

**NATIONAL ECONOMIC  
RESEARCH ASSOCIATES**

777 S. FIGUEROA STREET, SUITE 4200  
LOS ANGELES, CALIFORNIA 90017  
TEL: 213.346.3000 FAX: 213.346.3030  
INTERNET: <http://www.nera.com>



**Classification and Allocation Methods for Generation and  
Transmission in Cost-of-Service Studies**

**Prepared for**

**Manitoba Hydro**

**by**

**Hethie Parmesano**

**William Rankin**

**Amparo Nieto**

**Veronica Irastorza**

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# Table of Contents

I. INTRODUCTION AND PURPOSE OF REPORT .....	1
II. ROLE AND NATURE OF COS STUDIES .....	3
A. Steps in COS study .....	3
B. Choice of methods affects class revenue allocation and rate design .....	5
C. Typical “theoretical” considerations in choice of classification/allocation methods .....	6
D. Range of generation classification methods .....	6
E. Range of transmission classification methods .....	7
F. Time-differentiation and allocation methods.....	7
III. MANITOBA HYDRO CHARACTERISTICS THAT INFLUENCE CHOICE OF EMBEDDED COS METHODS.....	8
A. Generation resources and system planning.....	8
B. Exports and crediting of export revenues .....	9
C. Surplus Energy Program and Curtailable Rates.....	11
D. Ratemaking objectives .....	12
E. System Load and Customer Base .....	15
IV. CRITERIA FOR EVALUATING EMBEDDED COST STUDIES IN MANITOBA .....	17
V. FINDINGS FROM SURVEY OF SELECTED NORTH AMERICAN UTILITIES .....	19
A. Classification and Time-Differentiation .....	24
B. Allocation Methods.....	26
C. Treatment of Revenues from External (Off-System) Sales .....	27
VI. COS METHODS TESTED.....	28
VII. IMPLICATIONS FOR CLASS REVENUE ALLOCATION AND RATE STRUCTURE.....	30
A. Exports as a Class .....	30
B. Generation Classification, Time-Differentiation and Allocation Methods.....	33
C. Treatment of net export revenues .....	36
D. Transmission Classification and Time-Differentiation Methods.....	39
E. Effect of Combined Recommended Methods.....	40
F. Multiple Water Years.....	41
G. Implications for Rate Structure .....	42
H. Implications for Time-Differentiation of Rates .....	50
VIII. SUMMARY OF RECOMMENDATIONS .....	57



## I. INTRODUCTION AND PURPOSE OF REPORT

An Embedded Cost of Service (COS) study begins with a utility's total costs (operating expenses, debt service, return on equity, taxes, depreciation, etc.) for a particular test year and uses a series of steps to identify each customer class' share of various cost components. Because most of a utility's total cost depends on investment decisions made in the past, COS studies are typically designed to reflect the causes of those historical costs. COS studies are undertaken with the goal of creating an equitable allocation of historical total costs to various customer groups and individual customers without cross-subsidies.<sup>1</sup>

There are many alternative methods for conducting the various steps of a COS study. While there is no engineering or economic theory that determines which method is appropriate, methods are usually chosen based on the characteristics and objectives of the specific utility being studied.

Manitoba Hydro periodically prepares and submits to the Public Utilities Board of Manitoba (PUB) embedded cost studies to support its class revenue allocation and rate design. The PUB has established a policy of maintaining class cost allocations so that each class' ratio of revenue to allocated costs remains in a Zone of Reasonableness (ZOR) of 0.95 to 1.05, and gradually moving all class' ratios to unity.

In recent years Manitoba Hydro's COS methods have evolved to reflect changes in regional energy markets and the growing importance of revenues from export sales to prices charged to electricity consumers in Manitoba. The most recent changes, reflected in the March 27, 2002 update to the Prospective Cost of Service Study for 2002,<sup>2</sup> include:

- treating HVDC facilities (other than Dorsey Converter Station) as generation to reflect their role in moving energy from remote generators to the backbone transmission system;

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<sup>1</sup> The issue of cross-subsidy avoidance is complicated. A cross-subsidy exists when one class of customers pays a portion of the costs attributable to another class. But since different COS methods produce different estimates of class costs, there is no unambiguous measure of class cost-of-service. Furthermore, cross-subsidies can also be defined in terms of the marginal (rather than historical) costs of serving various customer classes.

<sup>2</sup> Manitoba Hydro Status Update Filing, Fall 2001. November 2001.

- functionalizing radial transmission as subtransmission, for consistency with the transmission tariff filed with the Mid-Continent Area Power Pool (MAPP);
- classifying transmission costs as 100% demand-related;
- classifying the generation costs according to a residual process: First the system load factor<sup>3</sup> is applied to combined generation plus transmission costs, to determine energy-related costs. The remaining amount is defined as demand-related. All transmission costs are then subtracted from the demand-related component. The classification of generation costs is determined by the residual amounts.
- allocating demand-related generation costs on the basis of each classes' share of system load in the average of the top 50 hours of winter load (December – February) and top 50 hours of summer load (June – August);
- allocating energy-related generation costs on the basis of class annual energy use, including losses.
- allocating transmission and ancillary services costs on the basis of contribution to 12 monthly coincident peaks, as in the Transmission Tariff.
- allocating the net revenues from export sales on the basis of generation, transmission and distribution costs allocated to each domestic class.<sup>4</sup>

In its February 2003 order, the PUB directed Manitoba Hydro to carry out a review of generation cost classification methodologies by December 31, 2003. The requested review would critically examine the impacts of the various methods of classifying generation costs and describe how such classification methods would impact the rate design process in terms of setting demand and energy charges.”<sup>5</sup>

This report summarizes the results of the review of generation classification methods requested by the PUB. Although the PUB’s order explicitly asks for analysis of generation

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<sup>3</sup> System load factor is the ratio of average hourly demand to peak hour demand on the system.

<sup>4</sup> The PUB did not accept all of these changes.

<sup>5</sup> Board Order 7/03, February 2003, p.100.

classification methods, the impact of alternative classification methods on class revenues and rate design depends also on the choice of customer classes, allocation methods, time-differentiation of costs, and allocation of net revenues from export sales. As a result, this report addresses aspects of those issues as well. Manitoba Hydro also asked us to make recommendations on treatment of transmission costs because the methods used for generation costs can also have implications for transmission costs, and because the PUB rejected the company's approach in the previous study.<sup>6</sup>

Working together, NERA and the Manitoba Hydro staff undertook the following tasks:

- Identify utilities to include in a survey of embedded cost methods
- Identify tentative methods for study
- Conduct the survey<sup>7</sup>
- Develop criteria for evaluating methods
- Identify pros and cons of possible methods
- Quantify the impacts of promising methods on class revenue allocation and rate structure
- Develop recommendations

## **II. ROLE AND NATURE OF COS STUDIES**

### **A. Steps in COS study**

COS studies follow three steps: functionalization, classification and allocation. In some cases another step – time-differentiation – is added or incorporated in one of the other steps. Some studies also geographically differentiate certain cost elements.

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<sup>6</sup> The PUB rejected the use of a 12-CP allocator for transmission costs and ordered use of a 2-CP approach, using the 50 highest load hours in summer and 50 highest load hours in winter as the hours of interest. (Feb. 3, 2003 Order, p. 101)

<sup>7</sup> Detailed results were reported in a separate document – “Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America,” December 22, 2003.

The first step is to *functionalize* total costs into categories such as generation, transmission, distribution and ancillary services. While in general power plants are classified as generation and transmission lines as transmission, sometimes these facilities perform other functions. A power plant can be functionalized as transmission if it provides ancillary services. Step-up transformers and switching facilities at generators as well as radial lines connecting remote generators to the grid (e.g., “coal by wire”) are often functionalized to generation. Interties built primarily to export and/or import energy are also sometimes functionalized to generation. In Manitoba Hydro’s case, most HVDC facilities are functionalized as generation since they move low-cost energy from remote generating stations into the backbone transmission system.

Functionalized costs are then *classified* as demand-, energy- or customer-related based on some notion of cost causation. Demand-related costs are those triggered by peak demands imposed on the system. Energy-related costs are related to the level of energy production. Customer costs vary according to the number and type of customers.

The third step is *allocation* of functionalized and classified costs to customer classes. Energy-related costs are allocated according to a measure of each class’ energy usage (kWh), demand-related costs are allocated according to some measure of demand (kW) and customer-related costs are allocated according to the number of customers in each class, weighted or unweighted, depending on the nature of the cost.

Some utilities *time-differentiate* embedded costs by time of day or season. A time-differentiated COS study typically develops energy-related and demand-related generation costs by several costing periods and then uses energy usage and peak demand measures within those periods in the allocation step.

Costs can also be *geographically-differentiated* to various territories or zones. Utilities with operations in more than one state (or with wholesale rates regulated by FERC) have to allocate costs by jurisdiction. This extra step can be important if costs vary considerably across the state and a goal of rates is to reflect those differences.<sup>8</sup>

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<sup>8</sup> Manitoba Hydro has traditionally had rates that varied by 3 zones characterized by customer density. With the introduction of uniform rates in 2001 Manitoba Hydro’s rate zone distinctions were eliminated and Zone 2 and 3 rates were reduced to be the same as the rate charged in Zone 1.



## **B. Choice of methods affects class revenue allocation and rate design**

The classification and allocation methods used in a COS study are key factors in determining final rates in jurisdictions in which embedded costs are used to set class revenue requirements. In some jurisdictions the goal is to have all customer classes provide the same (or nearly the same) rate of return on allocated investment. In others, including Manitoba, the goal is to maintain the same (or nearly the same) ratio of revenue to allocated costs for all classes.

While most methods allocate energy-related costs according to each class' energy consumption (sometimes by costing period), the main differences lie in the approaches used to classify and allocate demand-related costs. Since generation costs are usually the largest functional cost component, revenue allocations are particularly sensitive to the methods used for classifying and allocating generation costs.

Methods that classify a higher share of the costs as demand-related tend to assign less revenue to large commercial and industrial classes, which have high load factors, and more revenue to residential and small commercial customer classes, which have lower load factors. Allocation methods that focus on class demands in just a few hours of the year also tend to favor large commercial and industrial classes over residential and small commercial classes.

Choice of classification and allocation methods also affects rate design for each class. Methods that result in high demand-related costs typically call for high demand charges relative to energy charges. Such rate designs favor higher load factor customers within the class.

The treatment of revenues from export sales within the COS study also has an impact on both class revenue requirements and rate design, particularly when these revenues are large relative to revenues from domestic customers, which is the case in Manitoba. For example, crediting export revenues to classes on the basis of allocated generation and transmission costs (the PUB's current method) favors large customers and disadvantages smaller customers for whom distribution costs are a significant share of their allocated costs. This approach can result in residual generation cost allocations for large customers that are well below marginal cost.

### **C. Typical “theoretical” considerations in choice of classification/allocation methods**

There is no universally accepted method for classifying and allocating embedded costs. There is also no specific economic or engineering theory to guide the choice of allocation and classification methods. As a result, these decisions are usually based on judgments and depend mostly on the objectives of the cost analyst and the characteristics of the particular company being analyzed.

Factors that often affect choice of methods include (1) the type of generation plant the utility has; (2) planning and operating constraints/policies; (3) the pattern of system loads across the year, including whether the system is winter-peaking, summer-peaking, or both; (4) the system load factor; (5) the importance of purchases from and sales to outside entities; and (6) the degree to which decision-makers want to reflect marginal cost or opportunity cost relationships in the COS study.

### **D. Range of generation classification methods**

The variable costs associated with operating generation plants (fuel, water charges, certain non-fuel operating and maintenance expenses) are clearly a function of energy produced. These costs are nearly always classified as energy-related.<sup>9</sup>

The fixed costs of generation—depreciation, interest expense, return on equity (or equivalent for publicly-owned utilities), property and other taxes, property insurance, etc.—are more difficult to classify. While the utility must install (or purchase) sufficient capacity to meet its peak load obligations plus a reserve margin, the choice of resources to make up that capacity depends on the number of hours each resource is expected to run—i.e., how much energy it will produce. It is cost-effective to acquire resources with high fixed costs and low operating costs if the unit will run for many hours of the year, whereas a resource expected to be needed only a few hours of the year would generally have lower fixed costs and higher operating costs.

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<sup>9</sup> Where these costs are very small relative to total generation costs and where the generation costs are not all classified as demand-related, the variable plus fixed generation costs are sometimes classified together. This is the approach that has traditionally been used by Manitoba Hydro.

Although the method that classifies all generation fixed costs as demand-related is sometimes used, most methods recognize that a portion of fixed costs are associated with the need for energy and classify some fixed costs as energy-related. These methods include:

- the system load factor approach—which treats the portion of generation costs equal to the system load factor as energy-related and the remainder as demand-related;
- the capital substitution approach—which identifies for each resource the equivalent fixed cost of a peaking unit, treats this amount as demand-related and the remainder as energy-related;
- the peak and average approach—which classifies fixed costs into demand and energy portions using an arbitrary split, such as 50-50;
- the marginal cost or opportunity cost approach—which classifies fixed plus variable generation costs in proportion to the time-differentiated marginal cost of capacity (often represented by the cost of a peaking unit) and energy, and usually taking into account market prices in the region
- the specific plant approach—which uses different classification methods for each type of plant (e.g., system load factor for hydro plants, 100% demand-related for peaking units).

### **E. Range of transmission classification methods**

Costs functionalized to transmission are typically classified as entirely demand-related. However, lines whose primary function is to facilitate energy exports and/or imports are sometimes classified as energy-related. Other methods that classify a portion of transmission costs as energy-related are also possible.

### **F. Time-differentiation and allocation methods**

There is also a range of methods for time-differentiating demand- and energy-related generation costs. These methods all involve somewhat arbitrary splits based on the type of resource (baseload, intermediate or peaking), the hours when particular units typically run, or

(for time-differentiating demand-related costs) the probability of loss-of-load in given pre-set costing periods. The marginal cost/opportunity cost classification method uses the seasonal/diurnal relationships in marginal costs for time-differentiation of both generation capacity and energy costs.

Allocation methods for demand-related costs use some measure of class contribution to peak demands, ranging from contribution to the single annual system peak, to contribution to system peaks in a much larger number of high load hours, to the relationship between class load factor and system load factor. Allocation methods for energy-related costs use class share of energy production—either on an annual basis or by costing period.

### **III. MANITOBA HYDRO CHARACTERISTICS THAT INFLUENCE CHOICE OF EMBEDDED COS METHODS**

Choosing appropriate COS methods for Manitoba Hydro involves taking into consideration the utility's unique resources, as well as its operating and marketing practices, public policy objectives, and customer characteristics.

#### **A. Generation resources and system planning**

Nearly all of Hydro's electricity is generated from waterpower. On average, 30 billion kWh are generated annually, with 98% produced from 14 hydroelectric generating stations on the Nelson, Winnipeg, Saskatchewan and Laurie rivers. About two percent of the province's energy needs are produced from three thermal generating stations and four remote diesel stations.

The total capacity of the existing hydro plants is 4,828 MW and the 3 thermal plants have a total capacity of 535 MW. Additionally, Manitoba Hydro has signed seasonal diversity agreements with several US utilities that experience peak loads in the summer months and therefore can provide power to Manitoba during winter.<sup>10</sup>

Manitoba Hydro is a member of MAPP, which means that the utility must maintain every month sufficient accredited capacity to cover its monthly firm peak load plus 10% of its

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<sup>10</sup> Agreements covering a total of 500 MW are in place until 2016, with the amounts decreasing afterwards until they reach zero by 2019. *Submission to the Manitoba Clean Air Commission: Need for and Alternatives to the Wuskwatim Project*, April 2003.

annual firm peak load. Given its hydro resources, Manitoba Hydro's internal capacity planning requirement – to have sufficient planned generation capacity to cover forecast annual firm peak demand plus a reserve requirement of 12% of forecast firm loads — is the binding constraint. In addition, Manitoba Hydro uses an energy planning criterion to ensure that there are sufficient dependable resources to cover forecast firm energy requirements.<sup>11</sup>

Manitoba Hydro's huge investment in hydro facilities adds a number of complexities to the choice of COS methods:

- clearly not all of the fixed costs of such facilities are demand-related, as they provide energy at a very low cost compared to thermal units or energy purchases;
- Manitoba Hydro's large water storage capability allows the utility to respond to daily and seasonal variations in load by managing the timing of water release;
- the energy capability of hydro facilities is significantly reduced in very cold weather due to icing;
- the variability of water conditions from year to year affects the amount of energy that can be counted on—Manitoba Hydro's energy requirements are the driving force behind most generation investment and power contracting decisions; once the energy requirements are met, capacity is not a problem.

## **B. Exports and crediting of export revenues**

Manitoba Hydro sells firm and short-term opportunity products into Midwestern US states area and, to a lesser extent, to neighboring provinces. Export sales depend upon the quantity of generation surplus to domestic load, the availability of interconnection capability and the size of the export market. Manitoba Hydro is able to make significant firm export sales because its hydro plants come into service in large blocks, and it is economic to complete all the units earlier than required for domestic load. Opportunity (non-firm) sales arise from the variability in stream flow at hydro plants. Since the system is designed based on the lowest flow, in most years there is a surplus of hydro energy available for export.

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<sup>11</sup> Manitoba Hydro Status Update Filing, November 30, 2001, pp. 71-72.

In normal years, Manitoba Hydro exports over 30% of its hydro production. Prices for export sales have increased substantially over time. The annual average export price for FY 02/03 was CN\$47.70 per MW.h and is forecast to be CN\$52.2 per MW.h in FY 03/04.<sup>12</sup>

Manitoba Hydro's net export revenues grew from 17% of total revenues in 1993 to 43% of total revenues in FY 01/02.<sup>13</sup> In FY 02/03, export sales reached CN\$463 million (or 34% of total sales) in spite of low hydro conditions.<sup>14</sup> For FY 03/04, net export revenues are forecast to fall to CN\$390. This reduction is due to a 23% decrease in the volume of exports, a substantial increase in imports needed to support exports (from 3,043 GWh in FY 02/03 to 8,000 GWh in FY 03/04), and a higher average fuel cost associated with exports (from CN\$36.6/MWh to CN\$44.8/MWh).

In addition to selling surplus energy from existing facilities, Manitoba Hydro has opportunities to accelerate the construction of planned hydro facilities and sell the additional energy in the export market. For example, the utility has proposed to place the Wuskwatim Generation Station in service in 2010, earlier than originally planned. The additional capacity would translate into more surplus energy to market between 2010 and 2020. Manitoba Hydro expects to sell this energy at on-peak prices under the majority of water flow conditions.<sup>15</sup>

As the statistics above indicate, Manitoba Hydro's export sales are, in normal years, a very large share of total energy production and total revenues. Export sales are an important factor in keeping rates to domestic customers low. These sales also significantly affect the utility's generation system planning and operation. Export sales change the pace of new generating plant additions, the pattern of loadings on Manitoba Hydro's transmission system and the operation of its generating units. Furthermore, firm export sales can require Manitoba Hydro to purchase energy to fulfill its obligations to export customers in years when water supplies are low. Export sales from hydro resources trigger additional water rental costs. As a

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<sup>12</sup> Manitoba Hydro 2003 Annual Report & Manitoba Hydro's 2003 generation forecast.

<sup>13</sup> The number of its US customers also jumped, from 5 in 1993 to 50 in 2002. (Source: Public Utilities Board, Board Order 7/03, February 2003, p.21 and 44.)

<sup>14</sup> Manitoba Hydro Electric Board, 52nd Annual Report For the Year Ended March, 2003, p. 25.

<sup>15</sup> Manitoba Hydro, Submission to the Manitoba Clean Environment Commission: Need for and Alternatives to the Wuskwatim Project ch5 p 25.

result, export sales must be taken into account in selecting COS methods appropriate for Manitoba Hydro.

Manitoba Hydro historically has not treated export customers as a class. Rather, export revenues (net of variable costs attributable to exported energy) have been credited back to domestic classes. In the past these credits were allocated on the basis of total allocated generation and transmission costs. In its most recent submission to the PUB, the utility proposed to allocate the net revenues on the basis of allocated generation, transmission and distribution costs, giving a larger share of the credits to classes served at distribution voltage than under the previous method. The PUB rejected this proposed approach.<sup>16</sup> The PUB also asked Manitoba Hydro to study the creation of an export class or classes and alternative ways to identify export costs and to allocate net export revenues.<sup>17</sup>

The price of export sales represents, in many hours of the year, Manitoba Hydro's opportunity cost of supplying marginal energy and capacity to its domestic customers. When a domestic customer uses an additional kWh in these hours, there is one less kWh to sell to the export market and the profits on that lost sale are not available to keep rates low to domestic customers. Thus, consumption decisions by a domestic customer have an important effect on the rates charged to other domestic customers. While this situation is not unique to Manitoba Hydro (many utilities charge less for marginal purchases by their retail customers than the marginal cost of supplying that energy), the effect is particularly strong in Manitoba because of the size of the export profits relative to total utility costs.

### **C. Surplus Energy Program and Curtailable Rates**

The design of Manitoba Hydro's Surplus Energy Program (SEP) and Curtailable Rates reveal the importance of market prices to the utility's operations. The SEP permits eligible customers<sup>18</sup> to purchase surplus hydro energy at rates comparable to export prices. The SEP energy charges for peak, shoulder and off-peak hours are computed on a weekly basis based on a forecast of expected regional spot prices, and are submitted to the PUB for interim approval.

