SUBMISSION BY

THE CONSUMERS' ASSOCIATION OF CANADA,
SASKATCHEWAN BRANCH

TO

THE SASKATCHEWAN RATE REVIEW PANEL

IN THE MATTER OF

SASKPOWER'S COST OF SERVICE STUDY 2007/2008

July 30, 2008

#306 – 220 Third Avenue S, Saskatoon, SK, S7K 1M1
Tel. 306-242-4909, FAX 306-955-5810
Email: office.cacsk@sasktel.net
Website: www.consumersask.com

REVIEW OF SASKPOWER'S
COST OF SERVICE STUDY METHODOLOGY

PREPARED BY

BILL HARPER

ECONALYIS CONSULTING SERVICES

FOR

THE CONSUMERS' ASSOCIATION OF CANADA,

SASKATCHEWAN BRANCH

JULY 30, 2008

TABLE OF CONTENTS

1 Background and Purpose of Report

The Saskatchewan Rate Review Panel ("the Panel") serves as an advisory body to the Minister of the Crown Management Board and provides independent advice on rate applications from three Crown Corporations in Saskatchewan: SaskEnergy, SaskPower and SGI Auto Fund. The final decision about an Application and the Panel's recommendations rests with the Saskatchewan Government. The Panel's review process is typically triggered by a rate application from one of the three Crown Corporations which is then referred to the Panel by the Minister along with terms of reference.

On September 28th, 2006, the Minister referred to the Panel an Application by SaskPower for a rate increase of 4.3% effective January 1, 2007. The Application also included proposals for rate rebalancing between SaskPower's customer classes and a redesign of the rates charged to SaskPower's customers. On January 11, 2007 the Panel issued its Report to the Minister and one of its recommendations[1] called for an external review of SaskPower's Cost of Service methodology and Rate Design implementation before SaskPower's next Rate Application.

The external review was initiated later in 2007 and involved the preparation of an external review of SaskPower's costing and pricing methodologies by Foster Associates along with public consultations where both Foster Associates and SaskPower made presentations and stakeholders had an opportunity comment and ask questions. The process also provided for written questions by the Panel and other stakeholders and subsequent responses from Foster Associates and SaskPower. Final comments from interested parties are to be submitted to the Panel by July 30, 2008.

[1] Saskatchewan Rate Review Panel, Report to the Minister Regarding the January 2007 SaskPower Rate Application, page 2.

After reviewing the material provided by SaskPower, the report prepared by Foster Associates and attending the hearings in Saskatoon and Regina earlier this year, the Consumers' Association of Canada (Saskatchewan Branch) retained Econalysis Consulting Services (ECS), a Canadian consulting firm offering regulatory services to clients in the electricity and natural gas sectors, to provide a submission on the appropriateness of the SaskPower's current cost of service methodology and the related conclusions/recommendations prepared by Foster Associates.

The Submission was prepared by Bill Harper who, prior to joining ECS in July 2000, worked for over 25 years in the energy sector in Ontario, first with the Ontario Ministry of Energy and then, with Ontario Hydro and its successor company Hydro One. Mr. Harper's areas of expertise and experience include cost allocation/rate design, the regulation of electric distribution utilities and management of utility involvement in regulatory proceedings. He has served as an expert witness in public hearings before the Manitoba Public Utilities Board, the Ontario Energy Board and the Québec Régie de l'énergie on matters dealing with electric utility rates and regulation. He also assisted clients participating in the British Columbia Utility Commission's recent review of BC Hydro's Cost of Service study. A full copy of Mr. Harper's CV is attached in Appendix A.

The Submission starts by discussing the purpose of a Cost of Service study, the key steps involved and the principles (Section 2). The next three sections of the Submission consider, in turn, each of the three major steps involved in a Cost of Service study: Functionalization, Classification and Allocation. In each section there is a description of SaskPower's methodology and any related comments/recommendations by Fosters Associates followed by ECS's assessment as to the reasonableness of SaskPower's current practice. Section 6 then provides an overall summary of the ECS assessment.

2 Purpose of a Cost of Service Study

The Report from Foster Associates[2] notes that electric utility rates are generally designed to achieve a number of objectives. In the case of SaskPower these objectives are:

- Meeting revenue requirements
- Fairness and equity
- Economic efficiency
- Conservation of resources
- Simplicity & administrative ease; and
- Stability and gradualism

Overall, SaskPower's rate design objectives are consistent with those used by most electric utilities and reflect standard industry practice[3].

As indicated, one of the primary objectives in setting rates is that they should be "fair". In interpreting what is meant by "fair rates", one point on which there is a reasonable consensus is that fairness is achieved when customers pay what their service costs and there is an equal treatment of equals based on cost causation. In theory, no two customers are exactly the same. However, for practical purposes, customers who have similar characteristics in terms of electricity use are grouped into rate classes and rates are then set for each class.

As a guide for determining the appropriate rates to be charged to each class of customers (from a fairness perspective), gas and electric utilities generally perform an "embedded" cost of service or cost allocation study[4]. Such a Cost of Service study analyzes the components of the Company's costs and allocates or

[2] Review of SaskPower Costing and Pricing Methodologies, May 2008 ("the Foster Report"), pages 2-3
[3] Charles F. Philips Jr., The Regulation of Public Utilities, pages 410-411
[4] An embedded Cost of Service Study as undertaken by SaskPower attempts to establish the revenue requirement for each customer class based on accounting or embedded costs attributed to each customer class. Utilities can also undertake marginal cost of service studies which focus on determining the marginal costs of supplying each customer class. Such studies are typically employed when utilities are focusing on the objective of economic efficiency.

directly assigns plant investments and other assets as well as operating expenses among the various customer classes receiving service and, in some instances, among different services offered by the utility. The purpose of the study is to determine both the total and the unit costs of providing service to various customer classes. The results are then used to provide guidance in establishing the rate levels and designing the rate structures for each customer class so as to fairly apportion the total costs between customer classes and provide proper price signals. A cost of service study can also assist in identifying the costs of providing individual services in those jurisdictions where rates are to be unbundled.

Cost of Service studies generally employ a three-step process of cost analysis:

1) <u>Functionalization</u> of assets and annual expenses (including the cost of capital) according to the services (or functions) the utility provides such as production, transmission, distribution and customer service. However, these functions are frequently broken down further to capture specific activities.
2) <u>Classification</u> of each function's costs according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of three types: demand costs incurred to meet a customer's maximum instantaneous power requirements (i.e., demand or capacity); energy costs incurred to provide customers with electricity over a period of time; and, customer costs incurred to carry customers on the system.
3) <u>Allocation</u> of each functionalized and classified cost component to specific customer classes based on each class' contribution to the specific cost driver selected.

While the process appears straightforward and logical, the nature of utility operations is characterized by the existence of common or joint use facilities (and activities) that are used to support the provision of more than one product/service and/or serve more than one customer class. As a result, while cost analysts may strive to identify and isolate plant and expenses incurred exclusively to serve a specific customer class or group of customers, it is unrealistic to assume that large portions of a utility's plant investment and expenses can be directly assigned. In addition, there are practical constraints (e.g. time and budgets) that will limit the extent to which costs can be directly tracked and assigned.

In evaluating any Cost of Service study primary consideration is generally given to the need to reflect cost causality to the extent possible. In this regard, while industry standards and precedents have been established which can assist cost analysts in performing Cost of Service studies, recognition must also be given to the specific utility's circumstances (e.g., its operating characteristics and design). Other considerations include equity, efficiency, stability of results over time, transparency, logical consistency and practical limits of implementation.

Also, it should be noted that the concept of "cost causality" is sometimes not as straightforward as one would expect. It is generally accepted that customers not using a particular utility asset or service should not be held responsible for its costs. However, not all customers using an asset/service are necessarily equally responsible for the costs incurred. This issue is usually captured through the choice of the "cost driver" used in the classification and allocation phases of the Cost of Service study. However, debates sometimes arise as to whether:

a) Different rate classes are "equals" and, when they are not, how differences can be reflected in the cost of service methodology;
b) How "cost causation" should be determined and, in particular, whether all those utilizing an asset should bear some of the burden for cost responsibility.

