128	75	(5,162)	3,854
			8,451	30,565	1,074	(5,766)	34,325
D04	Transmission	Export	-	-	1,696		1,696
D04	Transmission	SEP - GSM	42	38	42		122
D04	Transmission	SEP - GSL 0-30kV	4	3	3		10
			46	41	45	-	132
C01	Distribution	Lighting	3,547	3,926	7,850		15,324
C01	Distribution	Diesel	58	85	444		587
			3,606	4,011	8,294	-	15,911
	Total Directs		36,626	49,495	123,798	(5,766)	204,154
	Total		548,612	420,968	783,284	-	1,752,864
	Generation		347,933	232,658	501,013	-	1,081,604
	Transmission		72,465	65,321	75,616	-	213,401
	Subtransmission		21,455	20,004	22,838	-	64,296
	Distribution Plant		101,160	91,918	90,888	-	283,965
	Distribution Services		5,600	11,068	92,929	-	109,597
			548,612	420,968	783,284	-	1,752,864
	Energy		346,943	231,091	494,209	-	1,072,243
	Demand		162,768	149,495	161,576	-	473,840
	Customer		38,901	40,381	127,499	-	206,781
			548,612.04	420,968.00	783,284.00	-	1,752,864

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 2011/12.

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 load research data for 2011/12.

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 2011/12.

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.