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<sup>16</sup> Order 7/03, February 2003, p. 97.

<sup>17</sup> Order 154/03, October 31, 2003, pp. 31-33.

Manitoba Hydro's new suite of Curtailable Rates offers per-kW credits that vary with the limitations on curtailments.<sup>19</sup> Curtailments can be called to maintain reliability and operating reserves, to make firm export sales, and to compensate for forecast errors or loss of a facility. The reference credit is a reasonable judgment that balances the value necessary to attract curtailable load with the long-term value of curtailment. This approach avoids revealing Manitoba Hydro's commercially-sensitive estimates of the market value of capacity.

#### **D. Ratemaking objectives**

In its last major rate change submission to the PUB, Manitoba Hydro identified five specific ratemaking objectives and six longer term directions.<sup>20</sup> The specific ratemaking objectives are:

1. To achieve Manitoba Hydro's full Revenue Requirement for General Consumers.
2. To collect revenue from each customer class that bears a reasonable relationship to cost allocated to serve that class, using PUB approved cost-of-service study methods.
3. To put in place rate structures and accompanying processes of applications, billing, metering and service extension which assure equitable treatment of customers both within and between classes.
4. To promote efficient use of power and energy.
5. To have the practical attributes of:
  - stability and continuity of rates (gradualism of change)
  - minimum of unexpected adverse change
  - enhancing revenue stability and predictability

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<sup>18</sup> Commercial/industrial customers whose connected load exceeds 200 kilowatts (kW) and who meet other eligibility requirements.

<sup>19</sup> This program is available to industrial customers whose connected load exceeds 5,000 kilowatts (kW) and who meet other eligibility requirements. The specific credit varies with the curtailment option selected by the customer.

<sup>20</sup> Manitoba Hydro's November, 1995 General Rate Application, pp. 81-103.



- freedom from controversy as to proper application
- feasibility of application
- public acceptability
- simplicity and understandability.

Six longer-term directions cited by Manitoba Hydro are (paraphrased):

1. Improve Inter-Class Equity – by gradually moving all classes to a revenue/cost ratio of unity, with class revenue allocation changes up to two percent greater than the average overall rate increase.
2. Limit bill impacts (for unchanged consumption) on individual customers – to the higher of \$3 per month or 3 percentage points about the average class increase for residential customers; and to the higher of \$5 per month or 5 percentage points above the class average increase for general service customers.
3. In recognition of the importance of efficient price signals, incorporate explicit consideration of incremental costs in design of both regular firm rates and any special rate options such as DFH/ISE [Dual Fuel Heating and Industrial Surplus Energy – both of which have been replaced by the Surplus Energy Program].
4. Adjust seasonality of prices to better reflect incremental cost patterns.
5. Simplify rate schedules to improve understandability and reduce the number and complexity of rate schedules, within the constraints of other rate design objectives.
6. Continue to refine alternative rates for large industrial customers that meet the requirements of these customers while assuring reasonable cost recovery for Manitoba Hydro.

Manitoba Hydro's filing in the last rate case also specifically mentioned the long-term goal of adjusting rates to reflect competitive markets.

For many years the PUB has had a policy of promoting cost-based rates. Recent Orders have included statements indicating that the PUB believes that incremental costs and market conditions should be factors in the setting of efficient, cost-based rates:

- The PUB supported continued use of the 2 CP method for allocating demand-related generation costs because, although domestic load peaks in the winter, export sales in the summer can result in capacity being fully utilized in that season as well.<sup>21</sup>
- The PUB ordered a study of inverted rates, under which higher prices for the tail block of the energy charge could give more efficient price signals to encourage conservation.<sup>22</sup>
- The PUB also ordered a study on the impact of decreasing demand charges and increasing energy charges, as an impetus to further conservation of electricity.<sup>23</sup>
- The PUB ordered a study of time-of-use rates for general service classes, which would also improve the efficiency of price signals.<sup>24</sup>
- The PUB has ordered Manitoba Hydro to phase out the winter demand ratchet, which was justified by winter peak demands, because the current system runs at nearly full capacity year-round due to export sales.<sup>25</sup>
- Citing the financial benefits that additional conservation by domestic customers provides by permitting greater export sales, the PUB asked Manitoba Hydro to re-examine the current level of DSM programs and pricing strategies to encourage conservation.<sup>26</sup>
- The PUB has recognized Manitoba Hydro's concern that allocation of large amounts of export revenues as credits to domestic classes on the basis of only

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<sup>21</sup> Order 7/03, p. 101.

<sup>22</sup> Order 7/03, pp. 104-105.

<sup>23</sup> Order 7/03, pp. 104-105.

<sup>24</sup> Order 7/03, p.106.

<sup>25</sup> Order 7/03, p. 105.

<sup>26</sup> Order 7/03, p. 107.

allocated generation and transmission costs can result in energy charges that fall below short-run marginal cost.<sup>27</sup>

- In prescribing the form of the rate reductions in the most recent rate case, the PUB accepted Manitoba Hydro's proposal to make reductions in demand charges and the first blocks of energy charges,<sup>28</sup> an approach that Manitoba Hydro pointed out would minimize the adverse impact on conservation efforts.<sup>29</sup>

Several of the company's stated objectives and PUB policies have implications for determining appropriate COS methods for Manitoba Hydro:

- Price signals that encourage efficient energy and power consumption decisions, explicit incorporation of incremental costs in standard and special rate design, and reflection of seasonal cost patterns suggest that the COS methods should incorporate marginal or incremental cost elements.
- Taking competitive market conditions into account requires that the COS methods incorporate market price relationships.
- The combined efficiency and equity objectives suggest that the treatment of Manitoba Hydro's large and variable export revenues is a critical element of the COS study.

## **E. System Load and Customer Base**

Manitoba Hydro's 2003 peak demand (set on February 24) was 3916 MW, breaking the previous record of 3760 MW (set on January 29, 2002). Industrial electricity use in this sector is expected to grow at an average of 1.7% annually over the next 10 years.<sup>30</sup> Manitoba Hydro has projected an 18% increase in energy use and a 13% increase in demand by its domestic customers over the next 10 years.<sup>31</sup> The following table shows a breakdown of Manitoba

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<sup>27</sup> Order 154/03, pp. 31-32.

<sup>28</sup> Order 1/04, p. 5.

<sup>29</sup> Manitoba Hydro, Application for New General Service Rates Effective April 1, 2003 Flowing from Board Order 154/03, pp. 5-6.

<sup>30</sup> Manitoba Hydro Electric Board, 52nd Annual Report For the Year Ended March, 2003, p.73

<sup>31</sup> The Public Utilities Board, Board Order 7/03, February 2003, p35.

Hydro's electricity sales in the last three years. Manitoba Hydro supplied Winnipeg Hydro on a wholesale basis until its acquisition on September 3, 2002, and directly supplied the retail customers thereafter. The table highlights the importance of export sales.

**Energy Sold (GWh)**<sup>32</sup>

	<b>2003</b>	<b>2002</b>	<b>2001</b>
Residential	6,135	5,206	5,282
General Service Small	3,030	2,515	2,523
General Service Medium	2,488	1,802	1,740
General Service Large	6,541	5,873	5,608
Area & Roadway Lighting	83	68	68
Winnipeg Hydro Wholesale	629	1,452	1,431
Direct Customers	46	42	46
<b>Total Manitoba Sales</b>	<b>18,953</b>	<b>16,958</b>	<b>16,698</b>
Extraprovincial sales	9,735	12,298	12,154
<b>Total Sales</b>	<b>28,688</b>	<b>29,256</b>	<b>28,852</b>

As the table below indicates, Manitoba Hydro's customer mix is dominated by residential and small general service customers, although the small number of large general service customers accounts for a large amount of domestic energy sold.

<sup>32</sup> Sources: 52<sup>nd</sup> Annual Report Operating Statistics, p. 95, and data received from the Manitoba Hydro Customer Rates and Policies Department (M. Dust, January 29, 2004).

**Number of Customers in 2003<sup>33</sup>**

	<b>Customers</b>
Residential	439,757
Small	59,444
Medium	1,750
Large	276
Area & Roadway Lighting	748
<b>Total</b>	<b>501,975</b>

#### **IV. CRITERIA FOR EVALUATING EMBEDDED COST STUDIES IN MANITOBA**

General COS methods that are suitable for use in Manitoba must meet the following criteria:

- **Consistency with ratemaking objectives** - The methods must be consistent with Manitoba Hydro's general ratemaking-objectives. As suggested in the previous section, this means that the methods must incorporate marginal cost elements and market prices, and provide an efficient and equitable treatment of export revenues. These criteria are elaborated below.
- **Consistency with Manitoba Hydro's predominantly hydro resource** - COS methods that are valid in a hydro/thermal system may not reflect cost-causation in an almost purely hydro system.
- **Consistency with Manitoba Hydro's system load pattern** - The time-differentiation of generation and transmission costs and the allocation methods chosen should take into consideration Manitoba Hydro's system load shape. Factors such as weather variations and the particular customer mix influence the system load shape, which in turn affects decisions on time-differentiation and allocation of costs.
- **Consistency with importance of export sales to Manitoba Hydro's operations and revenues** - Export sales have a strong impact on the utility's operation and planning. The COS methods adopted should recognize this, and permit creation of an export class. In addition, the size of export revenues may

<sup>33</sup> Source: 52<sup>nd</sup> Annual Report and data received from Manitoba Hydro Rates and Policies Department.

have implications for time-differentiation and classification. Finally, if exports are treated as a separate class, the relevant load shape is that of the utility's combined domestic and export loads.

- **Consistency with marginal cost principles** - Manitoba Hydro and its regulator believe in reflecting marginal cost or opportunity cost relationships in the COS study, in order to achieve efficiency goals as much as possible. COS methods that classify and time-differentiate costs on the basis of underlying marginal cost relationships—seasonal, time-of-day and energy v. demand—are more likely to result in class revenue allocations and rate structures that send more efficient price signals than methods that ignore these relationships.
- **Implications for cost shifts among classes** - A factor in evaluation of COS methods is the implied change in cost allocations among classes. Although it is certainly possible to combine adoption of new methods that cause significant cost shifts with a transition plan that gradually phases the cost shifts into rates, it is important to know the cost shifting implications of any methods chosen.
- **Implications for changes in rate structure** - Classification and time-differentiation methods also have implications for rate structure. If the COS results are applied directly to rate design, the resulting rates may be quite different from current rates in terms of the mix of fixed and variable charges, the relative size of energy and demand charges, and the patterns of seasonal and time-of-day charges. These changes create differential bill impacts within the class. As is the case for class revenue implications, a transition plan can be used to temper bill impacts of rate structure changes, although it is important to be aware of the need for such a plan before settling on new COS methods.
- **Understandability and Acceptability** - COS methods adopted by Manitoba Hydro should be sufficiently transparent and understandable, and produce an outcome acceptable to the PUB, intervenors and customers in general. There are often differences in the goals of the parties involved in or affected by the results of the COS study. Regulatory, utility and customer concerns must be taken into account to achieve acceptability of the proposed method. A key element of

acceptability is the perception that the COS study is based on reasonable assumptions and is replicable. This means that data relied upon for classification and allocation can be supplied to stakeholders without compromising information that is commercially sensitive to Manitoba Hydro (such as detailed market price forecasts and export sales volumes).

- **Ease of implementation** - COS methods chosen for use in Manitoba must be implementable. Information necessary to create the classification, time-differentiation and allocation factors must be available. Furthermore, additional investment in billing and metering systems may be required to implement rates based on the new COS studies.
- **Long-term applicability** - The methods chosen should be expected to fit Manitoba Hydro's situation for many years into the future. If customers were gradually permitted to shop for new suppliers of energy and capacity, would major revenue shifts be necessary to recover otherwise stranded costs? Methods that do not reflect long-term market conditions are more likely to outlive their usefulness as the regional market evolves.

## V. FINDINGS FROM SURVEY OF SELECTED NORTH AMERICAN UTILITIES

A survey<sup>34</sup> of generation and transmission classification and allocation methods currently or formerly used by ten selected North American utilities with at least some characteristics similar to Manitoba Hydro's<sup>35</sup> revealed a range of methods. The table below summarizes the results.

In recent years there has been a major shift away from traditional methods used in an era before the development of vibrant wholesale markets (e.g., fixed/variable classification; no time-differentiation; allocation based on class loads in a very few hours of the year) to methods

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<sup>34</sup> "Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America". NERA. December 22, 2003.

<sup>35</sup> (1) Substantial hydroelectric capacity, relative to other generation sources; (2) active participation in a competitive wholesale market, and/or (3) substantial off-system/export sales.

that better reflect regional market conditions and the pattern of the utility's marginal or opportunity costs.



	<b>BC Hydro</b>	<b>Bonneville Power Administration</b>	<b>Hydro Quebec</b>	<b>Idaho Power</b>
<b>% of Hydro Capacity &amp; Off-System Sales</b>	Over 87% of capacity is hydro. 30% of total sales in FY2001 were off-system	67% of firm energy comes from hydro. 79% of FY 2001 sales were off-system	97% of capacity is hydro In 2001, off-system sales represented 15% of total sales	58% of capacity is hydro 15.5% of total sales were for resale in FY 2001.
<b>Latest Emb. COS</b>	1998	2002	2001	2003
<b>Classification Method</b>	Specific Facilities Approach: - Hydro: Cap Sub method. - Thermal: 100% demand.  Purchase costs: 100% energy-related costs. Water rental fees: 84.7% energy, 15.3% demand (reflecting variable and fixed components)  Transmission: 100% demand; (generation-related transmission is functionalized to transmission)	Based on marginal costs.  The delta above average market price is used to approximate marginal demand costs.  Load variance costs are estimated using an option price.  Energy costs are the residual revenue req. after deducting demand and load variance costs.  Transmission: 100% demand	Load factor method  Transmission (incl. transformers & transformation substations): 100% demand.	System load factor for own generation fixed costs.  Purchase costs: 100% energy-related.  Transmission: 100% demand
<b>Time-Differentiation?</b>	No	12 seasons for energy and demand.	No	Two seasons (summer and non-summer) based on marginal cost relationships. No daily-time differentiation.
<b>Allocation Method</b>	<u>Demand-related</u> : Average of 12 CP <u>Energy-related</u> : class kWh share	Allocation of generation costs among classes of service is based on priorities set by federal legislation, with a cost-benefit test used as a final check on reasonableness.  Transmission allocated based on annual contracted demand and monthly CP.	Allocation of generation demand costs based on the relationship between class load factors and the total distribution load factor. Energy-cost based on annual class kWh share.  Allocation of transmission costs based on 1 CP.	<u>Demand-related</u> : 12 CP, each month weighted according to marginal monthly demand cost.  <u>Energy-related</u> : class kWh share in each month, weighted by monthly marginal energy costs
<b>Treatment of Off-System Sales/Revenue</b>	Revenues from long-term contracts credited as generation (100% energy); short-term sales credited as transmission (100% demand-related)	Surplus energy sale revenues are first used to offset transmission costs associated with these sales. Residual revenues are classified as 100% energy-related and credited to the generation revenue requirement.	No information available.	Contracts >1 year are treated as a class for allocation purposes. Company keeps excess revenues from the class. Revenues from short-term sales are credited to all jurisdictions and classes based on kWh.

	<b>Manitoba Hydro</b>	<b>Newfoundland &amp; Labrador</b>	<b>Northern States Power Co.</b>	<b>Ontario Hydro</b>
<b>% of Hydro Cap &amp; Off-System Sales</b>	90% of capacity is hydro Off-system sales as a % of total sales: 42% in 2001, 42% in 2002, 34% in 2003.	66% of capacity is hydro.	Hydro represents 5% of the total capacity. Off-system sales are 27% of total sales in MN, ND, SD, WI and MI.	31% of total capacity is hydro; 2% were off-system sales.
<b>Year of Latest Emb. COS</b>	2002	2002 (2003 General Rate Application)	WI: 2003; MN, ND, SD: 1992; MI : 1997	1989 generation and 2000 transmission
<b>Classification Method</b>	<u>Generation</u> : Classification is as follows: SLF* (Gen+Tran.) = Energy-related [1-SLF]*Gen- SLF*T = Demand-related <u>Transmission</u> : 100% demand-related	System load factor for hydro plants Plant-specific LF for oil-fired plant 100% fixed costs are demand related for Gas Turbine and Diesel Variable costs: energy-related except for diesel and gas turbine fuel cost in the Island Int. and Labrador Int. Purchase costs: system load factor. Transmission: 100% demand;	In WI, MI: 100% of fixed generation costs are treated as demand-related. In MN, SD and ND: classification based on Cap-Sub method.  All transmission costs are treated as demand-related.	<u>89 COS study</u> : Classification of all generation costs based on negotiated percentage factors (42% demand-related, 58% energy-related).  <u>Currently</u> : 100% generation costs classified as energy-related (market prices).  <u>Transmission</u> : 100% demand
<b>Time-Differentiation</b>	No time-differentiation	No.	In MN, SD and ND demand costs are allocated to 2 seasons using factors derived from average level of demand in excess of annual minimum demand. Energy costs are time-differentiated within the day (see below). There is no time-differentiation in WI, MI.	<u>89 COS study</u> – Two seasons: Winter/Summer and two daily periods (peak/off-peak). Energy and generation capacity costs are time-differentiated based on an analysis of hourly system incremental energy costs. <u>Currently</u> : Customers not subject to rate freeze pay hourly market prices.
<b>Allocation Method</b>	<u>Demand-related generation costs</u> : class' load share of the average of the top 50 hours of winter load and top 50 hours of summer load. <u>Demand-related transmission costs</u> : class' contribution to 12 monthly CP <u>Energy-related generation costs</u> : annual class' kWh share	<u>Demand-related</u> costs: Single CP <u>Energy-related</u> costs: class kWh share	<u>Demand-related cost</u> : MN, SD and ND: 1CP in each season; WI, MI: 12 CP. <u>Energy-related costs</u> : Peak and off-peak usage, weighted by system marginal energy cost in MN, SD and ND. Annual class' kWh share in all other states.	<u>89 COS study</u> : Demand-related generation costs: average of 6 NCP method within season; Energy-related generation costs: class kWh share within period and season. <u>Currently</u> : Customers not subject to rate freeze pay hourly market prices.  <u>Transmission</u> : Networks: Monthly CP or 85% NCP during peak. <u>Transformation and Connection</u> : monthly NCP
<b>Treatment of Off-System Sales/Revenue</b>	Export revenues (net of the associated fuel, purchase costs and water rental fees) are credited to domestic classes in proportion to the class' total allocated generation and transmission costs.	Newfoundland serves energy to an IOU utility, that is considered as a separate customer class in the COS.	In MN, SD, ND, WI, MI: revenues credited to native customers; classification based on contract charges.	<u>89 COS study</u> : Revenues from external sales credited proportionally to fixed and variable generation costs, before classification. <u>Currently</u> : not applicable.

	<b>Pacificorp</b>	<b>Salt River Project</b>	<b>Tennessee Valley Authority</b>
<b>% of Hydro Gen &amp; Off-System Sales</b>	15% of capacity is hydro; 32.4% of total sales in 2002 were off-system.	5% of generation capacity is hydro Sales for resale were 38% of total sales in 2002.	8% of TVA's energy comes from hydro plants. 84.2% of TVA's total sales in FY2002 were for resale.
<b>Year of Latest Emb. COS</b>	2003	2002	2003
<b>Classification Method</b>	Fixed costs: arbitrary percentages (75% demand, 25% energy). Variable costs: all demand-related except for fuel. Firm purchases: 75/25 Non-firm purchases: 100% energy.	System-load factor to classify fixed generation costs. Variable O&M and fuel are energy-related. Purchase power costs classified based on fixed/variable contract charges. Transmission: Step-up and switching facilities at generators are functionalized to generation; all other transmission costs are classified as demand-related.	Transmission and all generation costs are demand-related except for fuel, purchased power, corrective maintenance and a portion of research and development.
<b>Time-Differentiation?</b>	No	No	No
<b>Allocation Method</b>	<u>Demand-related</u> costs: Average of 12 CP <u>Energy-related</u> costs: class kWh share	Demand-related based on average CP in 4 summer months. Energy-related based on class kWh share.	<u>Demand-related</u> costs: A range of CP allocators (1CP, 2CP, 12CP, S/W CP; Hybrids: 1CP/12CP, 2CP/12CP). Lower hydro costs allocated to residential customers only. <u>Energy-related</u> costs: class kWh share. They are considering allocation based on hourly load-weighted market energy prices.
<b>Treatment of Off-System Sales/Revenue</b>	Revenues are credited to generation: Firm-sales: 75% demand, 25% energy Non-firm sales: 100% energy	Resale is a separate class, costs allocated based on the methods outlined above. The demand component of purchases is not assigned to resale class. Revenues in excess of costs allocated to resale class are not credited back to retail classes.	Revenue credited to generation costs. Classification in the same proportion as total generation costs.