As a final note, Cost of Service studies can be performed using either the forecast accounting data associated with a particular future test year's rate application or by using historical/actual accounting costs. For purposes of the Panel's current review, SaskPower provided and Foster Associates commented on a SaskPower Cost of Service study that used the Corporation's actual 2006 costs.

3 Cost of Service Study – Functionalization

3.1 SaskPower's Practice

3.1.1 Functions Employed

The "costs" that are functionalized included rate base, expenses, annual return and non-rate revenues consistent with SaskPower's 2006 Annual Report[5]. The functions employed by SaskPower are:

- Generation
- Transmission
- Distribution
- Customer Service.

Then, in order to further facilitate the allocation of costs to customer classes, the costs assigned to each function are further assigned to sub-functions. The following extract[6] for SaskPower's 2006 COSS sets out the sub-functions used.

Generation	**Distribution**
Load	Area Substations
Losses	Distribution Mains
Scheduling & Dispatch	Urban Laterals
Regulation & Frequency Response	Rural Laterals
Spinning Reserve	Transformers
Supplementary Reserve	Services Customer
Planning Reserve	Customer Contributions
Reactive Supply	Meters
Grants in Lieu of Taxes	Streetlights
Interruptible Adjustment	
Transmission	**Customer Service**
Main Grid	Metering Services
138kV Lines Radials	Meter Reading
138/72kV Substations	Billing & Customer Accounts
72kV Lines Radials	Customer Collections
	Customer Service
	Marketing

[5] SaskPower, 2006 Embedded Cost of Service Study ("SaskPower 2006 COSS"), pages 7-8
[6] SaskPower 2006 COSS, page 9

3.1.2 Assignment of Costs to Functions/Sub-Functions

Rate Base Items

- ♣ Generation, Transmission and Distribution Plant In-Service

Generation, Transmission and Distribution (including Meters) plant are designated as such in SaskPower's accounting records and the plant in-service costs and accumulated depreciation are generally assigned to the corresponding function. There are two exceptions[7]:

- The portion of transmission assets associated with distribution sub-stations is re-assigned to the Distribution function, and
- A small portion of transmission assets is also reassigned to Generation function.

Within the Generation function, the assets (and costs) associated with providing each of the Ancillary services[8] are identified and assigned to the corresponding sub-function. The balance of the Generation production plant costs are assigned to the Load and Losses sub-functions.

Within the Transmission and Distribution functions, the plant costs are assigned to the sub-functions based on the nature of the assets.

- ♣ General Plant

General Plant includes assets such as Unused Land; Buildings; Office Furniture/Equipment; Vehicles & Equipment; Computer Development and Equipment; Communications, Protection and Control Equipment; and Tools & Equipment.

[7] SaskPower 2006 COSS, page 10
[8] Foster Response to Panel Question #12. See SaskPower Response to Saskatoon Light & Power Question #1.2 for a definition of each Ancillary Service.

The assignment of these costs to functions is based on internal information regarding the usage of the assets and/or a related cost driver[9]. Within each function, the costs are pro-rated to sub-functions using operations, maintenance and administration expense.

- Contributions in Aid & Reconstruction (CIA&R)

Accounting records are such that the unamortized CIA&R balances can be readily assigned to transmission and distribution (and the related sub-functions).

- Allowance for Working Capital

The Corporation's allowance for Working Capital is calculated as 12.5% of operations, maintenance and administration expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense. It is pro-rated to functions and sub-functions based on the assignment of these expense items.

- Inventories

The Corporation's accounting records track inventory costs by Power Production, Transmission and Distribution. This permits the costs to be directly assigned to the related functions. The costs are then pro-rated to sub-functions using operations, maintenance and administration expense.

- Other Assets

For purposes of functionalization[10], Other Assets are separated into four categories:

[9] SaskPower 2006 COSS, page 11
[10] SaskPower 2006 COSS, page 12

- Natural Gas and Coal related – which are functionalized to Generation.
- Employee related (such as deferred pension costs) – which are functionalized using head count by business unit.
- Insurance related – which are functionalized based on the purpose of the insurance[11].
- Miscellaneous Other Assets – which are functionalized using operations, maintenance and administration expense.

♣ SaskPower's Coal Reserves

These are functionalized as Generation and assigned to the Load and Losses sub-functions.

♣ Subsidiary Investments

Both SaskPower International's Cory Cogeneration and Wind Power investments along with Shand Greenhouse's assets are assigned to the Generation function[12].

Revenue Requirement/Expense Items

♣ Fuel Expense/Purchased Power/Export & Net Trading Revenue

These items are all assigned to the Generation function. The majority of the costs (revenues) are assigned to the Load and Losses sub-functions. However, a small amount is attributed to the Ancillary Service – Reactive Supply[13].

[11] Foster Report, page 46
[12] SaskPower International's investment in the MRM Cogeneration Station in Alberta is not included in the 2006 Cost of Service Study (SaskPower 2006 COSS, page 2)
[13] SaskPower 2006 COSS, page 34

- OM&A Costs – Core Activities

The OM&A costs associated with the Power Production business unit, SaskPower International's Cory Cogeneration Plant, Shand Greenhouse and NorthPoint Energy Solutions[14] are all assigned to the Generation function.

Virtually all of the OM&A costs for the Transmission and Distribution business unit are assigned to the Transmission and Distribution functions using SaskPower's internal cost reports. The exception is a small amount of OM&A related to transmission planning, scheduling & dispatch and generation regulation and frequency response which is functionalized to generation. The later is done to be consistent with the treatment of Ancillary Services.

Transmission OM&A is separated into Line versus Station expenses and then the Line expenses are sub-functionalized using the line length by sub-function. Station expense is sub-functionalized using the station asset plant in service by sub-function[15].

Distribution OM&A is assigned to the Distribution and Customer Service functions and sub-functions using a combination of internal cost reports and staff advice.

Customer Service business unit OM&A is assigned to the Customer Service function and sub-functionalized using internal cost reports. Lastly, bad debt expense is assigned to the customer collections sub-function

[14] NorthPoint has an agreement with SaskPower to perform generation and load management services, provide electricity export and import functions related to SaskPower generation assets, manage SaskPower's natural gas supplies and act as a principal in wholesale trading that does not involve generation assets of SaskPower (SaskPower 2006 COSS, page 2).
[15] SaskPower 2006 COSS, page 13

♣ OM&A Costs – Support Activities

As well as the three core business units (Power Production, Transmission & Distribution and Customer Services), SaskPower's organizational structure includes various support groups. The costs associated with a number of these support groups are assigned to functions and sub-functions based on the sum of the assigned cost from the three line business units[16]. However, for the other support groups more appropriate allocation factors are developed[17]:

- OM&A associated with insurance premiums and insurable losses is functionalized based on advice from the Risk Management and Insurance Department.
- Other Corporate and Financial Services OM&A is functionalized based on employee head count by business unit and support group.
- Human Resource support costs are functionalized based on the head count by business unit and then OM&A is used to sub-functionalize.
- Corporate Information and Technology support costs are separated into personal computer-related and Business Unit-related. The former is functionalized using employee head count; while the latter is functionalized using internal cost reports. Again, the sub-functionalization is done using OM&A as the allocation factor.
- Planning and Regulatory Affairs costs are assigned to functions and sub-functions based on the sum of the assigned costs for the three line Business Units and the Support Groups.
- Environment costs are assigned to functions based on an analysis done by the Environment department staff. Again, the sub-functionalization is done using OM&A as the allocation factor.

[16] The Groups treated in this manner include President/Board; General Counsel & Land; and Communications and Public Affairs/
[17] See also Foster Report, page 47

♣ Corporate Capital Tax

Corporate capital tax is pro-rated to functions and sub-functions based on the plant in-service less accumulated depreciation less the unamortized balance of CIA&R assigned to each.

♣ Depreciation Expense

The functionalization and sub-functionalization of depreciation expense and amortization of CIA&R follow the assignment of Plant In-Service and Unamortized CIA&R respectively.

♣ Grants in Lieu of Taxes

Grants in lieu of taxes are assigned to the Generation function and maintained in a separate sub-function.

♣ Miscellaneous Tax

Miscellaneous taxes are grouped into three categories:

- Taxes associated with power production and fuel supply which are functionalized to Generation.
- Taxes associated with gas & electric inspections which are functionalized to Customer Service.
- Taxes associated with buildings which are functionalized in the same manner as Building plant.

♣ Return on Rate Base

Return on rate base is functionalized based on the overall functionalization of the various rate base components, as described above.

Other Income and Revenues

Other income and revenues are treated as an offset to the revenue requirement. The various sources of other income/revenues are treated in the Cost of Service study as follows[18]:

- Customer service payment charges are assigned to the billing, customer accounts and customer collections sub-functions.
- Meter reading income is assigned to the meter reading sub-function
- Gas & Electric inspections income is assigned to the customer services sub-function.
- Transmission-related income is assigned to sub-functions within Generation (i.e., Ancillary Services) and Transmission. For the later, the revenues are allocated to sub-functions using transmission OM&A.
- Distribution-related income is assigned to sub-functions within the Distribution function using Distribution OM&A expense.
- The Green power premium and revenues for NorthPoint and SaskPower International's fly ash sales are all functionalized as Generation and sub-functionalized to Load and Losses.

3.2 Foster's Comments and Recommendations

Foster's terms of engagement did not specifically request a review of SaskPower's functionalization process in terms of generation, transmission and distribution. However, a cursory review by Foster did not identify the need for any changes at the present time. Foster was requested to review the functionalization of Corporate Overhead and concluded that SaskPower's current approach reasonably conforms to benchmark practices[19].

---

[18] SaskPower 2006 COSS, page 16
[19] Foster Report, page 61

3.3 ECS Comments

Functions Employed

The functions, and indeed the sub-functions, employed by SaskPower are generally consistent with those used by other electric utilities. This observation is also supported by the Foster Report's benchmark review of functionalization practices[20]. Furthermore, the adoption of sub-functions to separately track the costs of Ancillary services and Distribution Sub-Stations effectively addresses the boundary issues between: a) Generation versus Transmission and b) Transmission versus Distribution respectively. In ECS's view, the functions and sub-functions employed by SaskPower are generally reasonable.

However, there are two issues worth noting. The first is SaskPower's distinctive use of sub-functions for Load and Losses. The materials provided do not fully explain the rationale for making this distinction, nor how the generation-related costs are assigned between the two sub-functions. Typically the issue of losses and the impact they have on the need for generation, transmission and distribution facilities is addressed by including the appropriate losses in the demand and energy allocation factors for each customer class. ECS notes that SaskPower acknowledges this issue in its responses to the June 30th 2008 questions[21].

The second is SaskPower's segregation of the CIA&R (both rate base and amortization) associated with customer services and streetlights into a separate Distribution sub-function. SaskPower's reason for doing this is so that the costs can be allocated to the customer class from which the contribution was made[22]. Typically the purpose of capital contributions is to hold other customers harmless in instances where customers are seeking new connections/upgrades to service

[20] Foster Report, pages 8-11.
[21] SaskPower's Response to CAPP #3.2
[22] Foster Report, page 49 and SaskPower 2006 COSS, page 67

beyond what is generally provided through rates. Under such a paradigm, the unamortized capital contributions and the annual amortization should be assigned to the sub-functions representing the assets which the contributions were meant to help underwrite. Further explanation is required by SaskPower to support its current practice.

Cost Functionalization – Rate Base

SaskPower's assignment of rate base related costs to functions and sub-functions appears reasonable. However, there are a couple of instances where it is not clear as to the methodology used and/or the rationale:

- In the case of Transmission plant, a small portion was re-assigned to Generation. However, no explanation is provided for the rationale of this reassignment.
- No explanation is provided on why the costs associated with Shand Greenhouse are assigned to Generation. One rationale could be that the growth and distribution of tree seedlings is viewed as an activity that will provide a GHG offset to fossil generation.
- No explanation is provided on how the split between urban versus rural primary laterals is determined.

Cost Functionalization – Expense and Income Items

In general SaskPower's functionalization of the various expenses and revenue items that make up its revenue requirement is appropriate. However, there are instances where it is not clear that the appropriate assignments have been made:

- As was the case with the Transmission assets, no rationale is provided for reassigning a portion of Transmission Planning OM&A to Generation.

- There is no explanation on why Grants in Lieu of Taxes are assigned to the Generation function. According to SaskPower's 2007 Rate Application[23], these payments are made to 13 cities based on electricity revenues from customers in those areas. This would suggest that these Grants in Lieu of Taxes are not a Generation-related cost but rather an overall cost of doing business in those areas. However, since the related costs are isolated in a separate sub-function the nature of the costs can be addressed in the classification and allocation stages of the Study.
- In SaskPower's 2007 Rate Application a reference[24] was made to DSM programs being offered in 2006. These costs are not separated out for purposes of the Cost of Service study. Rather, it appears that they are included in the reported costs for one of SaskPower's Business Units and processed through the Cost of Service study in the same manner as the Unit's other costs. If, as the 2007 Rate Application suggests[25], the purpose behind DSM spending is to reduce the need for future generation additions then DSM spending should be functionalized as Generation[26].

None of the issues identified above are sufficiently substantive[27] to require a change to the Cost of Service methodology at this time. However, in the interest of transparency, they should addressed by SaskPower as part of its next Rate Application.

[23] Page 34
[24] Page 25
[25] Pages 24-25
[26] If DSM spending is also justified on the basis of avoided Transmission or Distribution investment then it would be appropriate to assign a portion of the costs to these functions as well.
[27] Reading of SaskPower's 2007 Rate Application suggests that current spending levels on DSM are relatively small but are expected to grow in the future.

4 Cost of Service Study – Classification

4.1 Generation

4.1.1 SaskPower's Practice

The rate base and revenue requirement costs (and revenues) allocated to the Generation function are classified as either demand or energy-related.

Rate Base, Depreciation and Return

SaskPower uses the Equivalent Peaker Method, as set out in the NARUC Electric Utility Cost Allocation Manual, to classify plant in-service, accumulated depreciation, depreciation expenses and return associated with SaskPower's generation as between demand and energy. The approach uses the ratio of the unit cost of a new peaking plant (i.e., a single cycle natural gas fired unit) to the new cost of capacity for other types of generation to determine the "demand portion" for each type of generation SaskPower has in-service[28]. The only exception is wind generation where all the costs are classified to energy since SaskPower's planning studies do not ascribe any capacity value to wind generation at this time[29].

Generation OM&A expenses are classified using an analysis of fixed (demand-related) and variable (energy-related) OM&A by type of generating plant.

Fuel expenses for SaskPower's generation are classified as 100% energy-related. The classification of purchased power and import expenses is based on the capacity and energy payments to suppliers. A similar approach is used to classify the rate base and expenses associated with SaskPower International's Cory Cogeneration station.

[28] SaskPower Responses, ERCO #2.4
[29] SaskPower 2006 COSS, page 18

Export and Net Trading Revenues are classified as 100% energy-related as are SaskPower's coal reserves and the OM&A and Other Revenue associated with NorthPoint.

Shand Greenhouse assets, OM&A and depreciation expenses are classified based on the overall classification of all SaskPower generation.

The costs in the various Ancillary Service sub-functions are all classified as 100% demand-related.

Finally, the Grants in Lieu of Taxes sub-function is classified as 100% energy-related.

4.1.2 Foster's Comments and Recommendations

The Foster Report does not recommend any changes in SaskPower's Generation classification practices at this time. However, it does recommend[30] that if marginal costs are expected to remain stable or the generation function is expected to become competitive, then the Peaker Pricing Rule (utilizing system marginal energy costs) should be adopted in preference to the current NARUC approach.