## A. Classification and Time-Differentiation

Of the utilities with significant hydro capacity, all use generation classification methods that identify a large portion of hydro costs as energy-related, and several use marginal cost/market price relationships:

- BC Hydro (87% hydro) used in its last COS study (1996/97) the cap/sub method for fixed hydro costs and classified thermal fixed costs as 100% demand-related. Water rental fees were classified 84.7% to energy and 15.3% to demand, based on the variable and fixed components of the fees. There was no time-differentiation
- BPA (67% hydro) uses monthly market prices of energy and capacity (defined as the delta above the annual average market price of energy) to classify generation revenue requirements, with the energy portion a residual after subtracting capacity and “load variance” costs.<sup>36</sup> The classification yields separate costs for each month.
- Hydro Quebec (97% hydro) used in its 2001 rate filing the load factor method, using a distribution system load factor of 67.3% to classify energy-related costs. There was no time-differentiation
- Idaho Power (58% hydro) used in its rate filing this year the load factor method (55.26%). The classified costs were seasonally-differentiated using marginal cost relationships.
- Newfoundland & Labrador (66% hydro) used in its rate filing this year system load factor for classifying hydro plants, plant-specific load factors for classifying oil-fired plant, and classified 100% of fixed costs of gas turbines and diesels as demand-related. Variable costs were classified as energy-related except for some diesel and gas turbine fuel. There was no time-differentiation.

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<sup>36</sup> Load variance cost is the cost of BPA’s standing by to serve, at a fixed price, and unknown quantity at an unknown cost.

- Ontario Hydro (before restructuring) computed COS using a wide range of classification methods and negotiated 58/42 energy/demand classification factors. The classified costs were assigned to two seasonal and two diurnal periods based on an analysis of hourly system incremental energy costs.

The utilities that are actively participating in competitive wholesale markets (or were preparing to do so when the last COS study was undertaken) and have large export sales relative to domestic sales use a wide range of allocation methods; however, many incorporate marginal costs/market prices in their approach:

- TVA (84% of sales at wholesale) classifies fuel, purchased power, corrective maintenance and a portion of research and development as energy-related, all other generation costs is considered demand-related. There is no time-differentiation, although TVA is considering an energy allocation method involving hourly market energy prices.
- BPA (79% of sales at wholesale) uses monthly market prices.
- Salt River Project (38% sales for resale) classified fixed generation costs based on system load factor, variable generation costs as energy-related, and purchases according to fixed/variable charges in contracts.
- PacifiCorp (32% off-system sales) used arbitrary classification factors – fixed costs and firm purchase costs were classified 75/25 demand/energy; fuel costs 100% energy-related and other variable costs 100% demand-related; non-firm purchases 100% energy-related. There was no time-differentiation.
- BC Hydro (30% off-system sales) used in its last COS study (1996/97) the cap/sub method for fixed hydro costs and classified thermal fixed costs (a small amount of total capacity) as 100% demand-related. Water rental fees were classified 84.7% to energy and 15.3% to demand, based on the variable and fixed components of the fees. There was no time-differentiation.

- Northern States Power (27% of its Midwest<sup>37</sup> sales are off-system) used Cap-Sub classification for fixed costs, allocated demand-related costs using a seasonal measure based on average demand in excess of annual minimum demand, and time-differentiated energy-related costs in MN, SD and ND within the allocation step using marginal cost relationships.

Some of the surveyed companies functionalize all transmission facilities and associated costs to transmission, while others treat step-up transformers and switching stations as well as transmission connecting remote generators as part of the generation function. All treat functionalized transmission costs as 100% demand-related, except for PacifiCorp, which uses the same 75/25 demand/energy split used for fixed generation costs.

## B. Allocation Methods

Allocation methods for demand-related costs observed in the survey take a fairly broad approach to defining cost responsibility. Only one company uses the single-CP approach.<sup>38</sup> Another uses average CP during the 4 summer months.<sup>39</sup> Several use average of 12 CP.<sup>40</sup> One uses the relationship between class load factor and distribution system load factor.<sup>41</sup> Several use monthly, seasonal, or average seasonal CP or NCP to allocate demand-related costs that have already been assigned to months or seasons during an earlier step of the process,<sup>42</sup> thereby incorporating marginal cost/market price information in the allocation process. The rest use methods prescribed by legislation or negotiated with wholesale customers.<sup>43</sup>

The surveyed utilities all use some measure of energy consumption to allocate energy-related costs. Those that time-differentiate energy-related costs use energy use within the costing period, which means that marginal costs/market prices used in the time-differentiation

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<sup>37</sup> MN, ND, SN, MI, WI.

<sup>38</sup> Newfoundland & Labrador.

<sup>39</sup> Salt River Project.

<sup>40</sup> BC Hydro; Northern States Power Energy in WI and MI; PacifiCorp.

<sup>41</sup> Hydro Quebec.

<sup>42</sup> Ontario Hydro; Northern States Power Energy in MN, SD and ND; Idaho Power.

<sup>43</sup> BPA and TVA.

step are reflected in the allocations. TVA is considering an energy allocation approach that would use hourly consumption weighted by hourly market energy prices.

Note that although BPA's allocation methods are prescribed by law, they can be overridden if a cost-benefit analysis reveals that a particular class has been allocated costs that exceed benefits. This introduces a market test in the COS process.

### **C. Treatment of Revenues from External (Off-System) Sales**

For utilities with significant export sales, a key element of class revenue allocation is the treatment of revenues from those off-system sales. The options include: (1) treating export customers as class (or classes), so that generation (and transmission) costs are allocated to exports, leaving only net revenues to be functionalized, classified and allocated as credits to other customers or retained by shareholders; (2) directly assigning only easily identifiable variable costs (e.g., fuel and purchased power, if any) of supplying export sales, and treating the remainder of export revenues as profits, to be functionalized, classified and allocated among customer classes (and shareholders) on some basis; or (3) directly assigning variable costs to export customers and returning the net export revenues to Government to be used to reduce taxes or support social programs.

Among the surveyed utilities, three utilities (Newfoundland and Labrador Hydro, Salt River Project and Idaho Power) created a separate class for external sales. In the case of Idaho Power, only longer-term sales (greater than one year) are included as a separate class. Newfoundland charges its wholesale customer on the basis of the COS study, so there are no net revenues collected. Salt River Project does not credit net export revenues within the COS study, although these revenues are taken into account in the rate-setting process. Idaho Power keeps any net revenues from long-term sales, but credits revenues from short-term sales on a per-kWh basis.

The remaining utilities credit the entire revenue from off-system sales (less direct variable costs of such sales) to their domestic customers. BC Hydro functionalizes net revenues from long-term contracts as generation and classifies them as 100% energy-related. Short-term

net revenues are functionalized to transmission and classified as 100% demand-related.<sup>44</sup> BPA first uses supply energy sale revenues to offset transmission costs associated with these transactions, then functionalizes the remainder as generation and classifies it as 100% energy-related. In its 1989 study, Ontario Hydro functionalized export revenues as generation and classified them to energy and demand in proportion to the size of these cost categories. PacifiCorp also functionalized off-system revenues to generation and classified long-term contract revenues in the same fashion as generation fixed costs (75/25 demand/energy) and short-term revenues as 100% energy-related. TVA functionalizes off-system sales revenues to generation and classifies them as demand/energy-related in the same proportion as total generation costs (approximately 65% demand, 35% energy). Northern States Power functionalizes the revenues to generation and classifies them as demand/energy based on the fixed/variable structure of the contracts.

## VI. COS METHODS TESTED

A review of the standard methods for classifying and allocating generation costs,<sup>45</sup> the survey results, and the selection criteria<sup>46</sup> provides guidance for selecting methods suitable for quantitative analysis for Manitoba Hydro. The methods ultimately adopted by Manitoba should, at a minimum, (1) be time-differentiated, (2) incorporate marginal costs/market prices to some extent, and (3) recognize that Manitoba Hydro's load patterns across the year are heavily influenced by export sales.

Some methods are clearly not suitable for Manitoba Hydro:

- Fixed/Variable classification method: This approach is not appropriate for a primarily hydro system, where the significant fixed costs of the hydro facilities are clearly incurred, to a large extent, to produce very low cost energy.

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<sup>44</sup> New regulations from the Heritage Contract, which will take effect on April 1, 2004, require the Commission to include in its forecasts of BC Hydro's net income a forecast of Trade Income that may not be greater than \$200 million (2003 Trade Income was \$1,932 million), nor less than zero. Under this measure ratepayers continue to get some benefit of Trade Income and are protected from trading losses. Source: "Heritage Contract for BC Hydro's Existing Generation Resources, Stepped Rates and Transmission Access Proposal" filed with the BCUC on April 30, 2003 (BC Hydro's website [www.bchydro.com](http://www.bchydro.com)).

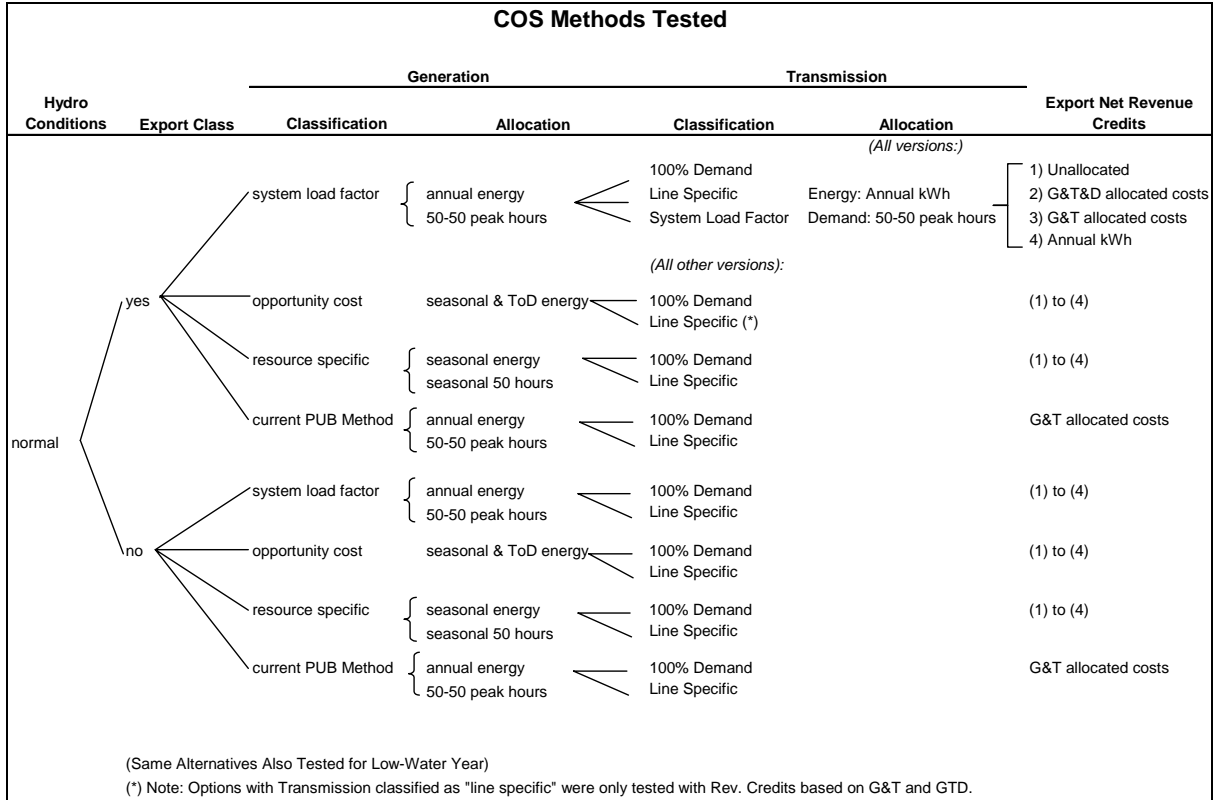
<sup>45</sup> See Section II.D.

<sup>46</sup> See Section III.



- **Cap-Sub classification method:** This method quantifies the capacity-related component of generation costs using the cost of a peaker (or perhaps the market value of capacity), with the energy component determined by the residual. As a result, any particularly high or low cost investments distort the energy portion. For example, a company with large cost over-runs on a nuclear plant would have all the over-runs classified as energy costs under this method. A company that has been able to exploit inexpensive-to-develop hydro sites would understate the energy-related portion of the hydro facilities using this approach.
- **Narrow demand allocation methods:** Demand allocators such as traditional single-CP, 2-CP, 4-CP, or even 12-CP allocate all demand costs based on class usage in just a few (1-12) hours of the year and do not reflect the fact that system planners consider many more hours critical for capacity planning purposes.

To quantify the effects of various methods and combinations of methods and the degree to which they meet key selection criteria, Manitoba Hydro ran its COS model using a large number of approaches and combinations of approaches. All of the runs were based on assumptions for test-year 2003/4. The chart below shows the methods tested. Each approach is described in detail in the sections below.



## VII. IMPLICATIONS FOR CLASS REVENUE ALLOCATION AND RATE STRUCTURE

### A. Exports as a Class

Two sets of studies were prepared. one exports treated as a separate class, with costs allocated to the export class in the same way that they are allocated to other classes. The other directly assigns only water fees and fuel costs to exports and treats remaining net export revenues as credits to the domestic classes. In the scenarios with an export class, the loads used to compute load factors and allocation factors include the exports, and there is no direct assignment of water fees and fuel costs to exports before the allocations are done.

Creation of an export class to which costs can be assigned using standard allocation factors recognizes the facts that (1) exports are a very large share of Manitoba Hydro’s business, (2) the revenues from exports can vary widely because of hydro availability and market conditions, and (3) the utility specifically plans and operates its system with exports in mind, although it does not currently build solely for export. Inclusion of an export class makes it obvious that the export sales are covering their full embedded cost of service. Including an

export class would also tend to reduce year-to-year variations in class revenue requirements from fluctuations in export prices. In addition, treating exports as a class reduces the net revenues to be credited back to other customer classes, which may make the methods used for that crediting less controversial. Furthermore, identification of the above-cost revenues from exports sales as “profits” would emphasize the fact that these revenues are available to support a variety of objectives, and do not necessarily have to be functionalized, classified and allocated (credited back) to other classes within the COS study.

If certain costs are incurred specifically for the export class, they should be directly assigned to this class before the rest of the allocation process takes place. For example, if costs of the trading floor or Interties were exclusively incurred to facilitate exports, these costs could be directly assigned to exports. However, the trading floor and Intertie benefit domestic customers too by facilitating power purchases to serve domestic load.

Manitoba Hydro’s current COS approach directly assigns to exports only the variable power purchase, fuel and water rental costs associated with export sales. This approach was not used in the with-export-class tests for this report. Instead, all variable generation costs were allocated to classes using the same allocation factors. The current direct-cost allocation approach for exports is inconsistent with the concept that all customers contribute to the total load curve that must be served at a given moment. Of course Manitoba Hydro should not make export sales at prices less than incremental cost, and net export revenues are used to reduce domestic rates.<sup>47</sup> Therefore, domestic customers benefit from the export sales even if incremental costs associated with exports are allocated to both export and domestic classes.

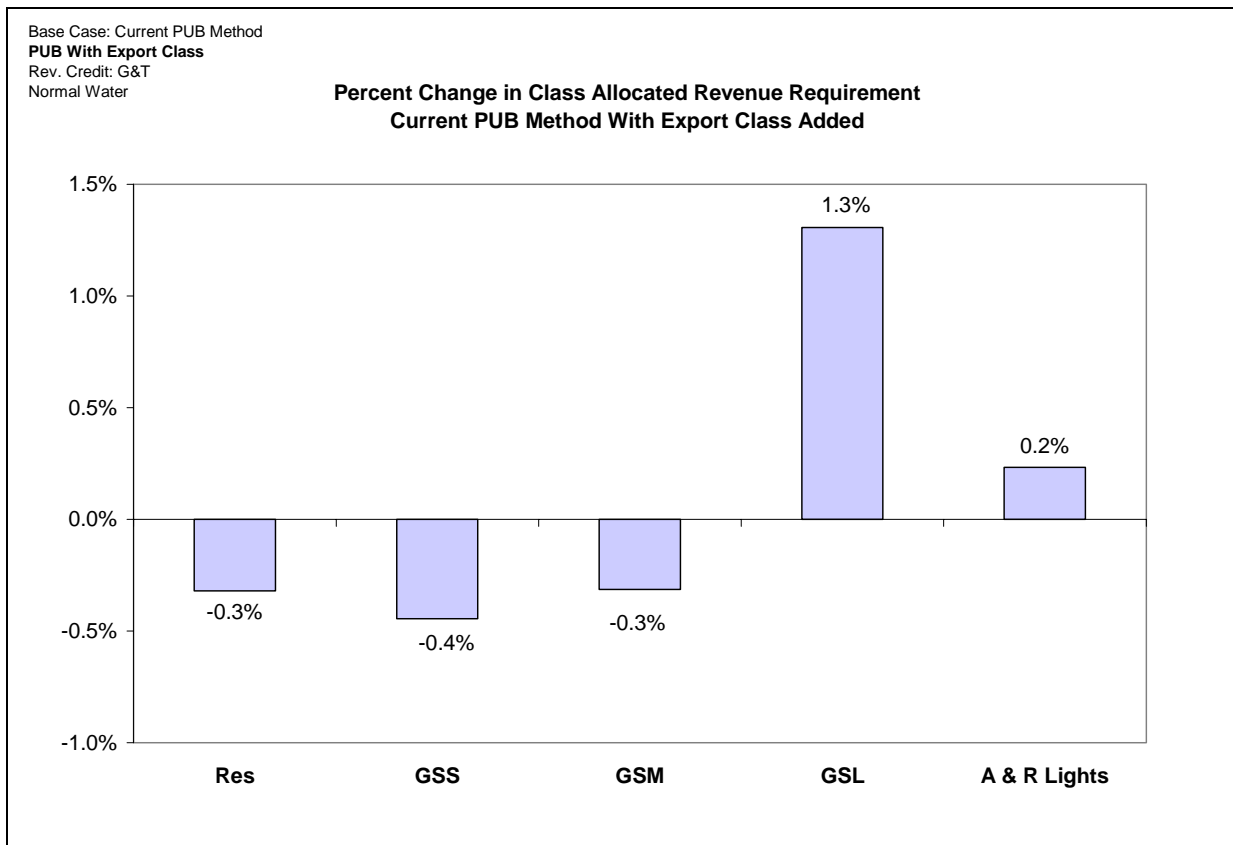
Continuing to treat exports as incremental load “on top” of domestic load for purposes of allocating variable generation costs as well as allocating a share of embedded costs to the export class is a possibility, but that method was not tested for purposes of this report. That approach would reduce the net export revenues to be credited to other classes, which might make the crediting method less controversial. However, it is our judgment that the test of whether export revenues are sufficient to avoid causing cross-subsidies from domestic to export customers should be done outside the embedded COS study. Furthermore, the comparison should be of incremental costs (in most cases the opportunity cost of Manitoba Hydro’s

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<sup>47</sup> Or, potentially, reduce taxes.

capacity and energy) with incremental export revenues. Embedded costs should not be a factor in this analysis and including them could lead to lost opportunities to make profitable sales to export customers. For example, if embedded costs were included in the floor price offered to export customers and the price was thereby higher than the market price, Manitoba Hydro would lose the sale and the opportunity to earn revenues that would offset embedded costs. Naturally the decision to accelerate construction of new generation for the purpose of making export sales should be based on likely revenues from those export sales. But once the capacity is built, Manitoba Hydro should offer energy to the export market as long as the incremental cost is covered by the price received.

The chart below illustrates the effect on class revenue allocations of adding an export class and using the same allocation method for this class as for the other classes, but keeping all other methods unchanged. The changes are relatively minor.



**Because there are so many reasons for adding the export class, and the effects on class allocated revenue requirements are minor, we recommend that the export class be**

**used in the COS study, and that costs be allocated to this class using the same methods as for the domestic classes.** The results of other COS alternatives shown in the charts below are based on the assumption that the export class is added.

## **B. Generation Classification, Time-Differentiation and Allocation Methods**

Three classification/time-differentiation approaches for generation were tested: (a) *System Load Factor*, (b) *Marginal/Opportunity Costs* and (c) *Resource Specific*. The characteristics of these methods are described below.

### **1. System Load Factor (SLF)**

Use of the system load factor to classify generation costs for this report is different from the approach used in Manitoba Hydro's most recent COS study, in which the load factor was applied to the sum of generation and transmission costs, with the transmission component then classified as 100% demand, leaving a generation residual. The method we tested applies the SLF percentage exclusively to total generation costs.

The SLF used in our tests varies depending on whether the scenario contains an export class. The implicit time-differentiation is inherent in the choice of allocation factors; we used equal weights for summer and winter demand allocation factors and no time-differentiation of energy-related costs. For the SLF runs, energy-related costs were allocated on the basis of annual energy use and demand-related costs on the basis of the class contribution to the 50 highest winter and 50 highest summer hourly peaks (referred to as 50W/50S). The energy allocator fails to reflect the pattern of incremental cost/market situation; however, the demand allocator does use a broad definition of peak that is consistent with Manitoba Hydro's load pattern.

This approach is a traditional COS method, but fails to reflect incremental costs or market conditions. The lack of explicit time-differentiation means that the results are not useful for the development of time-differentiated rates.

### **2. Marginal/Opportunity Costs (MC)**

During many hours of the year (and perhaps most hours), Manitoba Hydro's marginal cost of supplying domestic load is determined by the price it would pay for an additional

purchase, or the revenue it would lose from selling less in the regional market as a result of the higher domestic load. In many markets there are separate prices of capacity and energy, and these prices vary by season and time-of-day. In those markets this approach would classify and time-differentiate total generation costs based on the relative size of the opportunity cost of capacity and energy within each costing period.

Because recent market prices for energy and capacity were not available separately, Manitoba Hydro used an average of seasonal peak and off-peak market prices per kWh in the Northern MAPP region, as reported by Platts, as a proxy for its opportunity cost of energy plus capacity. The two seasons are summer (May – October) and winter (November – April). The prices were averaged over the period January 2001 – September 2003 and an index was created that represents the relative prices in the two seasons and two diurnal periods. The use of a per-kWh market price means that all generation costs are classified as energy. However, the facts that peak-period energy prices often include some capacity element and that energy use by period is used to allocate the generation costs under this approach means that a capacity element is reflected in the class revenue requirements that result.

This approach comes closest to reflecting incremental costs and market conditions, which are key objectives for Manitoba Hydro. In addition, the method provides guidance for a cost-reflective time-differentiation in the rate design for each class.

The historical market energy prices used in this report are an example of how the method could be implemented, but are probably not the best proxy for Manitoba Hydro's marginal/opportunity cost, and further work would be necessary to identify a better measure. Options include the prices at which 'Surplus Energy' is sold to domestic customers, other market price indices, and prices in short-term contracts. The chosen option should reflect the extent to which transmission constraints make Manitoba Hydro's marginal cost dependent on the operating costs of its own resources in some hours, rather than on market prices.

Although forward-looking opportunity cost measures would be more appropriate, use of historical market prices over several years smoothes out short-term fluctuations that might cause class allocations and rate design to be excessively volatile, and avoids using commercially-sensitive forecasts.

### **3. Resource Specific Approach (RS)**

Each type of generation plant is classified and time-differentiated separately, based on an analysis of its role in system operations. Although the details of this approach would need to be refined if it were adopted for use by Manitoba Hydro, the COS runs for this report used the following proxy classifications:

- a. hydro and purchase costs - system load factor;
- b. thermal costs – classified 100% to demand and 100% to winter.

Thermal operating costs should ideally be classified to energy and assigned to the time-of-use periods when the thermal units run. However, the necessary data were not readily available for these tests. In addition, since thermal units are used for energy purposes in droughts, fixed thermal costs could be split between demand and energy based, for example, on average capacity factor over a period of years that includes a range of hydro conditions. The fixed cost time-differentiation could be refined using an analysis of the number of hours the units typically run in each costing period.

For the RS runs, energy-related costs were allocated on the basis of annual energy (for hydro and purchases)<sup>48</sup> and demand-related costs on the basis of the class 50W/50S. Use of seasonal energy consumption as the allocator for thermal energy-related costs improves the degree to which incremental cost/market situation is incorporated in the study. Again, the demand allocator is consistent with Manitoba Hydro's load patterns.

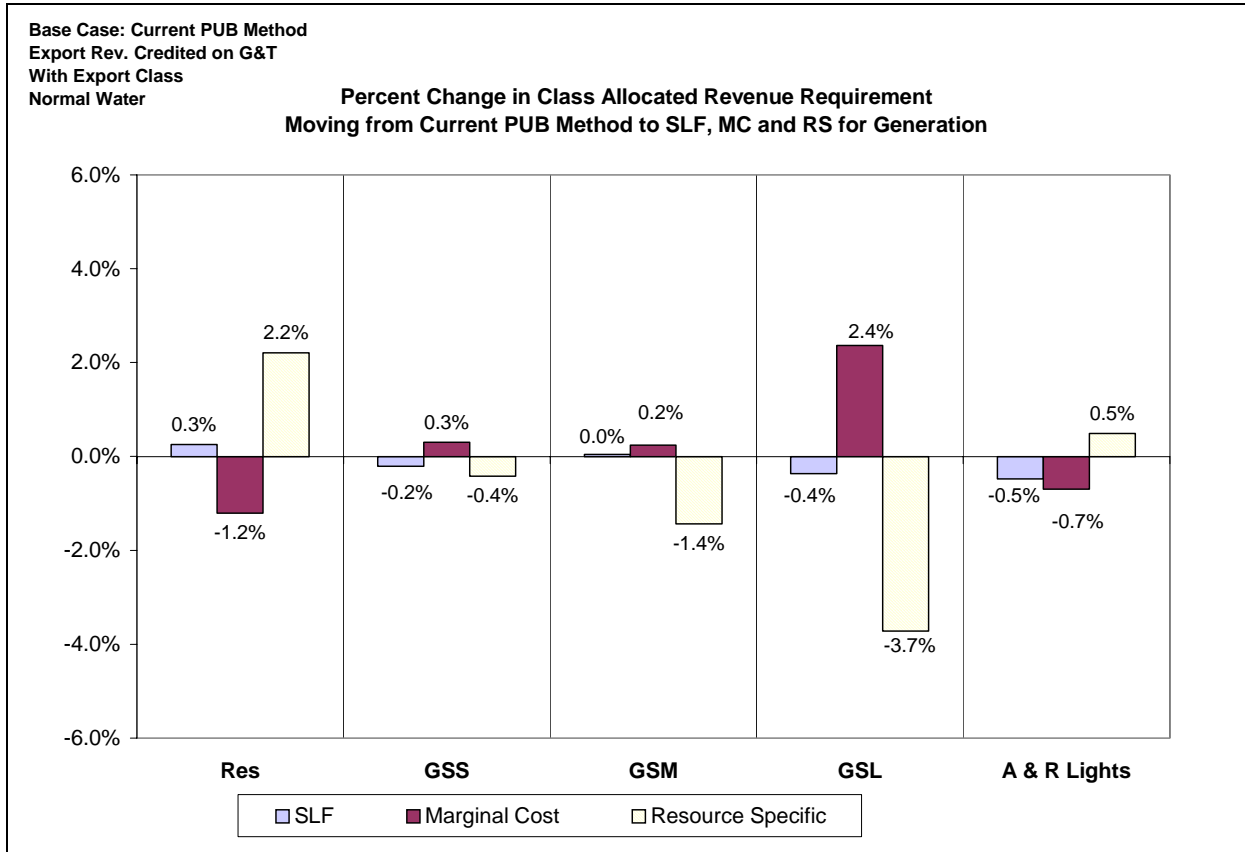
#### 4. Comparison of Methods

The chart below compares the effects of changing to the three alternative classification schemes described above, assuming an export class is added. Of the three, the resource specific approach has the largest effect because much more generation cost is classified on the basis of peak demands than under the current approach.

**Since the opportunity cost/marginal cost approach is most consistent with the objective of reflecting market conditions and it has limited effects on class revenue allocations, we recommend that Manitoba Hydro adopt this approach and work on identification of better measures of MC/opportunity cost.**

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<sup>48</sup> Energy-related costs would be allocated on the basis of class energy use by period (rather than by season) if a more detailed analysis of thermal plant and other types of generating unit operating hours were included.]

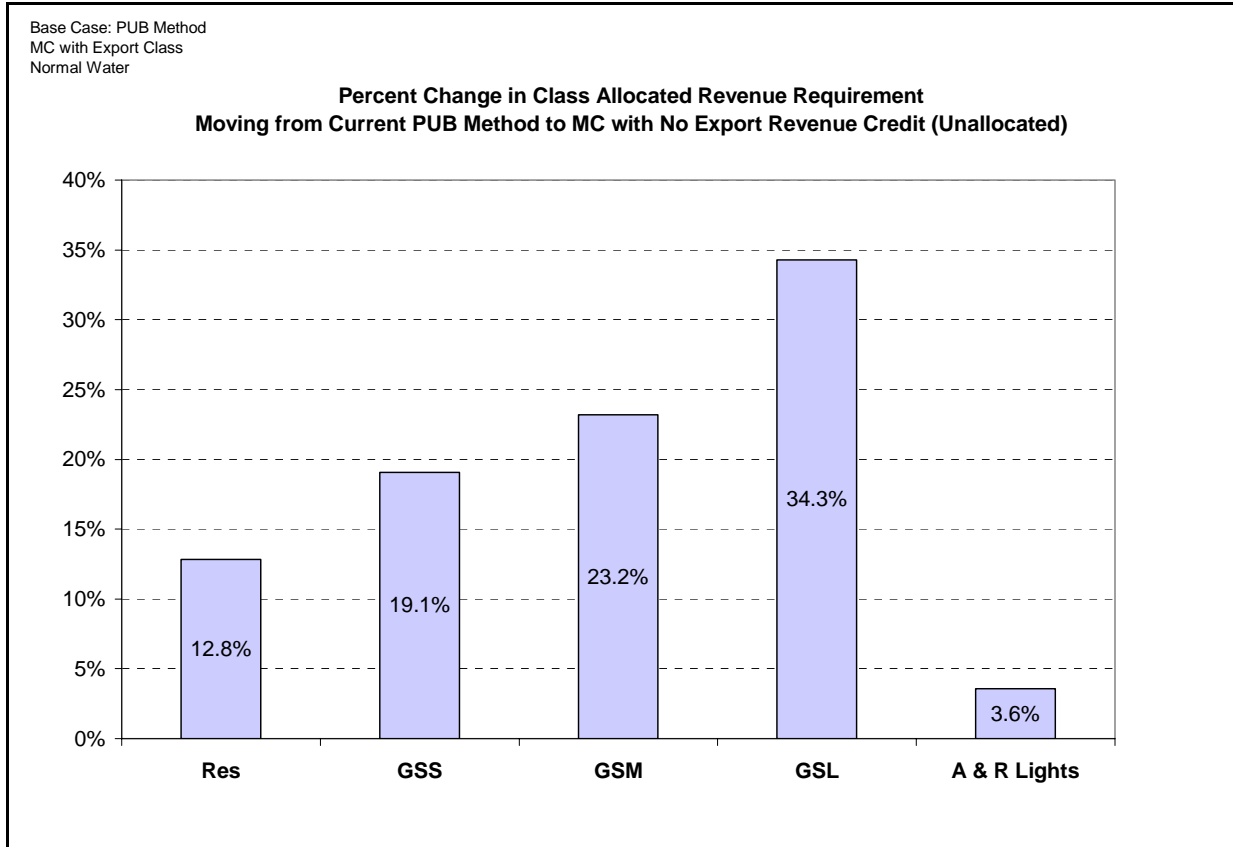


### C. Treatment of net export revenues

To illustrate the treatment of net export revenues under current policies, we computed the increases in domestic class revenues that would be needed if an export class were created, generation costs were classified using the marginal cost approach, and no net export revenue were used to reduce domestic electricity rates. The chart below illustrates the results and shows the relative benefits accruing to the various customer classes from the current method of dealing with export revenues.<sup>49</sup> Clearly, the large general service customers are the main beneficiaries of the Provincial hydro resources.

<sup>49</sup> Currently only variable costs are directly allocated to export customers. All export revenues net of these variable costs are credited on the basis of allocated generation and transmission costs.





The question of what to do with net export revenues must be answered in conjunction with the question of whether there should be an export class, because the magnitude and composition of the dollars is quite different. If there is an export class, the net revenues can be considered profits. If there is no separate export class, the export revenues are net only of directly identifiable variable costs (fuel, if any; water rental; and purchases needed in poor water years, if any). In this case the net revenues include capacity and other energy costs.

We tested three treatments of net export revenues:

1. **Allocate on the basis of total (generation, transmission and distribution--G&T&D) allocated costs.** This approach results in the same percentage reduction in revenue requirement for each customer class. This seems to be an inherently fair way to spread the benefits of export sales, particularly in the case where G&T costs have been separately allocated to an export class. Furthermore, if the results are carried through to rate design, the “distortions” created by the credits can be spread evenly across all rate elements and time periods, rather than crediting only a portion of the charges. If there is no export

class, the net export revenues include costs and profits, so it is more difficult to interpret the results of the allocation to the various domestic classes.

2. **Allocate on the basis of allocated G&T costs.** This approach would work with or without an export class. In the case without an export class, it is difficult to interpret the allocation of export benefits to the various domestic classes because the revenues credited are a combination of costs and profits. With or without an export class this approach gives smaller customers—for whom distribution costs are a larger share of total allocated costs than for larger customers— a smaller share of benefits than when revenues are credited on the basis of G&T&D costs. To the extent that profits on export sales are seen as deriving from Provincial resources, this smaller benefit for small customers may be seen as unfair. Furthermore, giving a large share of the benefits to large customers means that their rates are even further below efficient (marginal cost) levels than when benefits are spread more widely. Since large customers are generally thought to have more elastic demands for electricity, this approach can lead to more inefficient consumption (and therefore inefficient investment by Manitoba Hydro).
3. **Spread the profits to classes on the basis of annual energy consumption.** This approach is very simple to understand and to administer. It is more appropriate when there is an export class, so that embedded costs associated with export sales are not involved in the crediting of net revenues. This approach does give a larger share of benefits to customers with high load factor (more energy per kW of demand) than other methods because it uses only one dimension of electricity use (energy) as the allocation factor. Although this method is used by some utilities for sharing the benefits of a modest amount of nonfirm energy sales, it is probably not appropriate when the export revenues are as large as Manitoba Hydro's.

The next chart compares the changes in class revenue requirements that would be triggered by adopting the three tested approaches to net export revenue crediting. In each case

the opportunity cost/marginal cost approach is used for classification and an export class is assumed. **The most dramatic effects are from the G&T&D approach, which gives each class the same percentage benefit of the net export revenues. Since, of the methods tested, this is the least distorting approach and can be interpreted as the most equitable, it is the one we recommend.**

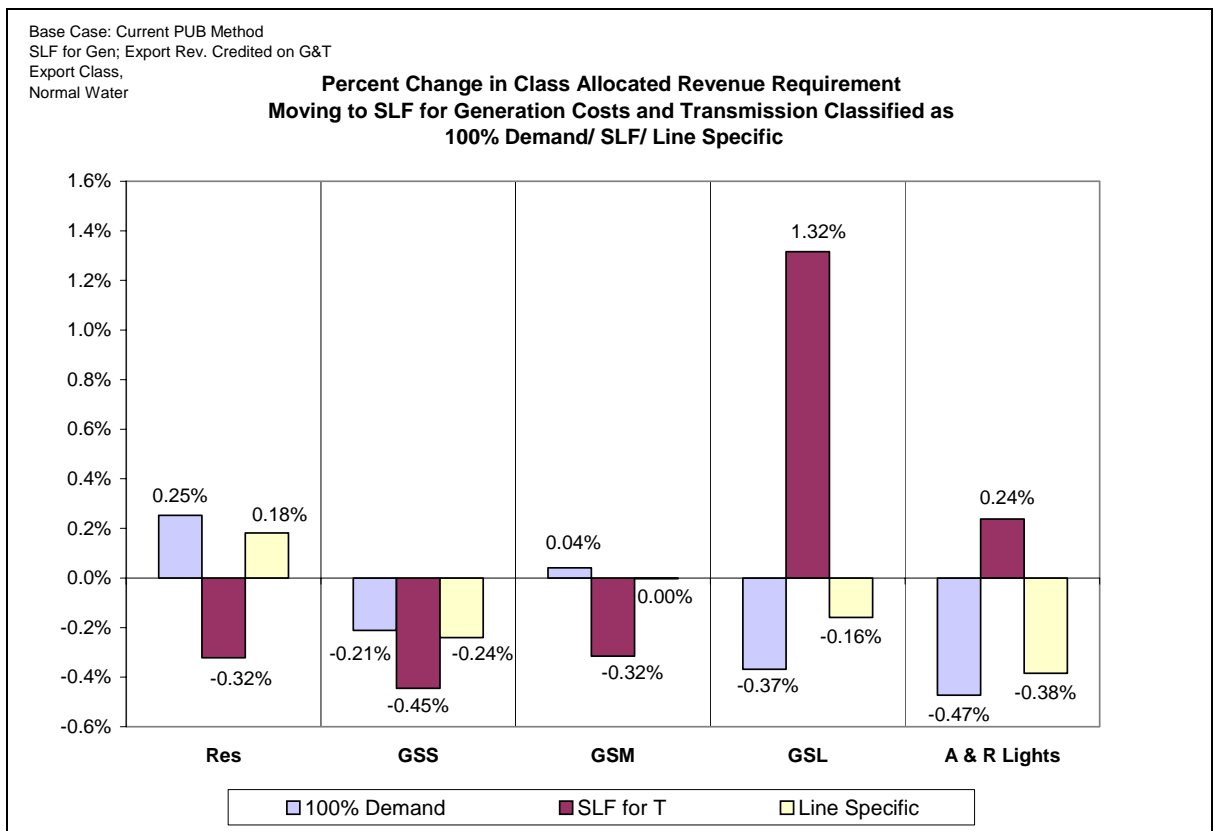
#### **D. Transmission Classification and Time-Differentiation Methods**

Three methods for classification of transmission costs were tested. The transmission options were variations of a single generation test (classification of generation using system load factor). The same time-differentiation used for generation was used for demand-related transmission costs, through the allocation process (using class demands in 50W/50S hours). The three transmission classification approaches were:

- 100% demand, with allocation based on class demands in 50W/50S hours. This approach (which is currently used by Manitoba Hydro) is very simple, but ignores the fact that some transmission investment is made at least partly to facilitate energy imports/exports.
- Same demand/energy split and allocation factors as for generation (we tested on the system load factor approach as an example). This approach is also simple, but also recognizes that some transmission investment is justified because it reduces energy costs (or permits energy exports) rather than being exclusively for purposes of giving access to capacity in peak hours.
- LineSpecific – This approach attempts to make a more precise distinction between transmission investment related to serving peak loads and that justified because it reduces energy costs or facilitates energy exports. For purposes of illustrating the method, since a detailed study has not been conducted, tie lines were classified as energy, remaining facilities as demand. Further analysis might be able to quantify the reliability v. energy transfer benefits of tie lines, or they could be classified in the same way that generation costs are treated. Further analysis might also show that some other lines should be classified as energy-related or a combination of energy and demand-related. Demand-related costs

were allocated using the 50W/50S hours approach and energy-related costs allocated using annual energy.

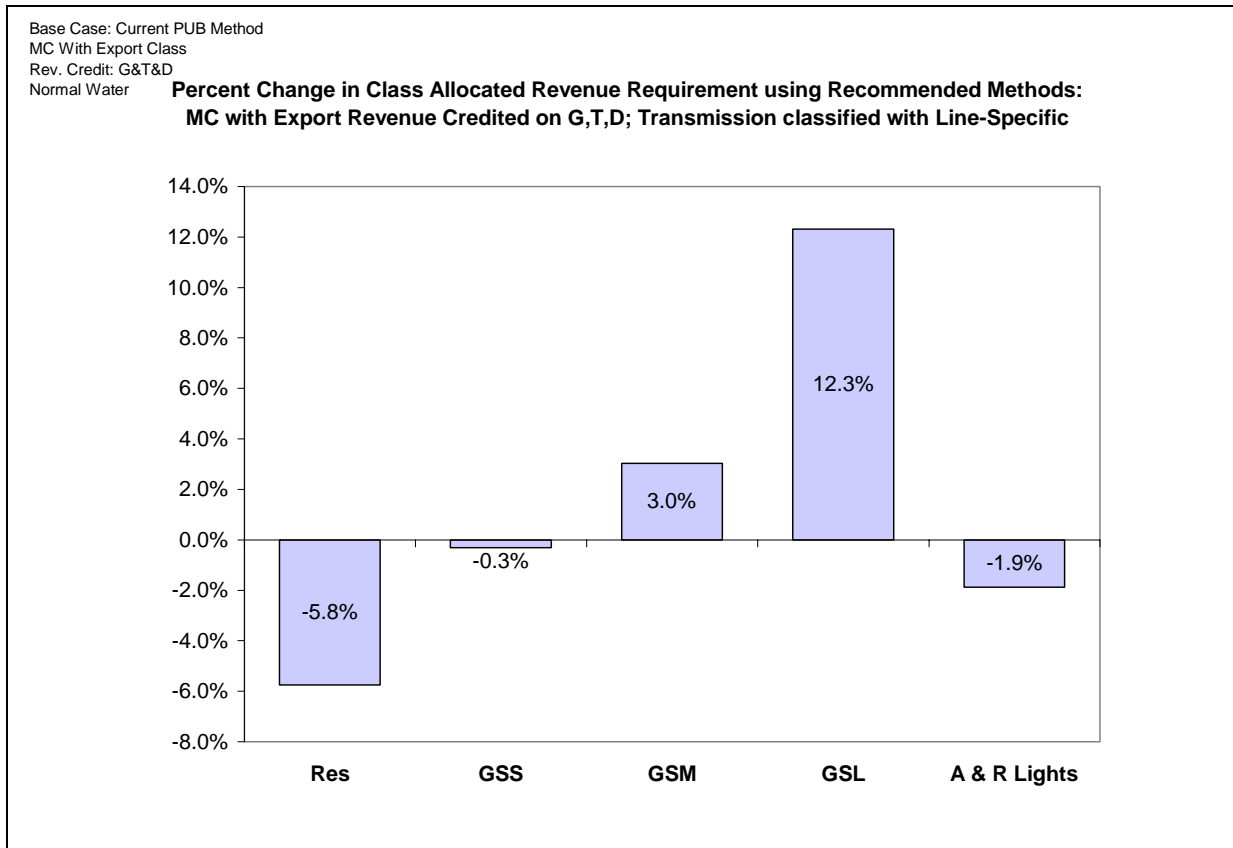
The chart below shows the changes that would result from using these three alternative approaches to transmission classification and allocation. In each case the system load factor approach has been used for generation and an export class has been included. The changes are not large. **Because the line-specific approach recognizes the multiple roles of various parts of the transmission system and explicitly reflects the role of Manitoba Hydro’s transmission in the regional market, we recommend this approach.**



**E. Effect of Combined Recommended Methods**

The chart below shows the effects of the combined recommended methods on class revenue allocations. Adoption of the recommendations would mean a significant increase in costs allocated to General Service Large customers and a noticeable reduction in costs allocated to Residential customers. These changes in class revenue requirements are the net result of all the recommended changes in COS methods; however, the most important methodological

change is the equal sharing of net export revenues (above costs allocated to the recommended export class).