4.1.3 ECS Comments

Background and General Principles

Utilities typically have a number of generation options to choose from and the choice (say between hydraulic versus fossil or natural gas versus coal or single cycle versus combined cycle generation) takes into account both the energy and the capacity requirements of a utility's customers. If generating plant is expected to operate for a significant number of hours in a year, then significant fixed costs

[30] Foster Report, page 62

(in the form of depreciation and financing expense) are frequently incurred in order to reduce energy costs over the long run or increase overall energy production[31]. Thus, apart from fuel costs, which can readily be classified as energy-related, the other costs associated with the Generation function (e.g., rate base, depreciation, and return) are typically associated with the provision of both demand and energy.

However, there is no standard/common accepted approach for classifying this portion of generation costs. Rather, there are a number of different approaches that could be and, indeed, are used by utilities. This was evident in a recent NERA report (Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies) prepared for Manitoba Hydro and filed[32] as part of the Manitoba Public Utilities Board's recent review of Manitoba Hydro's Cost of Service methodology. Similarly, the benchmarking work undertaken by Foster identifies a wide range of classification results across the utilities surveyed, particularly for hydraulic and baseload steam generation[33].

This is because one can not accurately determine the portion of costs that were incurred to support energy versus capacity requirements without a full understanding and analysis of the rationale underlying all of the investment decisions made by the utility in the past. Furthermore, the factors affecting such trade-offs change over time[34]. As result, methods such as the Peaker Pricing Rule approach preferred by Foster and the Equivalent Peaker Method presented in the NARUC Manual have been developed to provide an approximation of the excess investment in generation plant that an electric utility has made in the interests of reducing energy production costs.

[31] For example, utilities will invest in hydraulic plants where the capital cost per kW is higher than for gas-fired generation, if the plant is expected to operate for a significant portion of the year such that the lower fuelling/operating costs will offset the higher initial capital cost over the long run.
[32] Appendix 11.2 of the Main Application
[33] Foster Report, pages 12-16.
[34] As an example of these points, see the discussion regarding the Brandon GS in Section 5.3.2

In its Final Report, Foster appears to suggest[35] that the use of such methods will enhance the efficiency objective with respect to rate making but their fairness is subject to argument[36]. ECS disagrees with this premise. If additional investment costs have been incurred by a utility in the interests of securing lower energy production costs, as opposed to meeting customers' peak demands, then fairness (as based on the principle of cost causation) requires that these costs be assigned to customer classes on the basis of their energy usage.

The Foster Report notes[37] both methods will yield accurate (and equal) results if the generation mix is optimal and static. However, this is rarely the case and, as result, the two approaches can lead to different amounts of generation investment being classified as energy-related. In its discussion regarding the advantages and disadvantages of the two approaches[38], Foster prefers the Peaker Pricing Rule approach on the basis that energy-related costs will always equal marginal costs. In contrast, Foster claims that the NARUC methodology has the potential for total energy costs (i.e., energy-related generation investment cost plus average energy costs) to exceed the level of marginal energy costs.

Foster claims[39] that one of the reasons for this is that the NARUC approach treats all cost over runs and design differences as an energy-related cost. However, this is not the case with the ratio approach used by SaskPower which compares the estimated cost of a peaking plant with that of other types of generation. If there was a cost over run on one of SaskPower's single cycle gas/diesel stations then the costs would all be deemed demand-related. In contrast, if there had been a cost over run on a non-peaking plant the application of the ratio would result in a portion of the over run cost being classified as energy-related and portion being classified as demand-related.

---

[35] Pages 49-50
[36] Foster Report, pages 49-50
[37] Foster Final Report Presentation, Slide #10 and Foster Report, pages 33 and 35-36
[38] Foster Report, pages 33-36
[39] Foster Report, page 35

The one telling issue when choosing between the two methods is the fact that while natural gas generation is on the "margin" most of time and therefore natural gas prices tend to set SaskPower's marginal costs; natural gas makes up only 6% of SaskPower's generation mix[40]. This means that significant variations in natural gas prices will have a similar effect on SaskPower's marginal production costs but they will not have the same material effect on SaskPower's average cost of production. The result is that, under the Peaker Pricing Rule advocated by Foster, year to year fluctuations in natural gas prices would produce more significant variations in the overall generation cost classified to demand versus energy than the NARUC approach.

Indeed, based on SaskPower's current marginal cost of production of $60-$70/MWh[41], Foster's approach would yield a value for energy-related generation costs that exceeds the total revenue requirement functionalized as Generation[42]. In ECS's view, the NARUC Approach is to be preferred under current circumstances and careful consideration would have to be given before adopting the Peaker Pricing Rule approach.

<u>Application of the NARUC Approach</u>

As indicated earlier, SaskPower uses[43] the ratio of the unit cost of new peaking capacity to the new cost of baseload capacity for different types of generation to classify rate base (and related costs) for the generation facilities it owns. SaskPower further notes that the cost estimates were provided by its Supply Development department[44]. ECS notes that for generation such as single cycle gas, conventional coal and combined cycle it is practical to develop generic cost

[40] Foster Responses, SRRP #7
[41] Foster Responses, SaskPower #10
[42] Total energy (including losses) is 19,299 GWh (per SaskPower Response to CAPP #1.3). Using the Peaker Pricing Rule approach and a marginal cost of $65/MWh this would yield total energy-related generation costs of more than $1.2 B - a value which exceeds the total portion of SaskPower's revenue requirement that is functionalized as Generation ($933.2 M – per SaskPower 2006 COSS, page 27)
[43] SaskPower 2006 COSS, page 18
[44] SaskPower Responses, CAPP #3.7

estimates, although the estimates ($/kW) will vary depending upon underlying assumptions such as unit size. To demonstrate the reasonableness of its estimates, it would be useful if SaskPower benchmarked its cost estimates against those prepared/published by other sources.

The development of benchmark costs for hydro generation is more difficult, because the costs are likely to be very site specific. No information is provided to explain the basis for SaskPower's $2,847/kW cost for hydro generation. As the purpose of the exercise is to classify SaskPower's existing generation, the value should ideally represent the current day cost of constructing SaskPower's existing hydro-electric facilities (as opposed to the current day cost of developing a new hydro site in Saskatchewan).

These issues should be addressed in conjunction with SaskPower's next Rate Application.

Other Issues

ECS has identified issues regarding SaskPower's classification of some of the other cost items assigned to the Generation function:

- No rationale is provided for classifying all Export Revenues as energy-related. In ECS's view this approach is acceptable as long as the sales do not represent long-term commitments and are made on a short-term or interruptible basis.
- There is no explanation why Grants in Lieu of Taxes are classified as 100% energy-related. As discussed earlier, Grants in Lieu of Taxes are better considered as an overall cost of doing business in the relevant municipalities. This would suggest a more general classification is appropriate.

- The classification of Net Electricity Trading Revenues as energy-related is questionable. According to SaskPower's 2007 Rate Application[45], Net Trading Revenues arise as a result of buying electricity in external markets and then re-selling it in external markets. There is no obvious rationale for considering the net revenue to be energy-related.
- The classification approach used for the assets, OM&A and depreciation associated with the Shand Greenhouse is also open to question and will depend on the rationale for SaskPower's investment in the enterprise. If, as suggested earlier, the rationale is to provide a GHG offsets, then the costs would be more appropriately classified as energy-related.

The dollars involved in these last two items are small[46] and a change in classification would not have a material impact on the results of the Cost of Service study.

4.2 Transmission

4.2.1 SaskPower's Practice

The rate base and revenue requirement expenses (and revenues) assigned to all four Transmission Sub-Functions are classified as demand-related.

4.2.2 Foster's Comments and Recommendations

Foster notes[47] that an argument can be made that utilities make investments in transmission assets (e.g. large conductors and more efficient transformers, etc.) in order to reduce energy losses. However, it also indicates that there are other reasons for making such investments. In conclusion, Foster recommends that no changes be made at this time.