## F. Multiple Water Years

Water conditions have a direct impact on short-term export sales and power purchases necessary to meet domestic loads and firm up export obligations. Although Manitoba Hydro's COS studies generally assume normal water conditions in the future test year (both for purposes of establishing costs and calculating load-related classification and allocation factors) it is useful to run a second set of COS studies, assuming adverse hydro conditions, in order to observe how sensitive the results are to this variable. A comparison of the results for normal and adverse hydro conditions, using the same combinations of methods illustrated in the charts above, is provided in the Appendix.

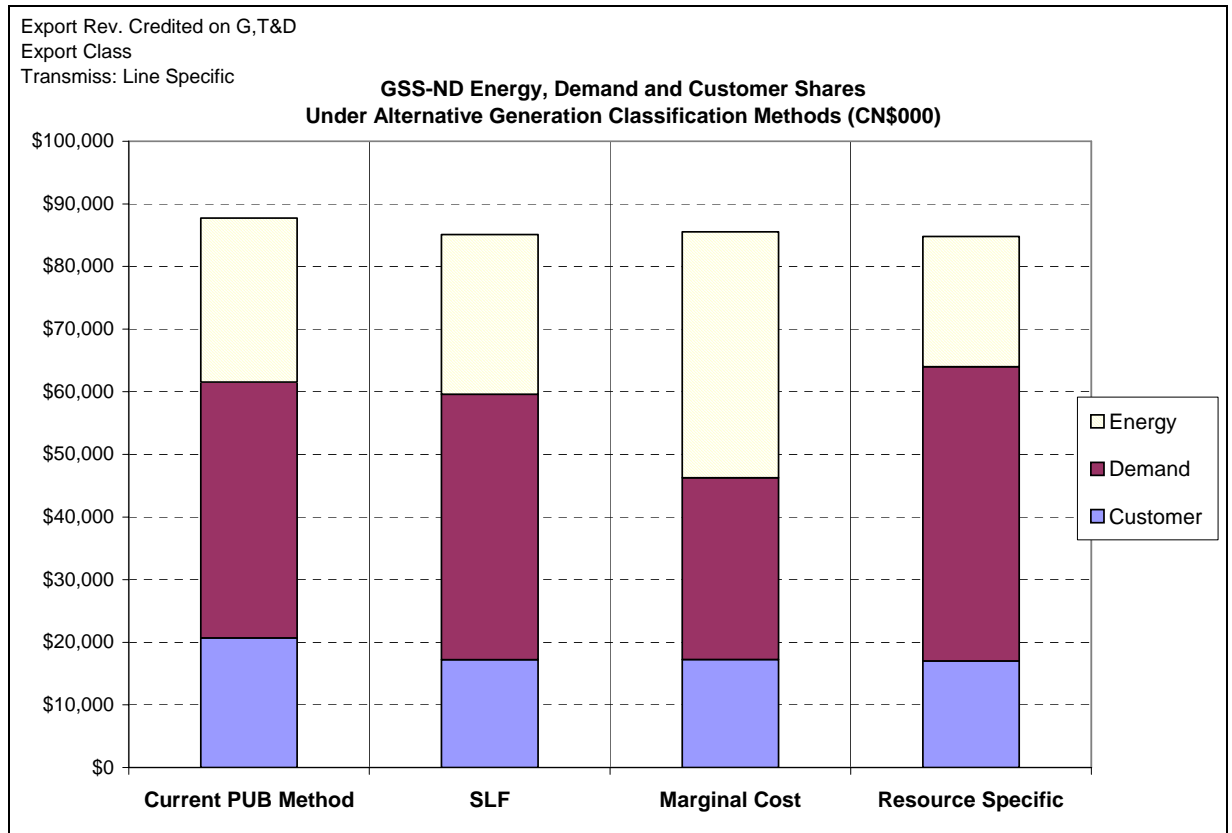
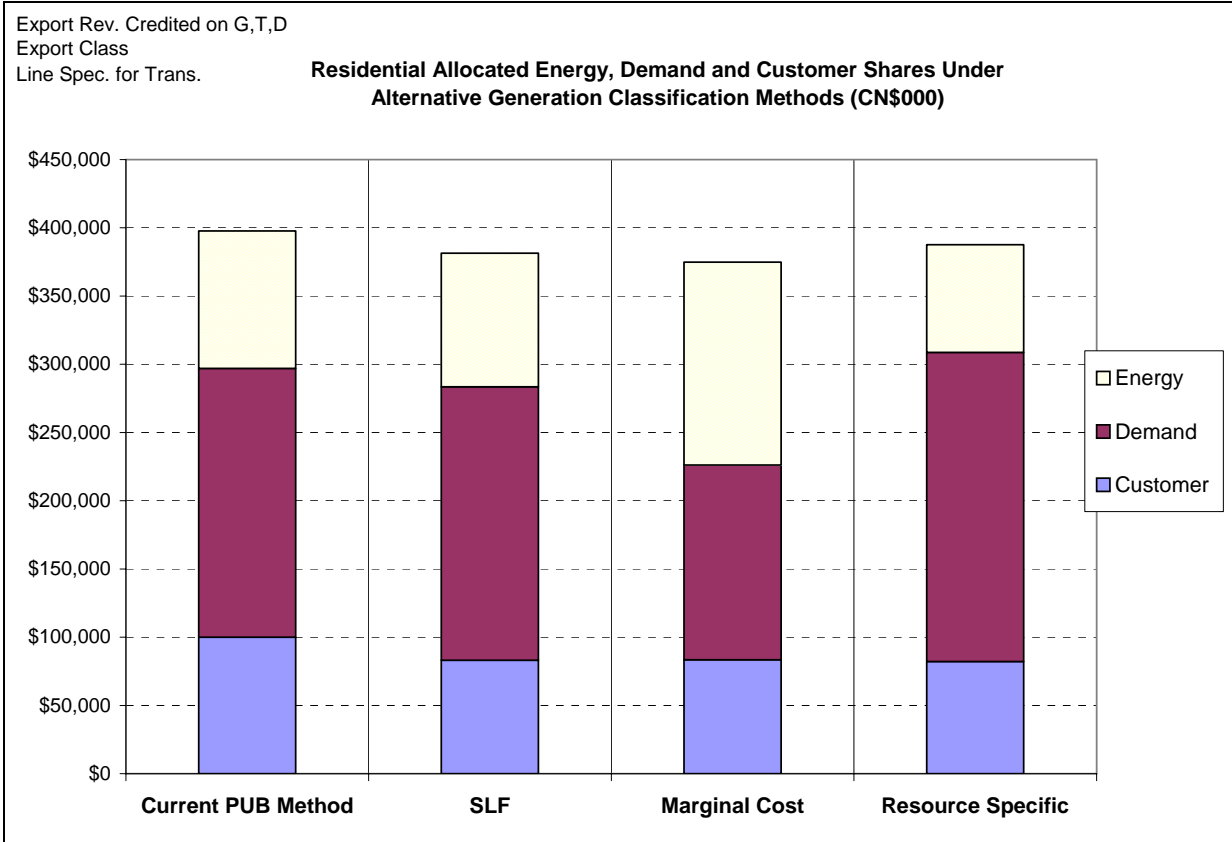
The COS runs for 2003/04 with low water conditions were made using high-level proxies, rather than completely redoing the COS study. The assumptions/changes made to reflect adverse hydro conditions were as follows:

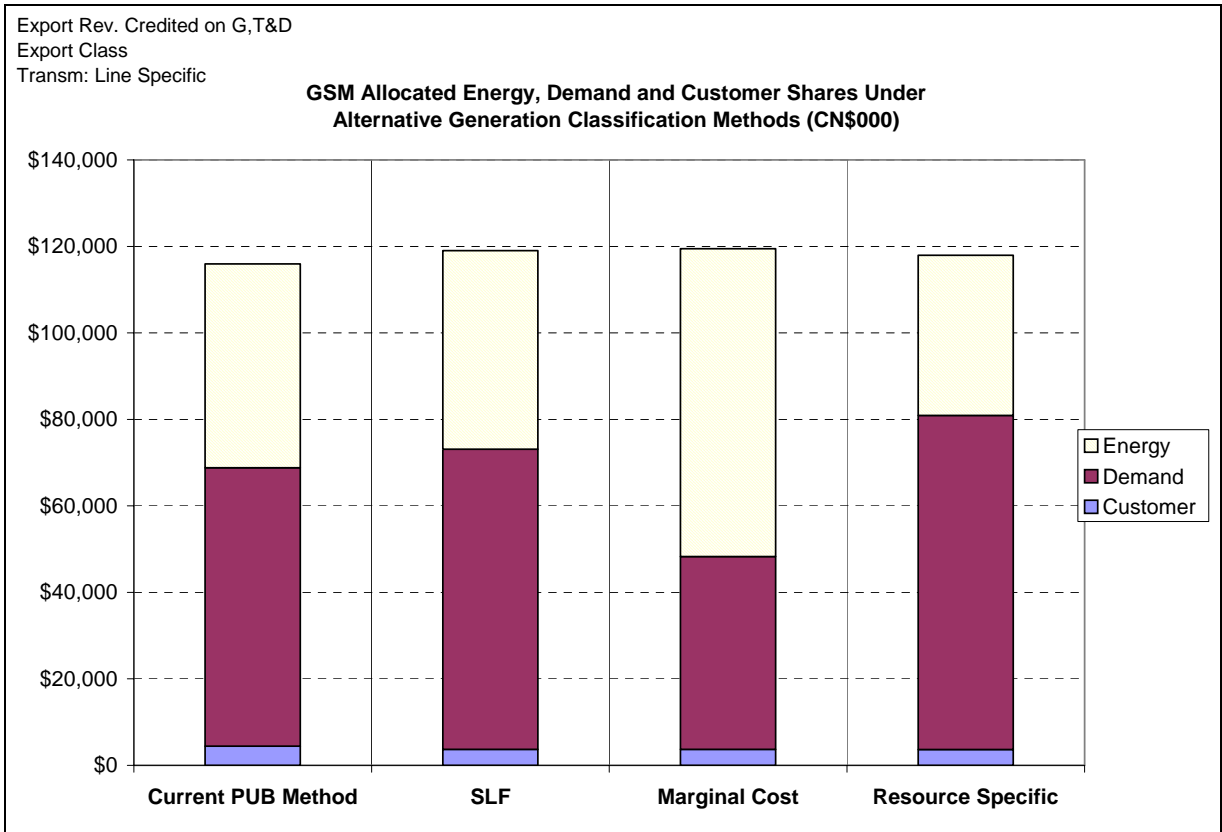
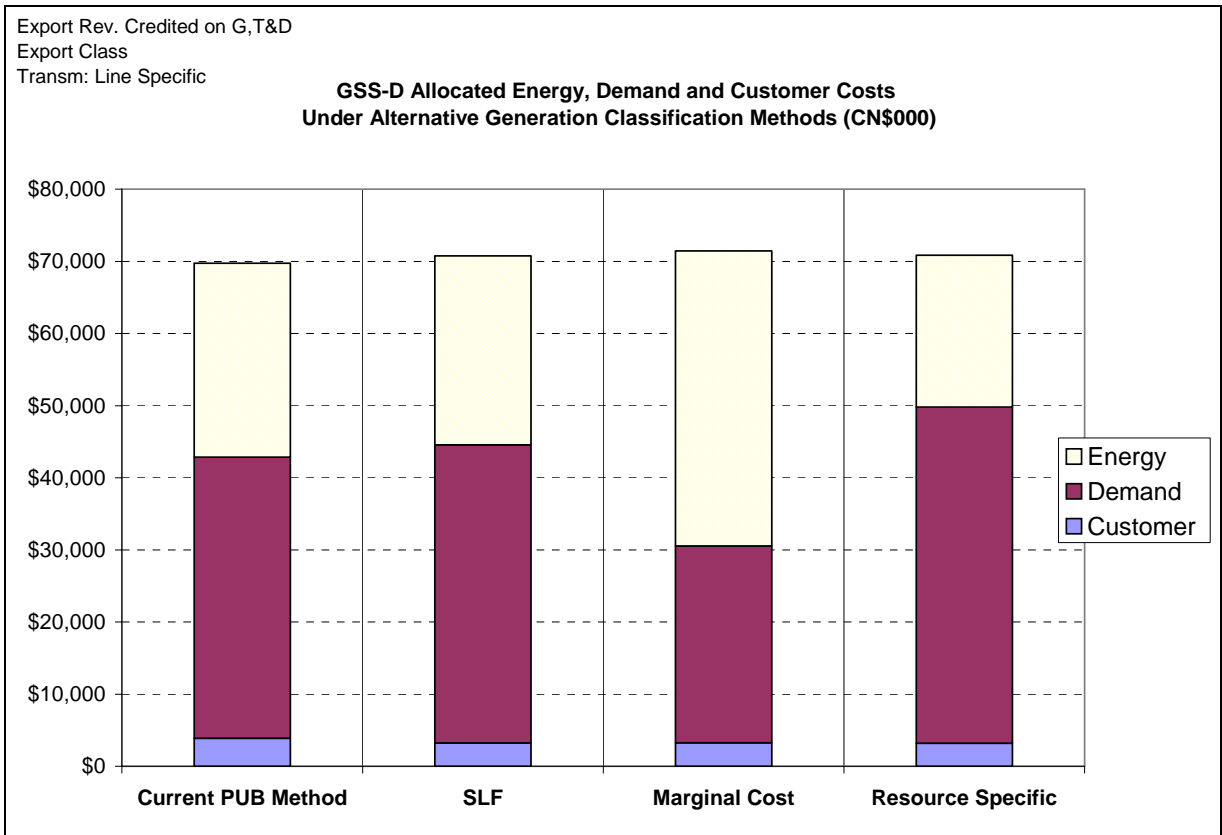
- In poor water years, revenues do not fully cover costs. Manitoba Hydro's COS results for the low water scenarios assume that revenues fall short of costs by CN\$355 million.
- Revised estimates of export sales, import purchases, and generation production were made, consistent with low hydro conditions.
- Adjustments were made to operating and depreciation expenses, based on the percentage changes in the normal hydro financial forecast between 2002/3 and 2003/4.
- Domestic loads were assumed to be unaffected by the low hydro, but exports were assumed to be reduced.

## **G. Implications for Rate Structure**

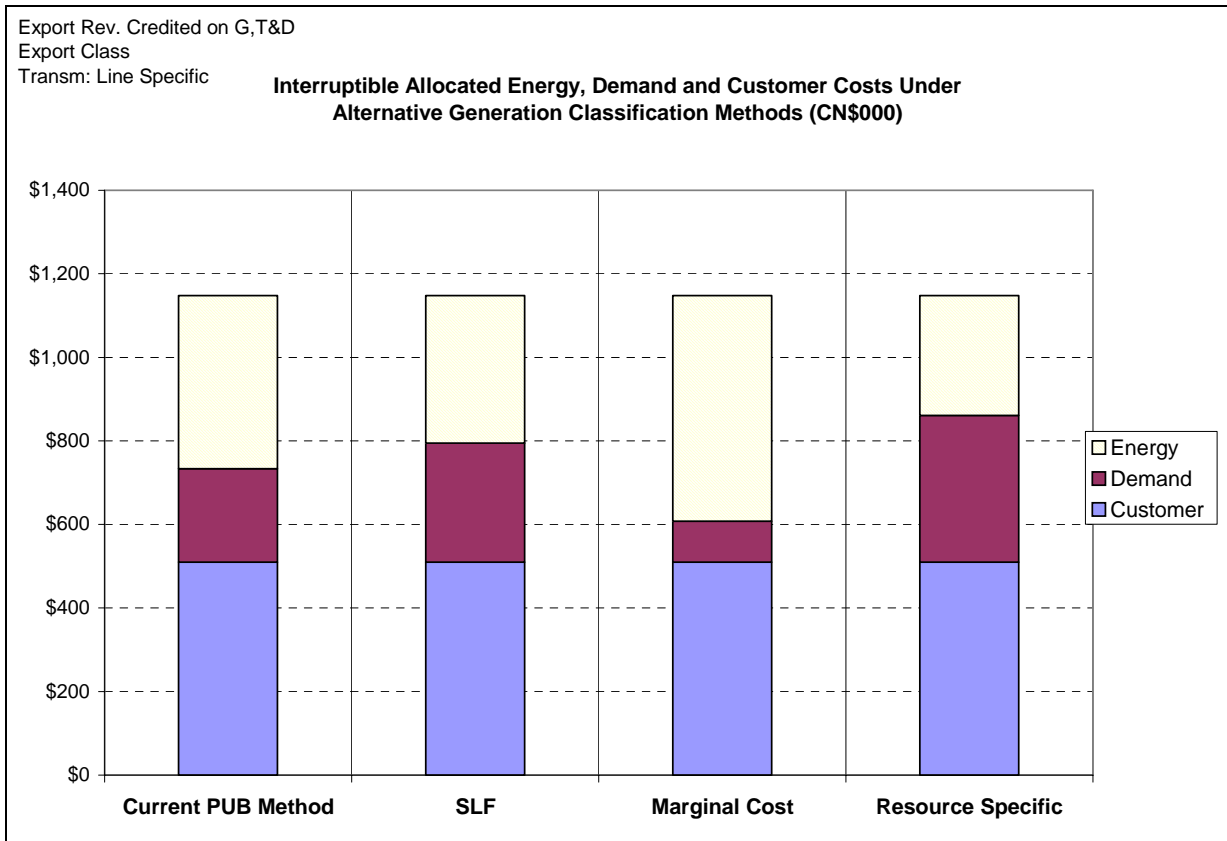
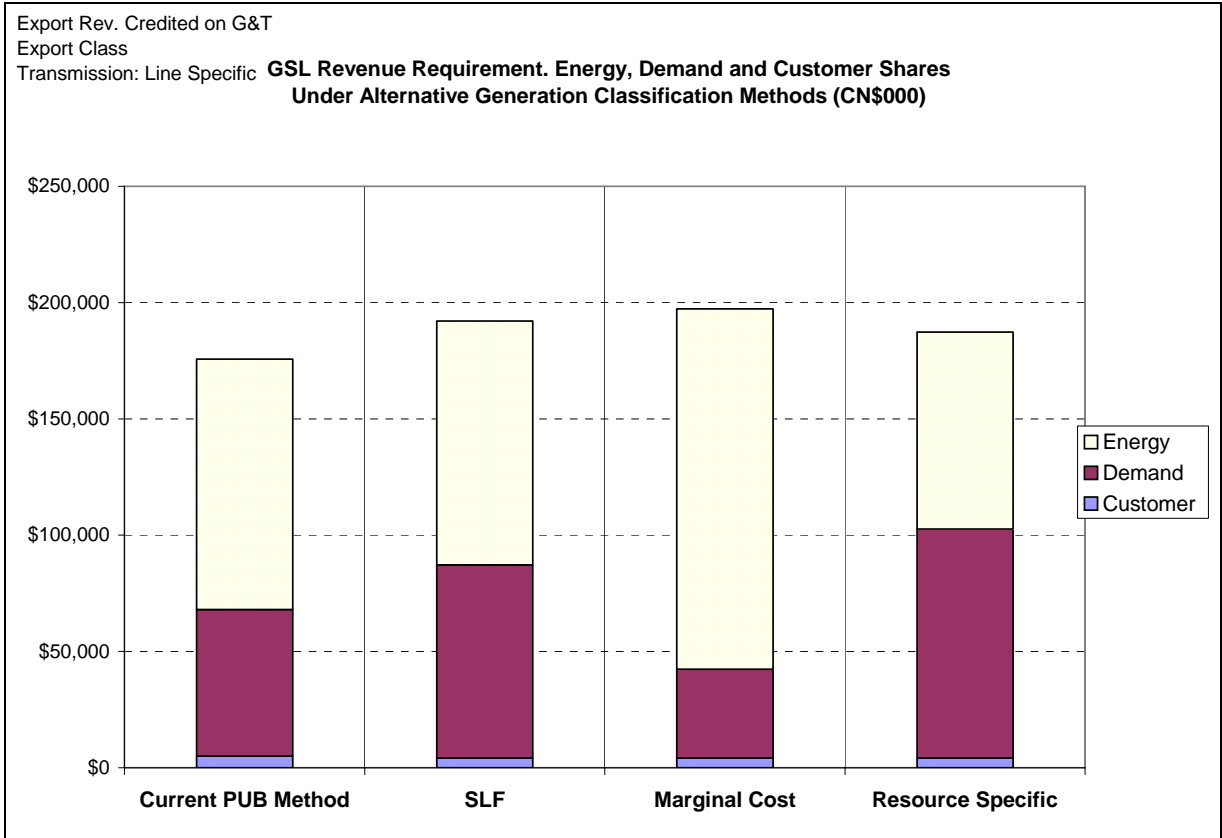
While choice of classification and allocation methods is critical for determining class revenue requirements, these choices also have implications for class rate structure if the results of the COS study are used for that purpose. Of course it is possible to use the COS study to determine total class revenues, and then use other information as the basis for rate structure. Many utilities use marginal cost information for this purpose. For example, allocated revenues from exports could be used to reduce the customer-related portion of residential and small commercial rates, leaving the per-kWh charges closer to efficient (marginal cost) levels.