---

[45] Page 12
[46] At the time of the 2007 Rate Application the expected 2006 profit from Net Trading was $5 M (page 13) and based on the values provided in the 2006 COSS the revenue requirement impact of Shand Greenhouse is in the order of $1 M.
[47] Foster Report, page 18

4.2.3 ECS Comments

ECS's experience supports the observation made by Foster[48] that the cost impact of investments to reduce energy losses would constitute a very small percentage of the total investment related to transmission assets. Also, ECS notes that, in its experience, the predominant practice by utilities is to classify transmission costs as 100% demand related. Indeed, for the two Canadian utilities who are identified by Foster as not classifying transmission as 100% demand-related, one falls into this category because it jointly classifies all generation and transmission costs on the same basis[49]. In the other case[50], it is ECS's understanding that the Distribution utility does classify its transmission costs as 100% demand-related.

As a result, it is ECS's view that SaskPower's classification of transmission costs as 100% demand-related is appropriate.

4.3 Distribution

4.3.1 SaskPower's Practice

The following table summarizes SaskPower's current practice with respect to the classification of the various Distribution sub-functions.

Sub-Function	Classification
Sub-Stations	100% Demand
Three-Phase Primary Mains	100% Demand
Urban Single-Phase Primary Laterals	65% Demand/35% Customer
Rural Single-Phase Primary Laterals	65% Demand/35 % Customer

[48] Foster Report, page 18
[49] Nova Scotia
[50] New Brunswick

Line Transformers	70% Demand/30% Customer
Services	100% Customer
Meters	100% Customer
CIA&R	100% Customer (directly assigned)
Streetlighting	100% Customer (directly assigned)

4.3.2 Foster's Comments and Recommendations

Foster concludes[51] that SaskPower's classification approach to Distribution falls within benchmark practices and no changes are recommended at this time[52]. However, Foster notes that the split between demand/customer for primary laterals and transformers is based on data from other utilities and recommends a review should be initiated if data can be obtained to update the splits using the zero-intercept method.

4.3.3 ECS Comments

Distribution costs are typically classified as: a) 100% demand related; b) a combination of demand and customer-related or c) 100% customer-related. There is no hard and fast rules for classifying specific elements of a distribution system, particularly since the configuration and voltages used will vary from one utility to the next depending upon the transmission service voltage and the geographic positioning of customers/load across the service area. However, in general, the principle for determining whether a sub-function's costs have a customer component is to consider whether the simple existence of customers on the system (with zero or minimal load) gives rise to costs for the utility.

Following this rationale, facilities such as sub-stations (which exist because the transmission system carries large volumes of power at high voltages and are

[51] Foster Report, page 49
[52] Foster Report, page 62

unaffected by the strict distribution system customer count) are generally classified 100% demand-related. In contrast, facilities such as meters and service drops are generally classified as 100% customer related. The results of Foster's benchmarking exercise[53] indicate that this is the common practice amongst the utilities surveyed.

However, for the remaining distribution assets such as primary and secondary lines[54] and line transformers the question of demand versus customer split is not as clear cut. Some utilities take what is commonly referred to as a "basic customer" approach and use demand to allocate all costs that are not strictly customer-related[55]. Other utilities attempt to split the costs between demand and customer using either the zero-intercept or minimum system methods discussed by Foster[56] and documented in NARUC's Electric Utility Cost Allocation Manual[57]. It should also be noted that given the data requirements of these two methods utilities tend to do the analyses very infrequently or "borrow" the results generated by other utilities that are considered to be comparable.

In ECS's view it is appropriate to classify a portion of distribution plant upstream of the customer connection facilities as customer-related. ECS agrees with SaskPower's practice not to classify a portion of its distribution sub-stations as customer related. However, ECS believes that SaskPower's classification of primary mains as 100% demand-related warrants re-assessment. According to the results of Foster's benchmarking, virtually all of the Canadian electric utilities surveyed classify a portion of primary line costs as customer-related. Furthermore, ECS notes that the practice in both Ontario and Quebec, the two jurisdictions not surveyed by Foster, is to classify a portion of primary lines as customer-related.

[53] Foster Report, pages 21-25
[54] Secondary lines are those that run from the line transformers to the service drop. Note, in many utilities (including SaskPower) the accounting records do not separately record secondary lines and service drops.
[55] Examples of this are Florida and Texas as described in Foster Report, Appendix B
[56] Foster Report, pages 20-21
[57] Pages 90-95

The Foster Report expresses a preference for the zero-intercept method (versus the minimum system method) for identifying customer-related distribution facility costs. One of the reasons appears to be a concern (expressed in the NARUC Manual) that the minimum system method may result in a portion of demand being included in the customer component[58]. In ECS's view the choice between the two methods is not obvious.

First, a review of the examples cited by Foster in Appendix B of its Report shows a more frequent acceptance of the minimum system (than the zero intercept) method[59]. This result is consistent with ECS's understanding of the frequency of use of the two methods. Secondly, with respect to the concern that the minimum system results in double counting demand, the allocation of demand costs can be adjusted to account for this. Indeed, such adjustments have been implemented in Ontario and Quebec – where both jurisdictions use the minimum system method[60].

In ECS's view the update recommended by Foster should be expanded to include:

- Consideration of which methodology (minimum system or zero-intercept) is appropriate in SaskPower's circumstances,
- An assessment of whether three-phase primary main lines should be classified as both demand and customer-related and,
- An assessment of whether the Services sub-function contains a material amount of secondary conductor length that is not associated with service drops to customers and, if so, whether a portion should be classified as demand-related[61].

[58] Foster Report, page 21 and page 62
[59] Foster Report, pages 25-26
[60] For example, see OEB, EB-2005-0317, Cost Allocation Review, page 53. Found at http://www.oeb.gov.on.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf
[61] Secondary lines are those that run from the line transformers to the service drop. Note, in many utilities (including SaskPower) the accounting records do not separately record secondary lines and service drops.

4.4 Customer Service

4.4.1 SaskPower's Practice

All costs assigned to the Customer Service function are classified 100% customer-related.

4.4.2 Foster's Comments and Recommendations

Foster's notes that SaskPower's approach parallels benchmark practices and does not recommend any changes at this time[62]. It also notes that any differences between the services provided to different customer classes are captured through the allocation factors applied to the different sub-functions.

4.4.3 ECS Comments

ECS also agrees that SaskPower's practice of classifying the Customer Service sub-functions as 100% customer-related is appropriate.

5 Cost of Service Study - Allocation

5.1 Generation Costs

5.1.1 SaskPower's Practice

Energy-Related Costs

Energy-related rate base and expenses are allocated to customer classes based on the energy consumed by each customer class (as measured at the customers' meters) plus an adjustment for losses.

[62] Foster Report, pages 49 and 62

Demand-Related Costs

Demand-related rate base and expenses are allocated to customer classes using the single coincident peak (1CP) method. Under this method each customer class' contribution (including losses) to the system peak (including losses) is determined and used as the allocator.

This approach is used for both the Load and Loss sub-functions as well as the Ancillary Service sub-functions.

Interruptible Adjustment

The interruptible credit represents the credit provided to certain customers who agree to interrupt their service (i.e., reduce their demand) under certain system operating conditions. This credit is not reported as a "cost" in SaskPower's overall revenue requirement. However, offering such credits means reduced revenues from certain customers which must be recovered if SaskPower is to be "held whole" overall. In 2006, the interruptible credit was approximately $780,000[63].

The Interruptible adjustment consists of crediting (i.e., reducing the costs) for those customer classes where the interruptible customers reside and then allocating the "cost" to all SaskPower customers (except those who provide the interruptible load) using the 1CP allocator[64].

[63] SaskPower Responses, CAPP #3.20
[64] SaskPower Responses, ERCO #2.13

5.1.2 Foster's Comments and Recommendations

Foster notes that the sizing of the system (generation and transmission) is based on planning on a 1CP basis and thus 1CP reflects cost behaviour[65]. However, in its benchmarking discussion[66], Foster notes that the allocation of these costs is also done using the coincident peak for more months than just the one with the system peak and that the use of 2CP, 3CP, 4CP or (even) 12CP depends on the level of system peaks in each month.
With respect to the allocation of energy costs, Foster notes that time of use distinctions would be more reflective of costs[67].