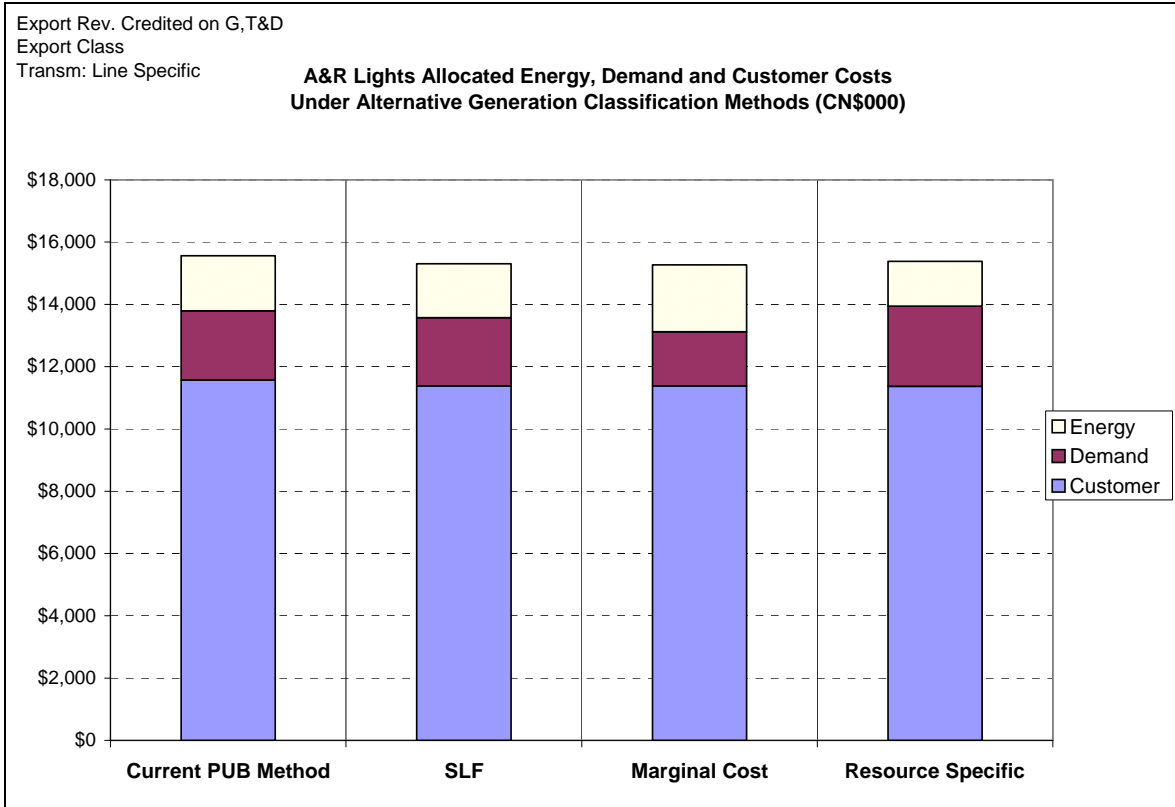
The charts below compare the shares of costs functionalized to customer, energy and demand for each major customer class under alternative sets of generation classification methods. In each case there is an export class, export revenues are allocated on the basis of G&T&D allocated costs, and transmission is classified using our preferred line-specific approach. The reduced customer-related share in all of these charts, relative to current methods, results from proportional crediting of net export revenues. Use of the marginal/opportunity cost method for generation classification increases the energy-related component and reduces the demand-related component, compared to other methods.



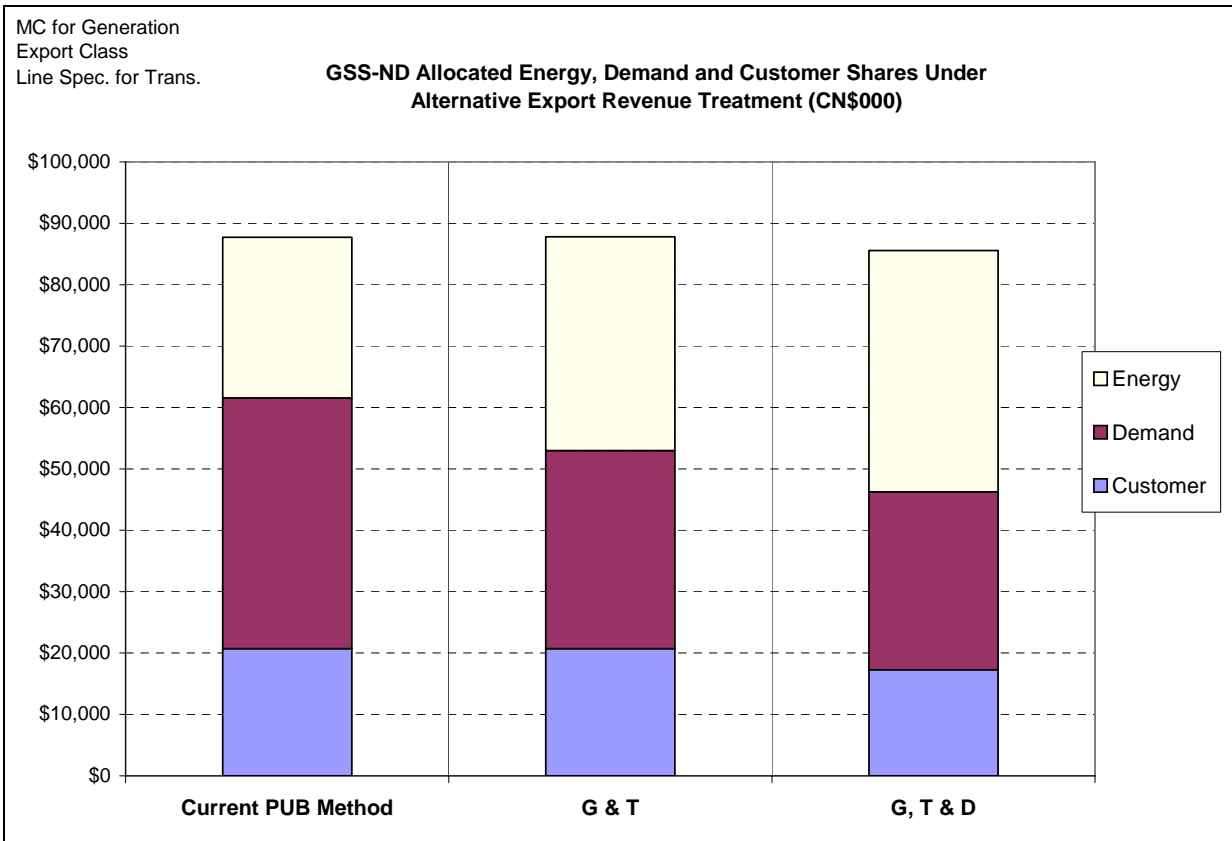
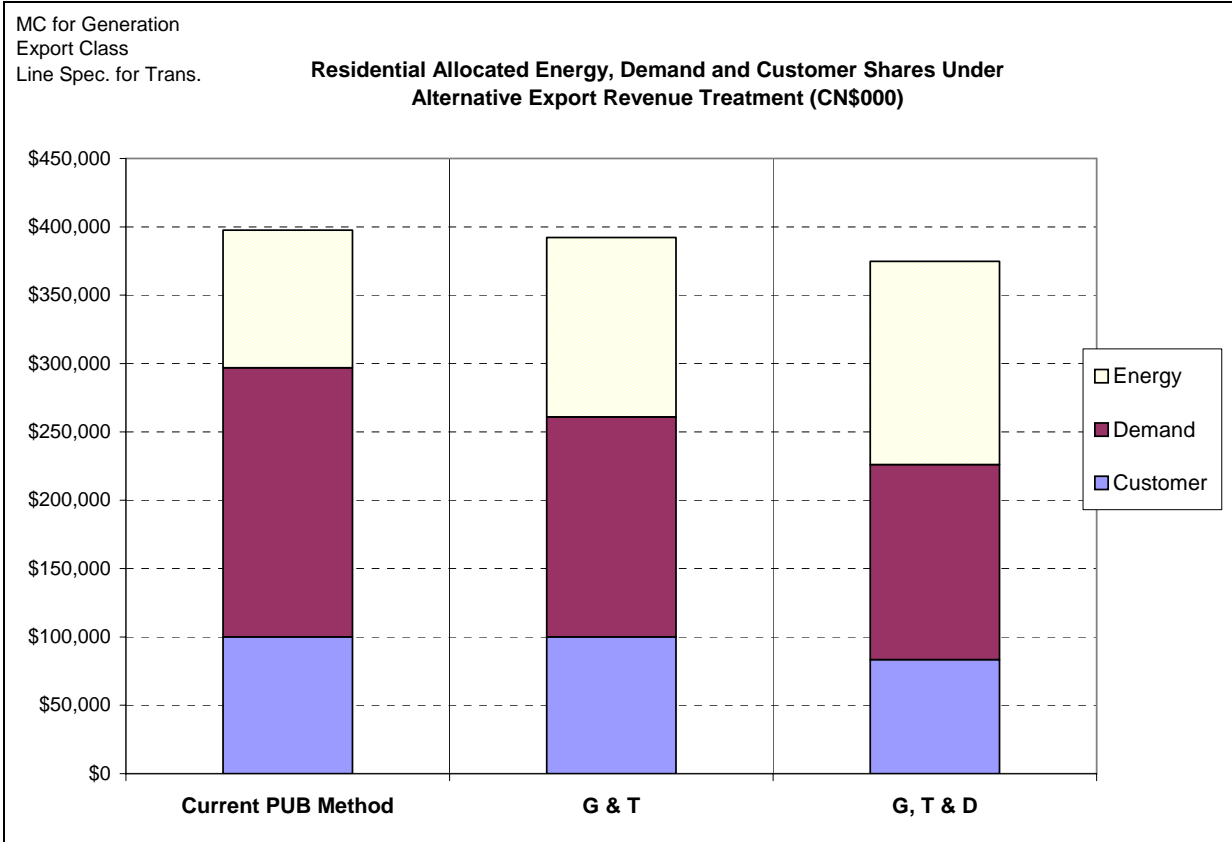


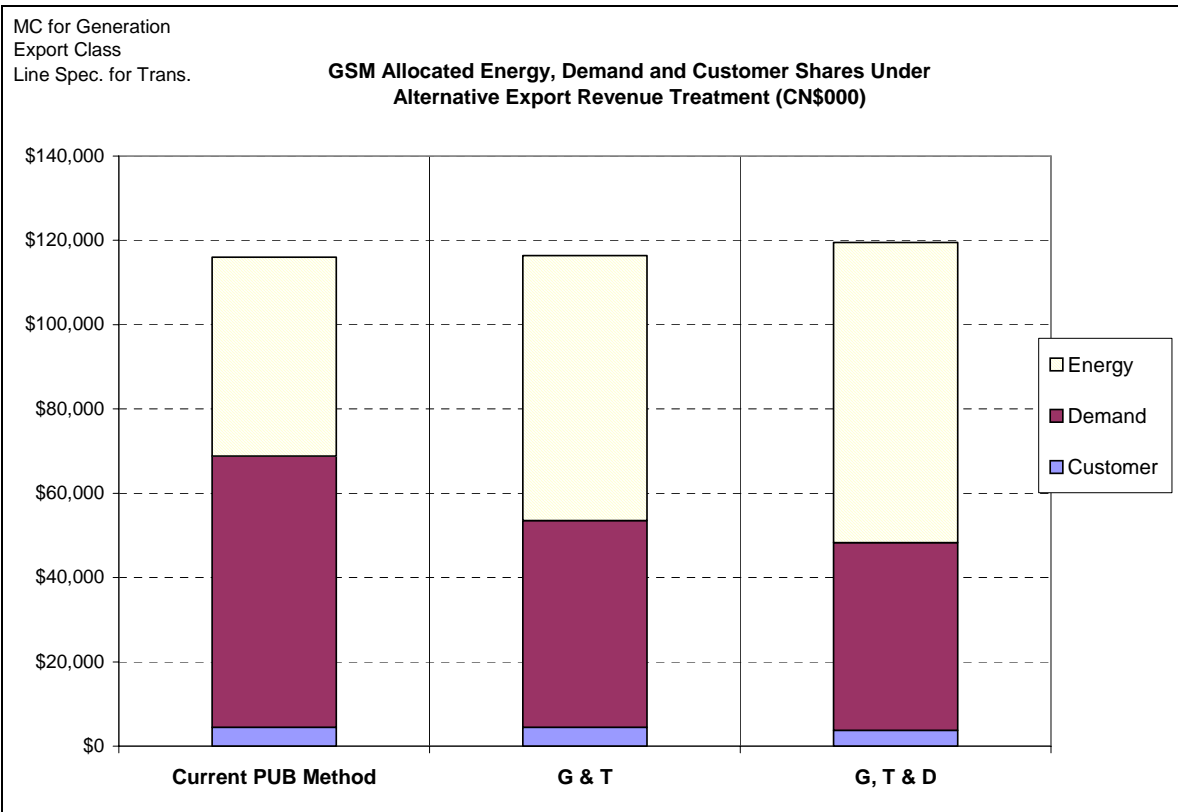
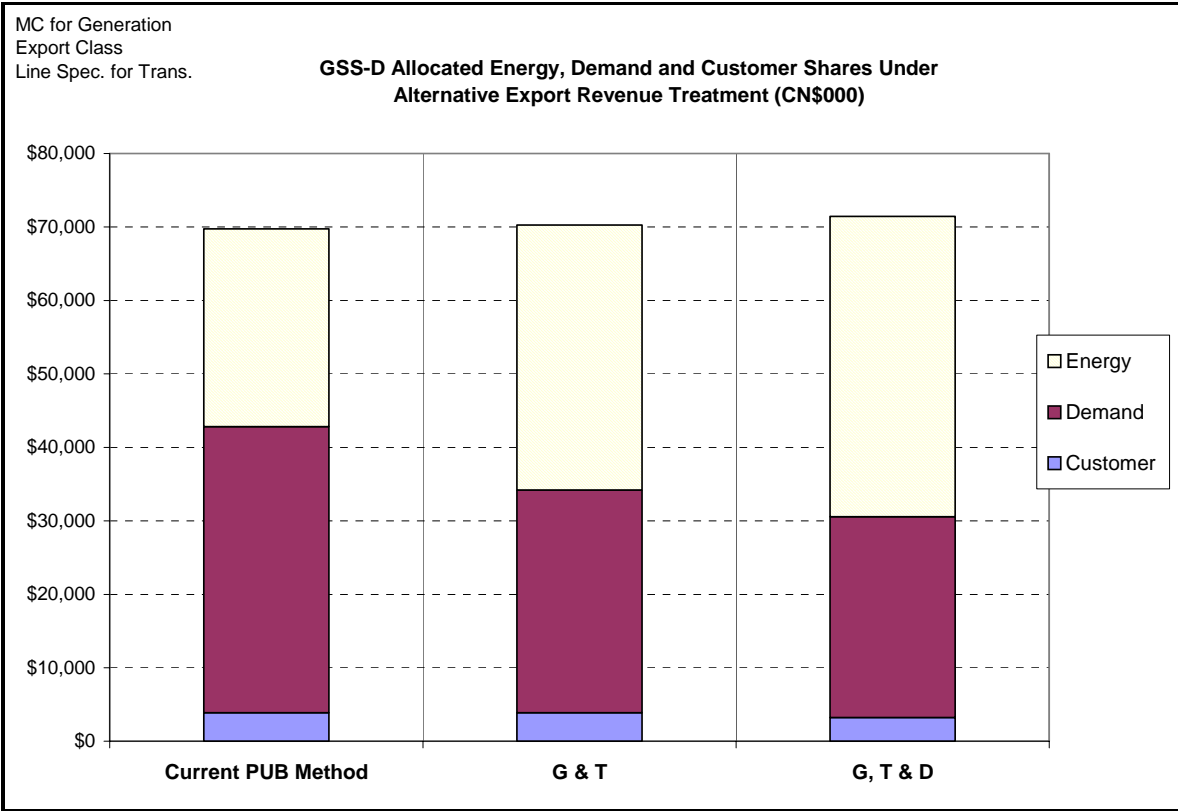


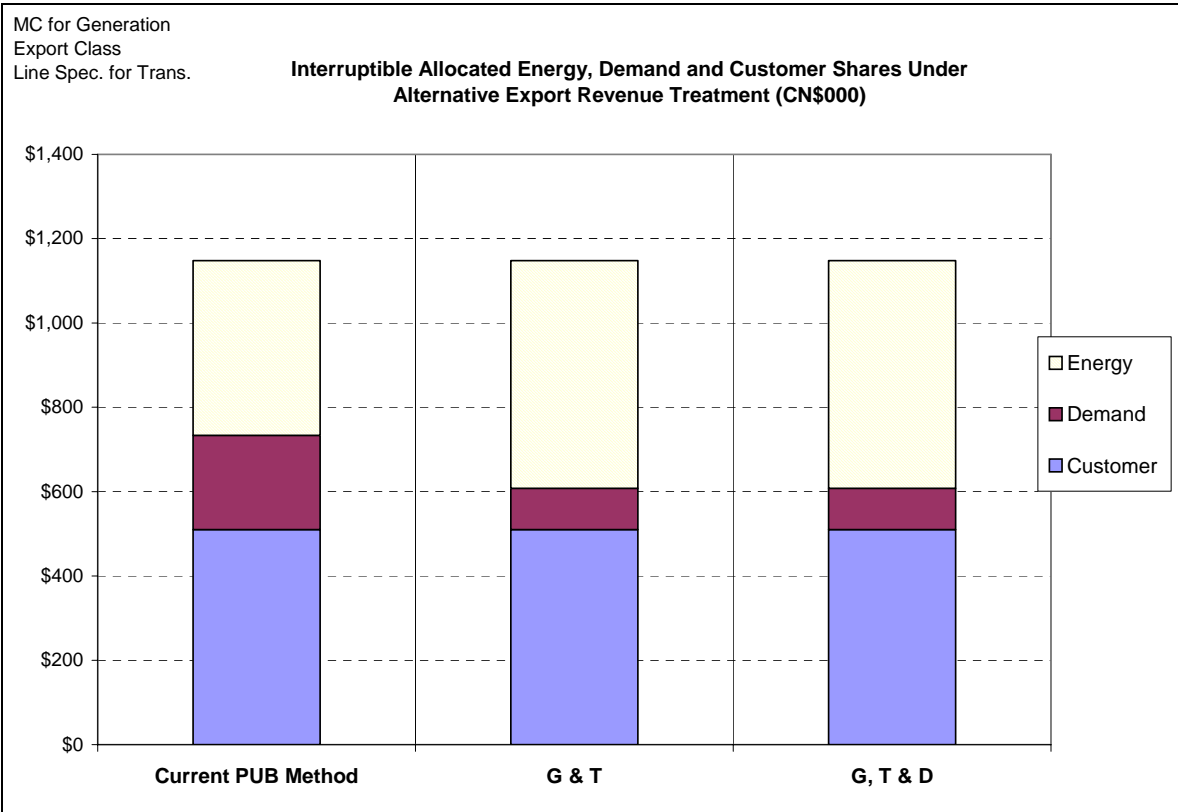
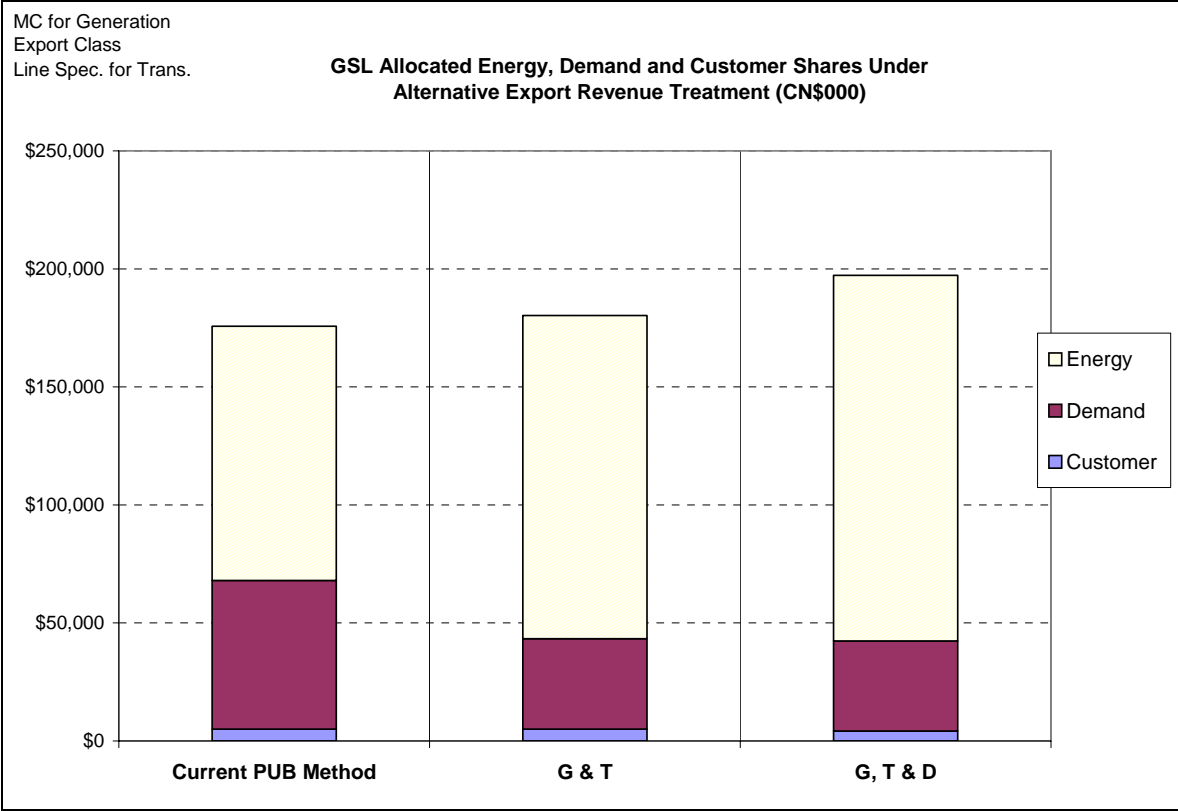