Foster concurs with SaskPower's approach with respect to Ancillary Services and with the continued use of the current approach regarding Grants in Lieu of Taxes[68]. With respect to the interruptible credit, Foster notes that SaskPower is looking to expand its interruptible program and that there is a need to ensure consistency between the rationale for the credit, the manner in which the value of the credit was calculated and the manner in which the "cost" of the credit is allocated to customer classes[69].

5.1.3 ECS Comments

Generation Costs

Generation planning is generally not based on 1CP but rather on a more complex assessment of the probability of the loss of load/energy due to generation shortfall. However, such probabilities are heavily influenced by the highest loads in the year which results in cost of service studies using 1CP method, particularly

[65] Foster Report, page 62
[66] Foster Report, page 36
[67] Foster Report, pages 62-63
[68] Foster Report, pages 63-64
[69] Foster Report, pages 37-38 and 63-63

in instances where there is distinctive and unique system peak[70]. In the interest of stability, generation allocators are sometimes based on customers' contribution to more than just the single highest load hour of the year[71].

In its response to questions from the Panel[72], Foster notes that summer loads have been growing faster than winter loads which may impact on the allocation factors for transmission and distribution. This phenomenon could also impact on the allocation factor for generation demand costs. In ECS's view, the review Foster has recommended[73] regarding the appropriate CP factor to use for Transmission and Distribution should be expanded to include Generation[74].

ECS agrees that the introduction of time of use considerations into the allocation of energy-related costs would improve the Cost of Service Study. From SaskPower's responses to questions it appears that it plans on introducing time of use rates[75]. However, it is not clear whether or not SaskPower also plans on incorporating time of use into its Cost of Service study. In ECS view, SaskPower's plan to move towards time of use rates increases the need to incorporate time of use considerations into its Cost of Service study.

Ancillary Services

There is no discussion in either the SaskPower or Foster materials regarding the use of 1CP to allocate Ancillary Services. Indeed the use of 1CP appears to be a carry over from Generation (just as the costs of Ancillary Services are developed from Generation). In the interest of transparency there should be a separate

[70] This point is acknowledged in the Foster Report, page 36
[71] For example, in using the 2CP method, Manitoba Hydro allocates costs based on each class' average demand in the highest 50 winter and highest 50 summer coincident hours.
[72] Foster Responses, SRRP #9 a) & b)
[73] Foster Report, page 64
[74] Such a review would include an assessment of whether the peak demand consistently occurred in the same month each year and whether, in a given year, there were other months where the peak demand was close to the overall system peak.
[75] SaskPower Responses, ERCO #2.11 and CAPP #3.12

discussion on Ancillary Services (for both classification and allocation) reflecting the cost drivers that determine the level of these services required by the SaskPower system.

Interruptible Adjustment

ECS agrees with Foster's observations regarding the need for consistency in the treatment of the interruptible credit.

Grants in Lieu of Taxes

As discussed above, consideration should be given to a more generic classification/allocation such as pro-rating to all customer classes based on their overall assessed cost of service.

5.2 Transmission Costs

5.2.1 SaskPower's Practice

All of the Transmission sub-functions are classified as 100% demand-related and the costs are allocated to customer classes using the 1CP method[76]. For each of the sub-functions, the 1CP allocator reflects the contribution of each customer class to the output from the relevant assets. This results in different allocation factors for Main Grid versus 138 kV Lines versus 138/72 kV Substations and 72 kV Lines[77]. The reason is that, with the exception of the Main Grid, not all customers on the system use all of these assets.

[76] SaskPower 2006 COSS, page 21
[77] Foster 2006 COSS, pages 63& 66

5.2.2 Foster's Comments and Recommendations

The Foster Report concludes that there should be no change in the choice of allocation factors for Transmission at this time[78]. However, Foster also recommends that, once the load research program is completed[79], an assessment should be made as to the appropriateness of using summer versus winter CP allocation factors.

5.2.3 ECS Comments

ECS agrees that SaskPower's use of coincident peak to allocate the costs of all its Transmission sub-functions is reasonable at this time and that there is need to review system data to determine if the allocation factor should be expanded beyond the system peak (i.e., beyond 1CP).

ECS notes that there may be difference in the cost drivers underlying the Main Grid versus the other sub-functions. Investment requirements for the Main Grid are typically driven by overall system need and therefore consideration of system peak values is clearly relevant. However, this may not be the case when it comes to the other sub-functions (i.e., the 138/72 kV Substations as well as the 138 kV and 72 kV Radial Lines). It may be the case where, even at this point, geographical and customer base differences mean that the loads driving costs for these components of the SaskPower System are not coincident with the system peak. In ECS's view, it would be useful if the proposed review also looked at the usage of these three asset groups and whether it is appropriate to use the same demand allocator[80] as applied to the Main Grid costs.

---

[78] Foster Report, page 64

[79] It is ECS's understanding that SaskPower does not currently have data that would allow it to establish coincident peak allocation factors for other than the one-hour winter system peak. (Foster Responses, SRRP # 9 a))

[80] Alternatives could include the use of a CP factor that considers more months of year or even an NCP factor depending upon the results of the analysis.

5.3 Distribution Costs

5.3.1 SaskPower's Practice

The following table summarizes SaskPower's current practice with respect to the allocation of the various Distribution sub-functions.

Sub-Function	**Allocation**[81]	
	Demand	**Customer**
Sub-Stations	1CP	N/A
Three-Phase Primary Mains	1CP	N/A
Urban Single-Phase Primary Laterals	1CP	# of Urban Customers
Rural Single-Phase Primary Laterals	1CP	# of Rural Customers
Line Transformers	1NCP	# of Customers with Transformer
Services	N/A	# of Customers Weighted by Cost of Connection / Class
Meters	N/A	# of Customers Weighted by Meter Cost / Class
CIA&R	N/A	Direct Allocation
Streetlighting	N/A	Direct Allocation

In terms of the demand allocation factors, 1NCP factors are calculated by looking at the maximum demand for each customer class regardless of when that maximum occurs.

[81] Foster 2006 COSS, page 67

In terms of the customer allocation factors, Meter costs are allocated by weighting the number of customers in each class by the installed cost of the type of meter used for each respective class. Similarly, for Services, the number of customers is weighted by the typical cost of a service connection for each class.

5.3.2 Foster's Comments and Recommendations

Foster states that use of the 1CP allocator for substations and primary lines is reasonable. However, they also state that the current or an expanded load research program would enable SaskPower to estimate class contribution to each substation and possibly each feeder[82]. With respect to Line Transformers, Foster states that continued use of the NCP method seems appropriate in order to avoid a load analysis for each transformer.

Consistent with its views on Transmission, Foster also recommends that SaskPower revisit the appropriateness of using a winter, summer or some combination of the two CP allocation factors for allocating distribution costs[83].

5.3.3 ECS Comments

Demand Allocators

Foster's benchmarking work indicates that an NCP allocation factor is the most common approach used by the utilities surveyed for all distribution assets[84]. This finding is consistent with the NARUC Manual which states that "customer-class non-coincident demands (NCPs) and individual customer demands are the load

[82] Foster Report, pages 53-54
[83] Foster Report, page 54
[84] Foster Report, page 39

characteristics that are normally used to allocate the demand component of distribution facilities”[85].

ECS does not agree with Foster’s conclusion[86] that SaskPower’s current allocation approach to distribution closely aligns with benchmark practices.

In the case of distribution substations there is a boundary issue where some utilities may consider such stations to be part of their Transmission function. As result, ECS accepts that the continued use of the 1CP factor is reasonable at this time provided the load research recommended by Foster is undertaken and expanded to consider whether the peak demand recorded on SaskPower’s various distribution substations is coincident with its monthly system peaks. If there is substantial divergence, an NCP allocation factor may be appropriate.

At one point in its Report Foster observes[87] that:

> “Distribution substations and primary lines serve multiple rate classes and the sizing of these facilities is based upon the peak demand supplied by the facility which is more closely related to the coincident peak of the rate classes than it is to the sum of their individual rate class peak demands”.