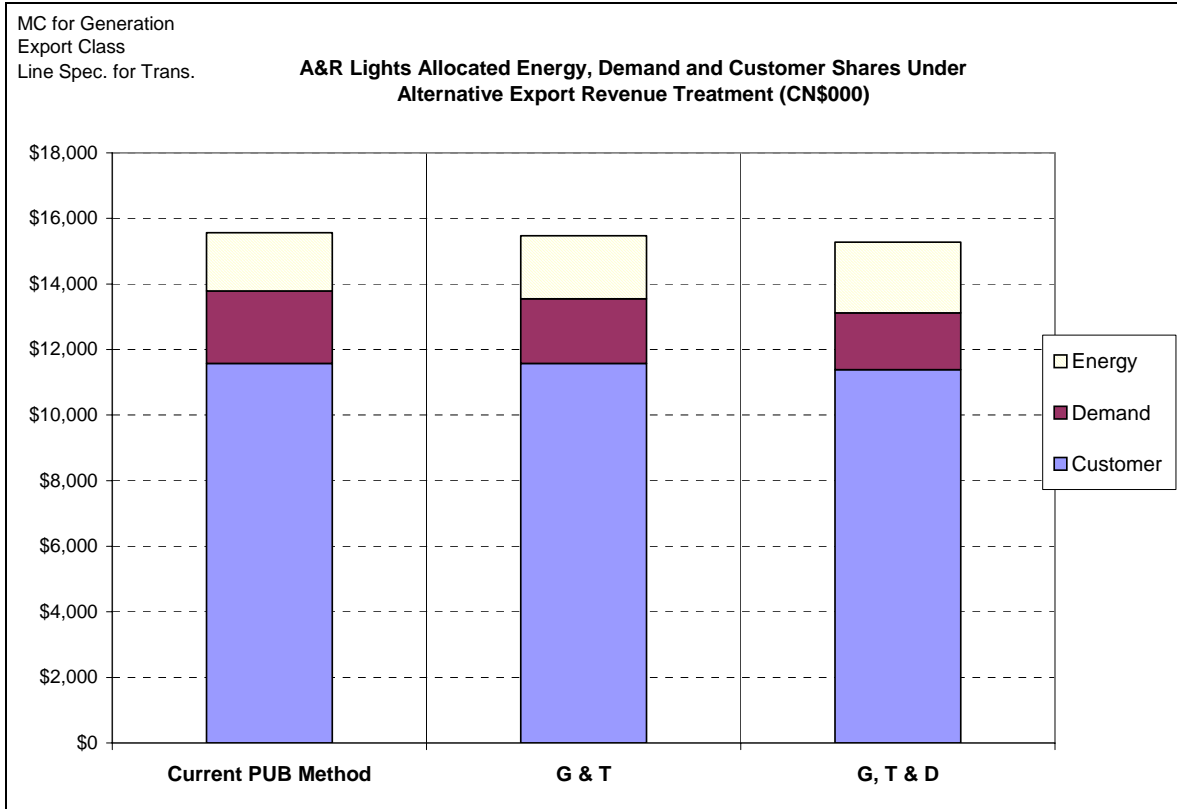


The charts below compare the shares of costs functionalized to customer, energy and demand for each major customer class under alternative sets of export revenue treatments. In each case there is an export class, generation costs are classified on the basis of marginal/opportunity costs, and transmission is classified using our preferred line-specific approach. The third bar in each chart shows our recommended approach – crediting net export revenues proportionally. The effect of this choice is to reduce the share of customer-related costs in the class revenue requirement and increase the energy-related share.







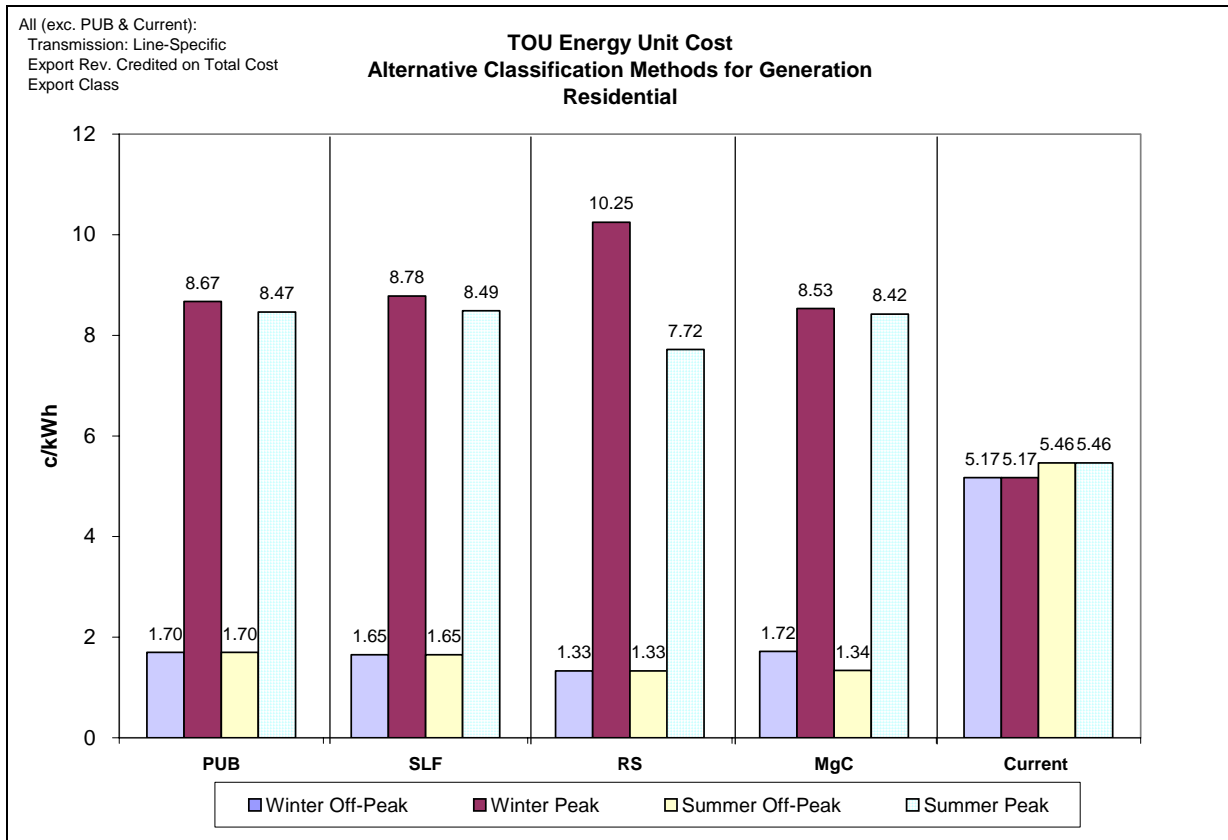


## H. Implications for Time-Differentiation of Rates

Choice of COS methods also has implications for the seasonality and peak/off-peak differentials in rates, if the time-differentiated embedded costs are used to design rates. Some of the generation methods tested for this report yield no differences in energy costs per kWh by period within season, and therefore provide no basis for time-differentiating recovery of energy-related costs across hours. Only the MC/Opportunity Cost and Resource Specific generation classification methods yield energy costs that differ by diurnal period.

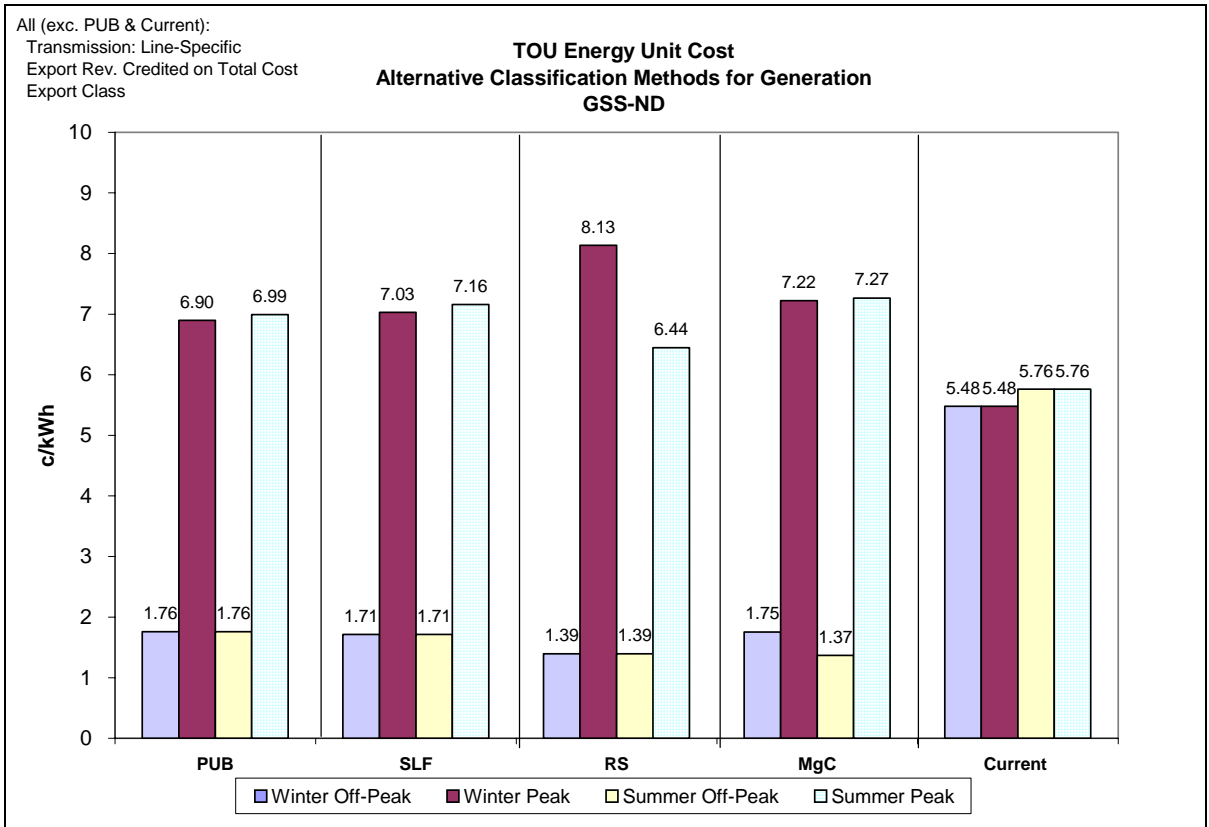
It is important to note that the assignment of costs to seasons and time-of-use periods is highly sensitive to the way a particular COS approach is implemented. For example, in the tests of the MC/opportunity cost approach for this report, there are large differences between peak and off-peak generation costs, but only small differences across seasons because the same market price estimate was used for both summer peak and winter peak periods. Use of a different measure of opportunity cost could change this pattern significantly. Therefore the unit costs from the COS tests shown below are illustrative, and the numerical results should not be used as a criterion for choosing one method over another.

The charts below illustrate the effect of choice of generation classification method<sup>50</sup> on per-kWh costs<sup>51</sup> of serving residential and small general service customers, compared to average per-kWh revenues under current, blocked tariffs. There are large peak/off-peak differentials in both summer and winter for these non-demand-metered customers under all of the methods, but the ratios vary from method to method. Current average per-kWh rates for these customers do not have diurnal differences. The seasonal differences are small, with all methods except Resource Specific showing slightly higher costs per kWh in the summer. This is consistent with the current rates.



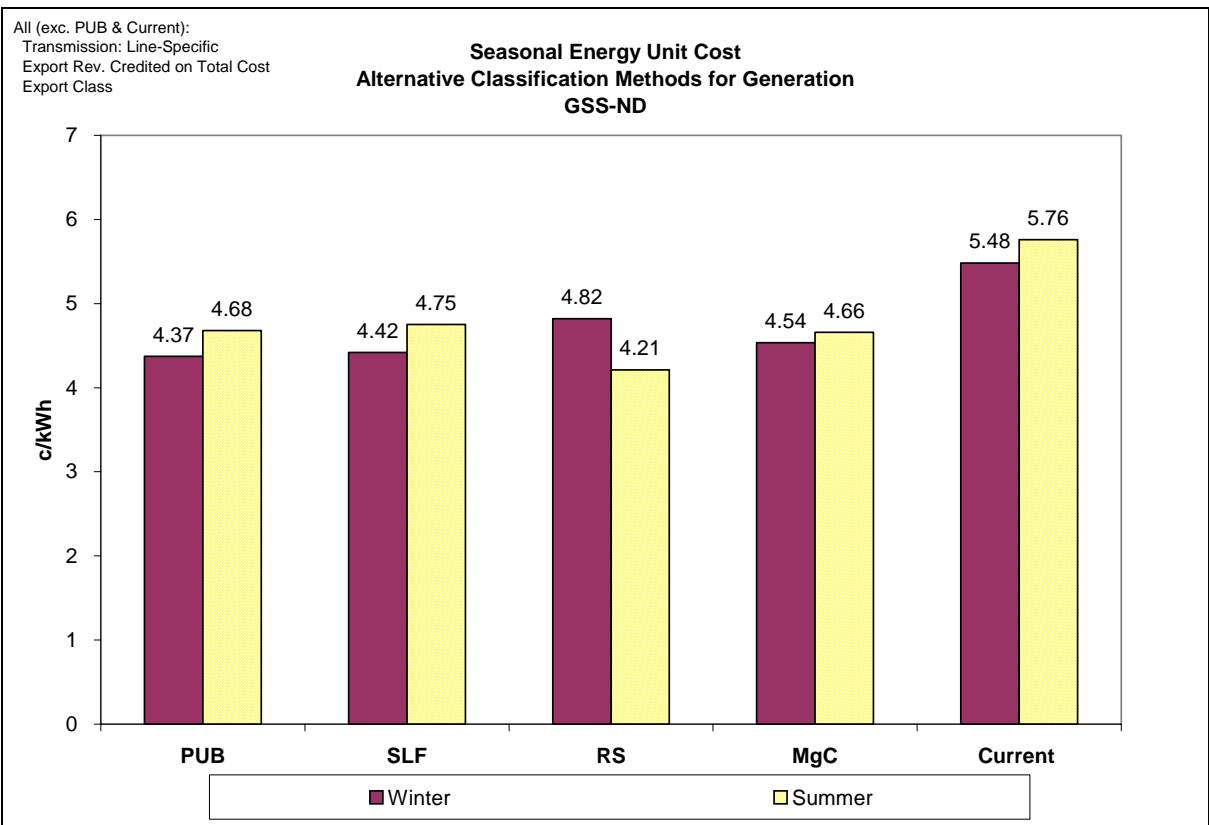
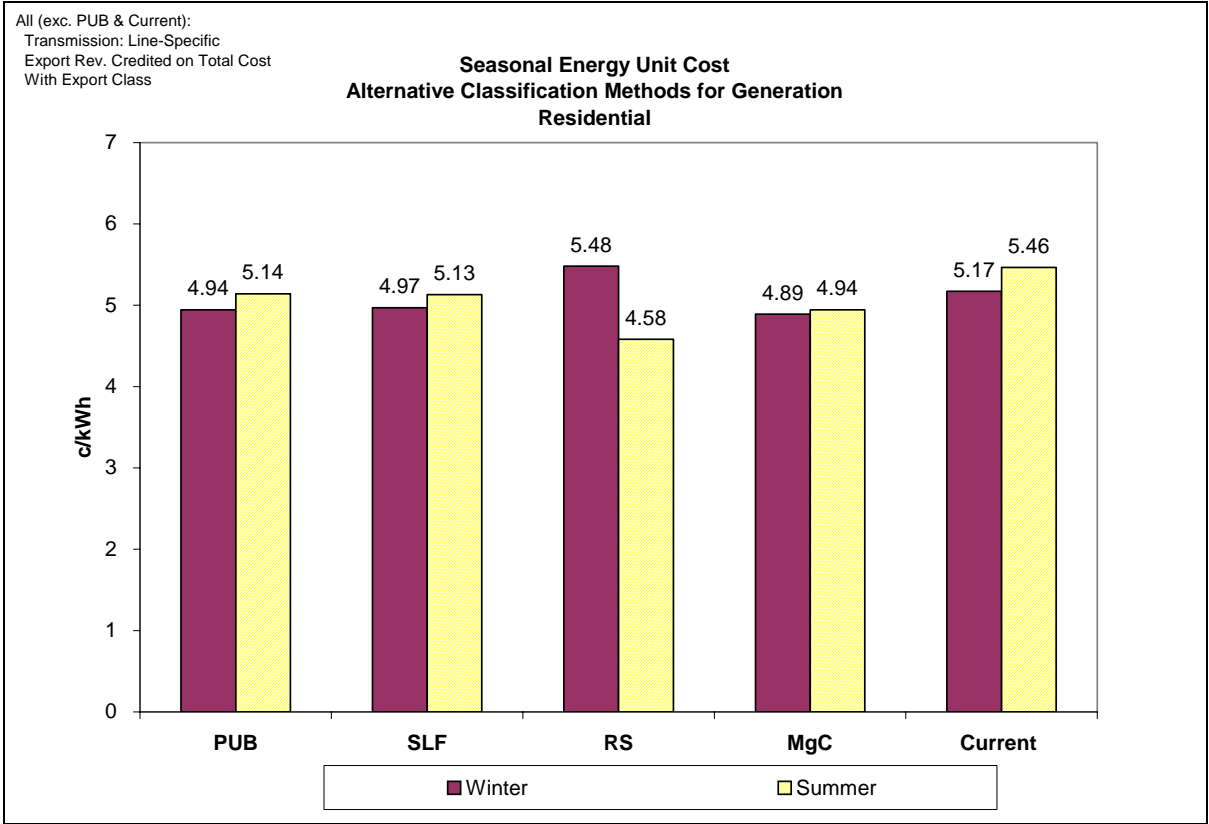
<sup>50</sup> These charts assume that transmission classification method is the ‘line-specific’, there is an export class, and export revenues are credited based on total allocated cost. Distribution and subtransmission costs, which are not addressed in this report, are assigned exclusively to the peak periods. We also analyzed the effects of classifying transmission as 100% demand-related compared to using the line-specific approach; the results were not significantly different.

<sup>51</sup> These costs include generation, transmission and demand-related distribution costs.