However, elsewhere Foster states[88] that:

> The cost driver for distribution substations is the contribution each class to the peak on the substation. The same is true for each individual feeder form each substation. The current or possible an expand load research program would enable SaskPower to estimate class contribution to each substations and possibly each feeder.

While the first quote would support the use of 1CP, the second quote suggests that an NCP type approach may be more appropriate until a more detailed analysis of each station and feeder is undertaken.

[85] Page 97
[86] Foster Report, page 54
[87] Page 53
[88] Page 54

As discussed above, with respect to primary lines, there is compelling evidence that NCP is the standard approach. In ECS view, a more reasonable approach would be to adopt the use of an NCP allocator for primary lines (both mains and laterals), until more research is completed.

Customer Allocators

With the exception of the allocation approach used for CIA&R (which has been discussed earlier), ECS agrees with the customer-based allocators used by SaskPower for its various Distribution sub-functions. SaskPower's practices conform to ECS experience with other utilities and with the approach set out in the NARUC Manual[89].

5.4 Customer Service

5.4.1 SaskPower's Practice

Each Customer Service sub-function represents a different activity area/department within SaskPower. In each case, the costs are allocated to customer classes based on the weighted number of customers in the class – where the weightings reflect how much time the Customer Service departments spend with each customer class[90].

[89] Page 98
[90] SaskPower 2006 COSS, page 21

5.4.2 Foster's Comments and Recommendations

Foster notes[91] that the allocation of customer service parallels benchmark practices but does not present any conclusions or recommendations in this area.

5.4.3 ECS Comments

The approach used by SaskPower is reasonable and consistent with standard practice.

6 Summary

6.1 Functionalization

Functions Used

- The functions and sub-functions employed by SaskPower are generally reasonable.
- It is not clear if SaskPower needs to maintain separate sub-functions for Load and Losses. If it does, a clear explanation how costs are assigned to the two sub-functions should be provided.
- SaskPower should reconsider its direct assignment to customer classes of the Contributions in Aid and Reconstruction associated with customer class services and streetlights.

Cost Functionalization

- There are a number of specific instances where the rationale and/or methodology for SaskPower's assignment of costs to function and sub-functions are not apparent. These include:
    - The reassignment of a portion of Transmission rate base and OM&A to Generation.

[91] Foster Report, page 54

  - o The functionalization (and subsequent classification) of Grants in Lieu of Taxes and the Shand Greenhouse.
  - o The treatment of DSM-related expenditures.
- These issues should be addressed in SaskPower's next Rate Application.

6.2 Classification

Generation

- Generation plant costs should continue to be classified using the NARUC approach. At the time of its next Rate Application, SaskPower should benchmark the capital costs per kW used in the calculation against those published by third parties and provide an explanation as to the derivation of the Hydro cost per kW used.
- There are a number of specific instances where the rationale for classifying a particular cost element is not obvious and an explanation should be provided by SaskPower in its next Rate Application:
  - o The classification of all Export Revenues as energy-related.
  - o The classification of Net Electricity Trading Revenue as 100% energy-related.
  - o The classification of the Shand Greenhouse costs as both demand and energy-related.

Transmission

- SaskPower's classification of Transmission costs as 100% demand-related is reasonable.

Distribution

- SaskPower's classification of Sub-Stations as 100% demand-related is reasonable.
- SaskPower's classification of Distribution Mains as 100% demand-related should be reconsidered. This reconsideration should be part of a larger

review of SaskPower's classification of Distribution Mains. Urban and Rural Laterals, Line Transformers and Services. The review should also include consideration of whether the minimum system or zero intercept methodology is the more appropriate approach for SaskPower's system.

- SaskPower's classification of service drops and meters as customer-related is reasonable.

Customer Service

- SaskPower's classification of Customer Service costs as 100% customer-related is reasonable – provided that appropriate weightings are applied in the allocation phase.

6.3 Allocation

Generation

- There is a need to review SaskPower's overall system load characteristics to determine if 1CP continues to be the appropriate allocator for demand-related generation costs.
- Time-differentiation of SaskPower's energy production costs would improve its Cost of Service study and support the introduction of time of use rates.
- Consideration should be given to a more generic allocation for Grants in Lieu of Taxes.
- In the interest of transparency, an explanation should be provided regarding the allocators used for Ancillary Services.

Transmission

- As noted by Foster, there is a need to reconsider whether the 1CP method continues to be the appropriate allocator for Transmission costs.
- As part of this review, SaskPower should also assess whether the same allocator is appropriate for all Transmission sub-functions.

Distribution

- SaskPower's use of 1CP to allocate demand-related costs for Mains and Laterals is questionable and needs to be reassessed. In the interim, use of a 1NCP allocator would conform more closely with standard industry practice.
- The make-up of the Services sub-function needs to be reviewed to determine if a material portion of the costs are associated with facilities other than actual service connections.
- As noted earlier, the direct assignment of CIA&R needs to be reconsidered. Otherwise, SaskPower's allocation of customer-related costs is reasonable.

Customer Service

- SaskPower's allocation of the costs in the various Customer Service sub-functions is reasonable and consistent with standard industry practice.

ECONALYSIS CONSULTING SERVICES

William O. Harper

Mr. Harper has over 25 years experience in the design of rates and the regulation of electricity utilities. While employed by Ontario Hydro, he has testified as an expert witness on rates before the Ontario Energy Board from 1988 to 1995, and before the Ontario Environmental Assessment Board. He was responsible for the regulatory policy framework for Ontario municipal electric utilities and for the regulatory review of utility submissions from1989 to 1995. Mr. Harper also coordinated the participation of Ontario Hydro (and its successor company Ontario Hydro Services Company) in major public reviews involving Committees of the Ontario Legislature, the Ontario Energy Board and the Macdonald Committee. He has served as a speaker on rate and regulatory issues for seminars sponsored by the APPA, MEA, EPRI, CEA, AMPCO and the Society of Management Accountants of Ontario. Since joining ECS, Mr. Harper has provided consulting support for client interventions on energy and telecommunications issues before the Ontario Energy Board, Manitoba Public Utilities Board, Québec's Régie de l'énergie, British Columbia Utilities Commission, and CRTC. He has also appeared before the Manitoba's Public Utilities Board, the Manitoba Clean Environment Commission, the Ontario Energy Board and Quebec's Régie de l'énergie. Bill is currently a member of the Ontario Independent Electricity System Operator's Technical Panel.

EXPERIENCE

Econalysis Consulting Services- Senior Consultant
2000 to present

- Responsible for supporting client interventions in regulatory proceedings, including issues analyses & strategic direction, preparation of interrogatories, participation in settlement conferences, preparation of evidence and appearance as expert witness (where indicated by an asterix). Some of the more significant proceedings included:

- <u>Electricity (Ontario)</u>
  - IMO 2000 Fees (OEB)
  - Hydro One Remote Communities Rate Application 2002-2004
  - OEB - Transmission System Code Review (2003)
  - OEB - Distribution Service Area Amendments (2003)
  - OEB - Regulated Asset Recovery (2004)
  - OEB - 2006 Electricity Rate Handbook Proceeding*
  - OEB - 2006 Rate Applications by Various Electricity Distributors
  - OEB - 2006 Guidelines for Regulation of Prescribed Generation Assets
  - OEB – 2006 Cost Allocation Review
  - OEB - 2007 Rate Applications by Various Electricity Distributors

- OEB - 2007 Cost of Capital and 2nd Generation Incentive Regulation Proceeding
- OEB - Hydro One Networks 2007/2008 Transmission Rate Application
- OEB - 2008 Rate Applications by Various Electricity Distributors