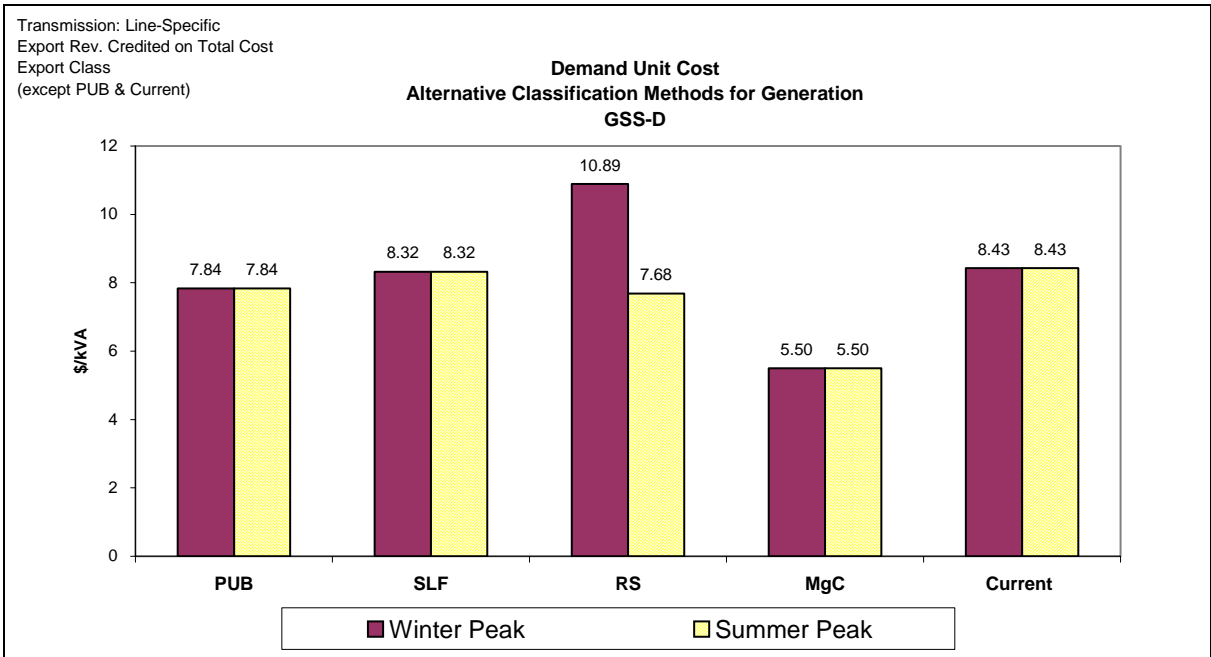
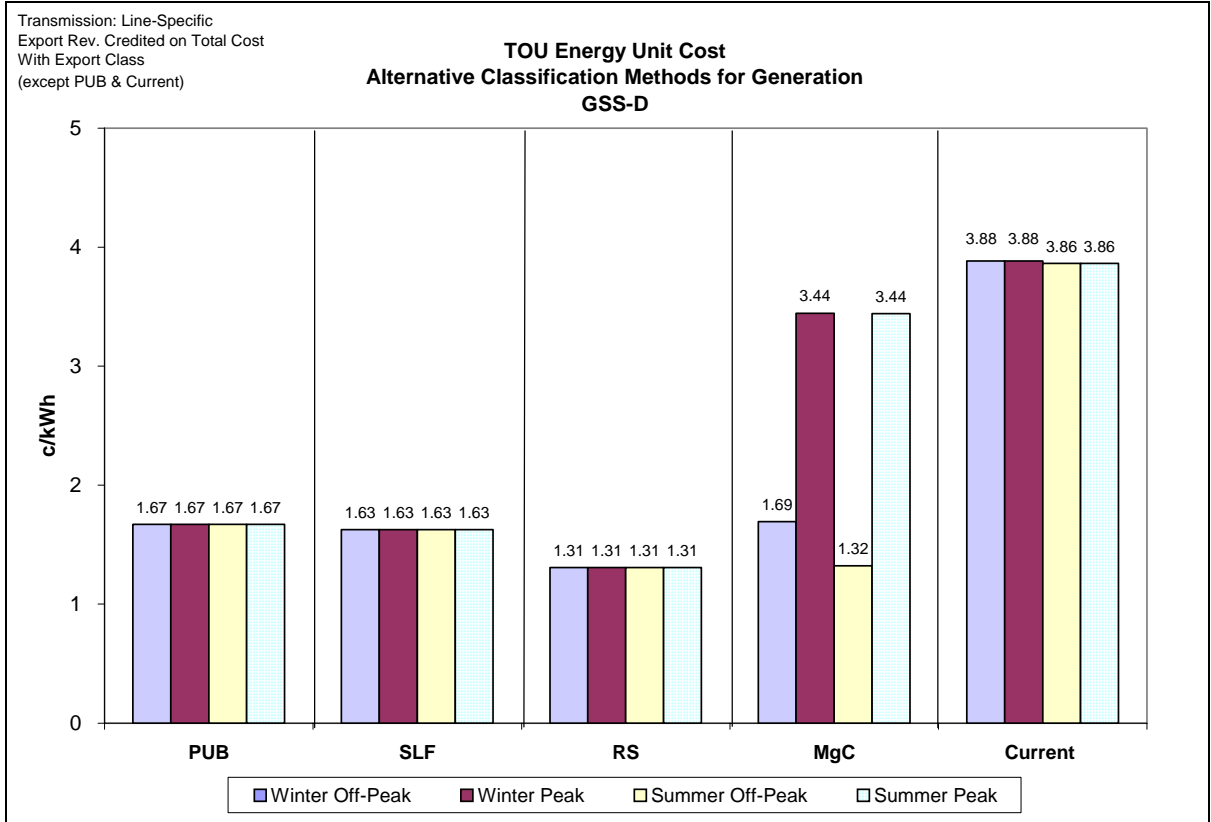


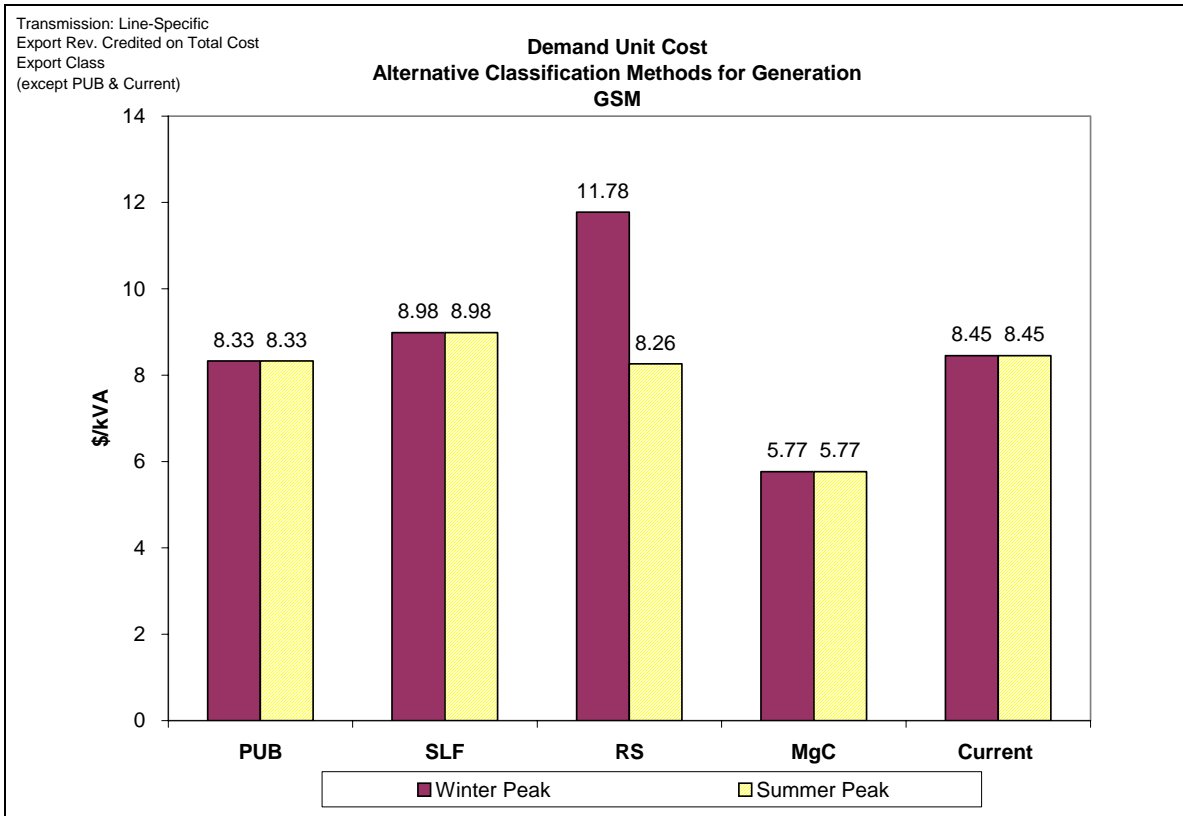
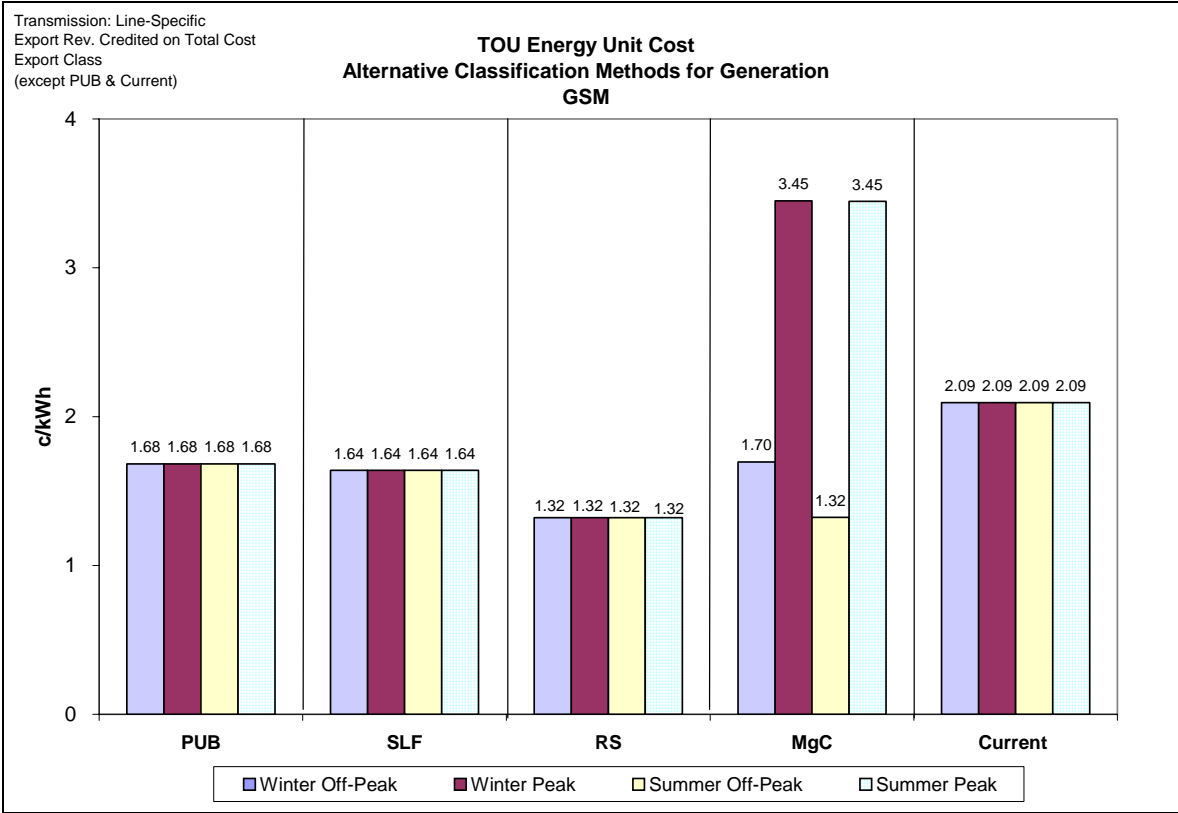
Since most residential and small general service customers are unlikely to have time-of-day meters, time-differentiation in their rates must be limited to seasonal differences. The two charts below show the levels of summer and winter average costs per kWh under the alternative generation classification methods. The seasonal differences are fairly small using the assumptions employed in the tests, with the largest differences occurring in the Resource-Specific test.

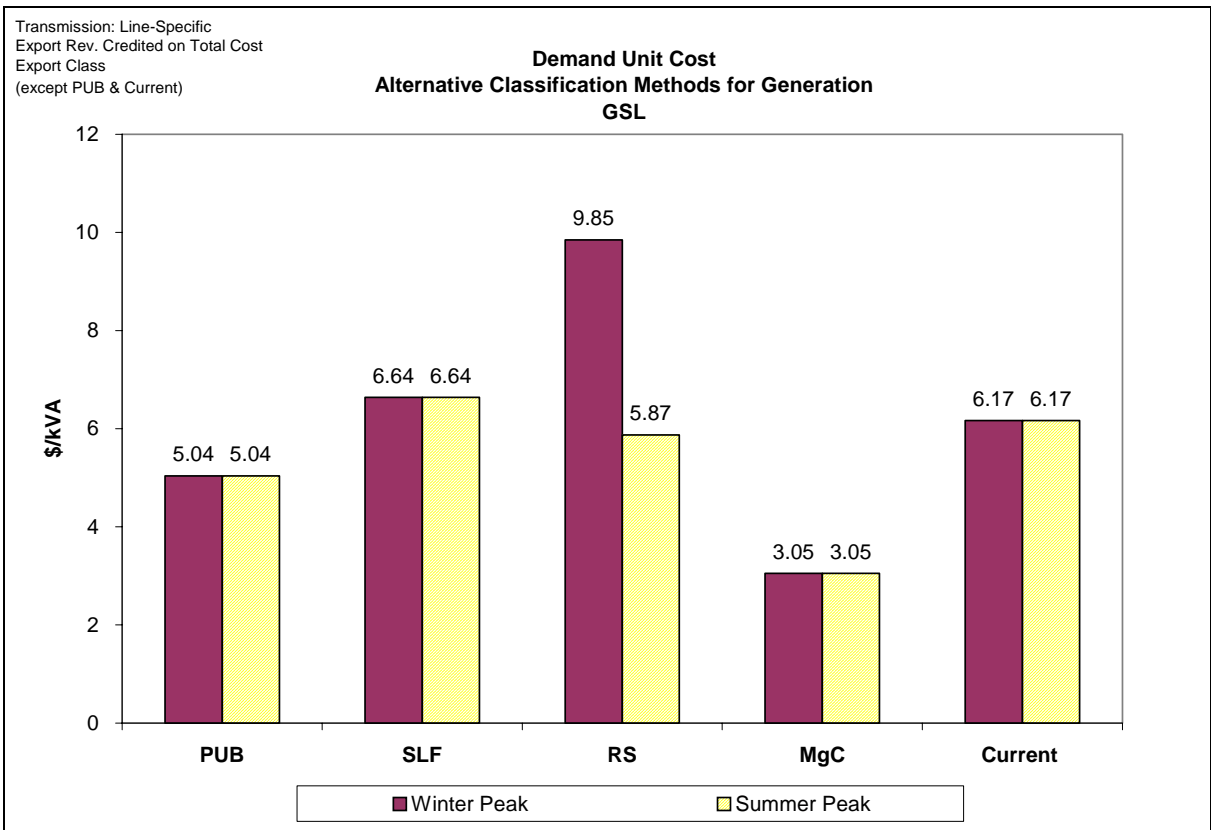
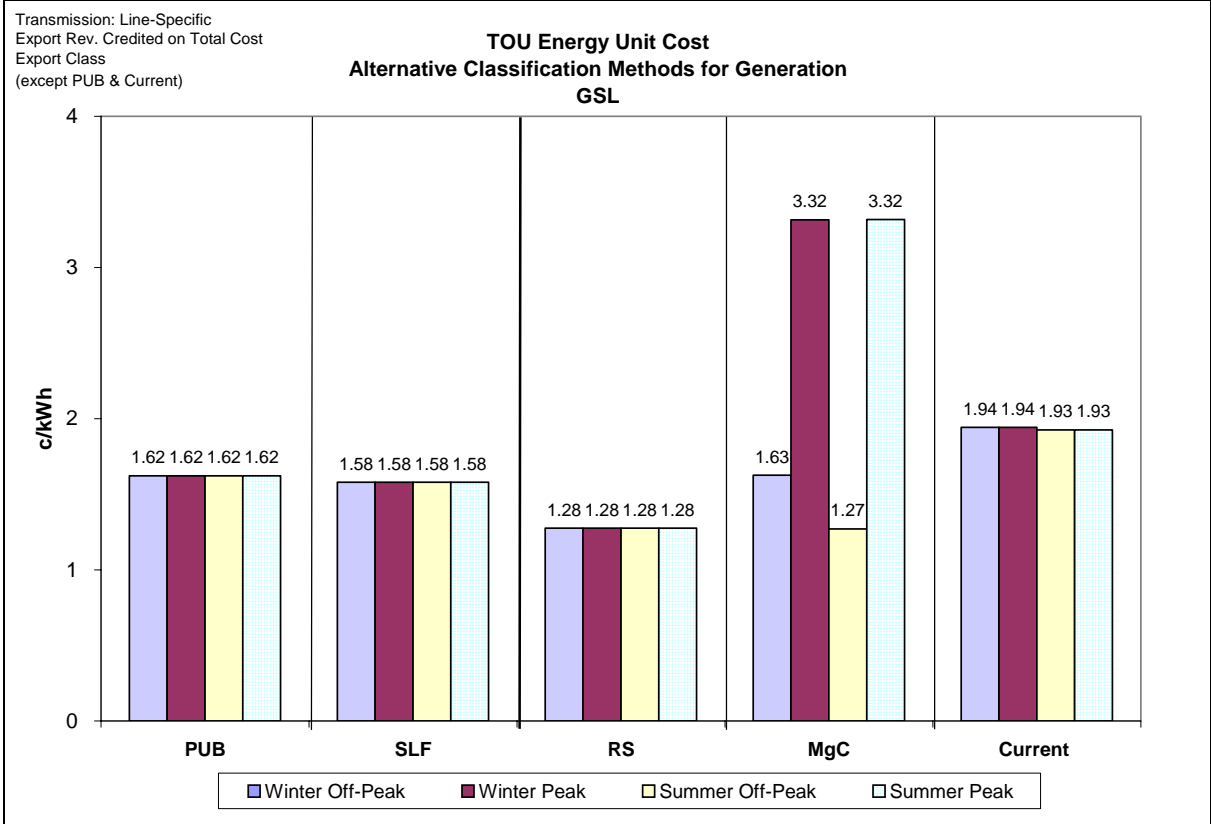




The implications of choice of COS methods for the demand-metered classes are much more significant. Below are two charts for each major customer class – one for energy costs and one for demand costs. All demand costs are assigned to the peak-period only.







As the charts above show, the PUB, SLF and RS generation classification methods provide no information about differences in per-kWh costs across periods and seasons. Only the MC method provides per-kWh signals that vary by time of day and season. The MC/Opportunity demand unit costs in these charts show no seasonal variation; however, this is a result of the lack of seasonality in the transmission and distribution costs, because there are no demand-related generation costs identified in the test of this method. The charts highlight the fact that if the COS study is used to design TOU rates, the MC/Opportunity Cost method is superior to the others tested.

### **VIII. SUMMARY OF RECOMMENDATIONS**

The rate objectives listed in Section III suggest that appropriate COS methods for Manitoba Hydro should:

- incorporate marginal or incremental cost elements;
- take competitive market conditions into account;
- treat large and variable export sales as a specific class; and
- allocate the above-cost revenues from export sales in a fair and minimally distorting way.

In addition, the methods need to be understandable, implementable, and appropriate as Manitoba Hydro's situation evolves. Our analysis suggests that the combination of methods that best accomplishes these tasks is the following:

- create an export class, and allocate costs to this class using the same allocation method used for domestic classes;
- credit the net revenues from exports in a minimally distorting way that fairly shares the benefits of the Province's hydro resources (e.g., in proportion to the domestic classes' total allocated costs:  $G+T+D$ );
- classify and time-differentiate generation costs using the pattern of Manitoba Hydro's opportunity costs, and refine the method used to estimate these opportunity costs;

- classify transmission costs using the line-specific approach and refine the method used to identify the energy- and demand-related nature of each line;
- allocate generation costs using class energy use (and demand in the 50 highest hours of the season if there is a separate seasonal opportunity cost of capacity)<sup>52</sup> by season and diurnal period;
- allocate demand-related transmission costs using class contribution to the highest 50 summer and 50 winter peaks;
- allocate energy-related transmission costs using annual class energy use;
- test the profitability of export sales by comparing incremental costs with incremental revenues, not using embedded costs or some combination of embedded and incremental costs.

Changing to these methods would result in significant shifts of revenue among classes and, if necessary, the changes could be phased in over several years. However, it is important to recognize that Manitoba Hydro's situation has changed dramatically over the past decade or so, and its rates must change to remain fair and cost-based. The dramatic differences in the allocations of benefits of exports among the classes under current methods (see chart in Section VII.A., page 32) highlight the need for change.

Adoption of the recommended changes could also have implications for the rate structure for individual classes. The recommended approach implies more emphasis on time-differentiated energy charges, and less emphasis on demand charges, relative to current COS methods. Of course the COS results used to determine class revenue allocations do not have to be used directly in rate structure. For example, we would recommend that, within a class, export revenue credits be used to reduce relatively fixed components of rates, leaving the important per-kWh charges closer to efficient (marginal cost) levels.

Methods based on the opportunity cost of generation (for both classification and time-differentiation purposes) are superior to other methods on efficiency grounds. Manitoba Hydro sells energy to the export market. As a result, export market prices represent Manitoba Hydro's

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<sup>52</sup> If a separate capacity price is available in more detailed periods, the demand allocator could be modified to correspond.

energy and capacity opportunity costs. Since market prices are differentiated on an hourly basis, the pattern of market prices provides valuable information and represents an objective measure for time-differentiation.

We understand that one of the obstacles to use of the marginal cost approach in the past was that Manitoba Hydro prefers not to reveal commercially-sensitive estimates of its marginal cost calculations. Therefore, we suggested using publicly-available independent forecasts (a consensus of market prices). Because this information was not readily available, Manitoba Hydro used recent market prices as a proxy for the pattern of its opportunity costs. This is a reasonable substitute until an acceptable forward-looking set of opportunity costs can be found.

The understandability of the recommended methods cannot be known until stakeholders have a chance to comment on them. However, we believe that our recommendations do meet the tests of being understandable, feasible, and suitable as Manitoba Hydro's situation evolves. In particular, changing patterns of opportunity costs and changing above-cost revenues from exports are specifically accommodated, as is the classification of any new transmission investment. These methods should stand Manitoba Hydro in good stead for many years to come.

**APPENDIX**

**Comparison of Class Allocations**

**Under Normal and Adverse**

**Hydro Conditions**