- Electricity (British Columbia)
  - BC Hydro IPP By-Pass Rates
  - BC Hydro Heritage Contract Proposals
  - BC Hydro's 2004/05 and 2005/06 Revenue Requirement Application
  - BC Hydro's CFT for Vancouver Island Generation – 2004
  - BC Hydro's 2005 Resource Expenditure and Acquisition Plan
  - BC Hydro's 2006 Residential Time of Use Rate Experiment Application
  - BC Hydro's 2006 Integrated Electricity Plan
  - BC Hydo's 2006/07 and 2007/08 Revenue Requirement Application
  - BC Hydro's 2007 Rate Design Application
  - BC Hydro's 2008 Residential Inclining Block Rate Application
  - BC Transmission Corporation – Open Access Transmission Tariff Application - 2004
  - BCTC's 2005/06 Revenue Requirement Application
  - BCTC's – 2005 Vancouver Island Transmission Reinforcement Project
  - BCTC's 2006/07 Revenue Requirement Application
  - BCTC' 3007/2008 Revenue Requirement Application
  - WKP Generation Asset Sale
  - Fortis BC's 2005 Revenue Requirement and System Development Application
  - Fortis BC's 2006 Revenue Requirement Application
  - Fortis BC's 2007/08 Capital Plan and System Development Plan
  - Fortis BC's 2007 Revenue Requirement Application
  - FortisBC's 2007 Rate Design Application
  - FortisBC's 2008 Revenue Requirement Application

- Electricity (Quebec)
  - Hydro Québec-Distribution's 2002-2011 Supply Plan*
  - Hydro Quebec-Distribution's 2002-2003 Cost of Service and Cost Allocation Methodology*
  - Hydro Québec - Distribution's 2004-2005 Tariffs*
  - Hydro Québec - Distribution's 2005/2006 Tariff Application*
  - Hydro Québec - Distribution's 2005-2014 Supply Plan*
  - Hydro Québec - Distribution's 2006/2007 Tariff Application*
  - Hydro Québec - Transmission's 2005 Tariff Application*
  - Hydro Québec - Distribution's 2006 Interruptible Tariff Application
  - Hydro Québec - Distribution's 2006 Cost Allocation Work Group
  - Hydro-Québec - Transmission's 2007 Tariff Application
  - Hydro-Québec - Distribution's 2007/08 Tariff Application*
  - Hydro-Québec - Distribution's 2008/09 Tariff Application*
  - Hydro-Québec – Transmission's 2008/09 Tariff Application

- <u>Electricity (Manitoba)</u>
  - Manitoba Hydro's Status Update Re: Acquisition of Centra Gas Manitoba Inc.*
  - Manitoba Hydro's Diesel 2003/04 Rate Application
  - Manitoba Hydro's 2004/05 and 2005/06 Rate Application*
  - Manitoba Hydro/NCN NFAAT Submission re: Wuskwatim*
  - Manitoba Hydro's 2005 Cost of Service Methodology Submission*
  - Manitoba Hydro's 2007 Rate Adjustment Application
  - Manitoba Hydro's 2008/09 Rate Application

- <u>Natural Gas Distribution</u>
  - Enbridge Consumers Gas 2001 Rates
  - BC Centra Gas Rate Design and Proposed 2003-2005 Revenue Requirement
  - Rate of Return on Common Equity (BCUC)
  - Terasen Gas (Vancouver Island) LNG Storage Project (2004)

- <u>Telecommunications Sector</u>
  - Access to In-Building Wire (CRTC)
  - Extended Area Service (CRTC)
  - Regulatory Framework for Small Telecos (CRTC)

- <u>Other</u>
  - Acted as Case Manager in the preparation of Hydro One Networks' 2001-2003 Distribution Rate Applications
  - Supported the implementation of OPG's Transition Rate Option program prior to Open Access in Ontario
  - Prepared Client Studies on various issues including:
    - The implications of the 2000/2001 natural gas price changes on natural gas use forecasting methodologies.
    - The separation of electricity transmission and distribution businesses in Ontario.
    - The business requirements for Ontario transmission owners/operators.
    - Various issues associated with electricity supply/distribution in remote communities
  - Member of the OEB's 2004 Regulated Price Plan Working Group
  - Member of the OEB's 2005/06 Cost Allocation Technical Advisory Team
  - Member of the IESO Technical Panel (April 2004 to Present)

Hydro One Networks
Manager - Regulatory Integration, Regulatory and Stakeholder Affairs
(April 1999 to June 2000)

- Supervised professional and administrative staff with responsibility for:
  - providing regulatory research and advice in support of regulatory applications and business initiatives;
  - monitoring and intervening in other regulatory proceedings;
  - ensuring regulatory requirements and strategies are integrated into business planning and other Corporate processes;

  - providing case management services in support of specific regulatory applications.
- Acting Manager, Distribution Regulation since September 1999 with responsibility for:
  - coordinating the preparation of applications for OEB approval of changes to existing rate orders; sales of assets and the acquisition of other distribution utilities;
  - providing input to the Ontario Energy Board's emerging proposals with respect to the licences, codes and rate setting practices setting the regulatory framework for Ontario's electricity distribution utilities;
  - acting as liaison with Board staff on regulatory issues and provide regulatory input on business decisions affecting Hydro One Networks' distribution business.
- Supported the preparation and review before the OEB of Hydro One Networks' Application for 1999-2000 transmission and distribution rates.

Ontario Hydro
Team Leader, Public Hearings, Executive Services (Apr. 1995 to Apr. 1999)

- Supervised professional and admin staff responsible for managing Ontario Hydro's participation in specific public hearings and review processes.
- Directly involved in the coordination of Ontario Hydro's rate submissions to the Ontario Energy Board in 1995 and 1996, as well as Ontario Hydro's input to the Macdonald Committee on Electric Industry Restructuring and the Corporation's appearance before Committees of the Ontario Legislature dealing with Industry Restructuring and Nuclear Performance.

Manager – Rates, Energy Services and Environment (June 1993 to Apr. 95)
Manager – Rate Structures Department, Programs and Support Division (February 1989 to June 1993)

- Supervised a professional staff with responsibility for:
  - Developing Corporate rate setting policies;
  - Designing rates structures for application by retail customers of Ontario Hydro and the municipal utilities;
  - Developing rates for distributors and for the sale of power to Hydro's direct industrial customers and supporting their review before the Ontario Energy Board;
  - Maintaining a policy framework for the execution of Hydro's regulation of municipal electric utilities;
  - Reviewing and recommending for approval, as appropriate, municipal electric utility submissions regarding rates and other financial matters;
  - Collecting and reporting on the annual financial and operating results of municipal electric utilities.
- Responsible for the development and implementation of Surplus Power, Real Time Pricing, and Back Up Power pricing options for large industrial customers.
- Appeared as an expert witness on rates before the Ontario Energy Board and other regulatory tribunals.

- Participated in a tariff study for the Ghana Power Sector, which involved the development of long run marginal cost-based tariffs, together with an implementation plan.

Section Head – Rate Structures, Rates Department
November 1987 to February 1989

- With a professional staff of eight responsibilities included:
    - Developing rate setting policies and designing rate structures for application to retail customers of municipal electric utilities and Ontario Hydro;
    - Designing rates for municipal utilities and direct industrial customers and supporting their review before the Ontario Energy Board.
- Participated in the implementation of time of use rates, including the development of retail rate setting guidelines for utilities; training sessions for Hydro staff and customers presentations.
- Testified before the OEB on rate-related matters.

Superintendent – Rate Economics, Rates and Strategic Conservation Department
February 1986 to November 1987

- Supervised a Section of professional staff with responsibility for:
    - Developing rate concepts for application to Ontario Hydro's customers, including incentive and time of use rates;
    - Maintaining the Branch's Net Revenue analysis capability then used for screening marketing initiatives;
    - Providing support and guidance in the application of Hydro's existing rate structures and supporting Hydro's annual rate hearing.

Power Costing/Senior Power Costing Analyst, Financial Policy Department
April 1980 to February 1986

- Duties included:
    - Conducting studies on various cost allocation issues and preparing recommendations on revisions to cost of power policies and procedures;
    - Providing advice and guidance to Ontario Hydro personnel and external groups on the interpretation and application of cost of power policies;
    - Preparing reports for senior management and presentation to the Ontario Energy Board.
- Participated in the development of a new costing and pricing system for Ontario Hydro. Main area of work included policies for the time differentiation of rates.

Ontario Ministry of Energy
Economist, Strategic Planning and Analysis Group
April 1975 to April 1980

- Participated in the development of energy demand forecasting models for the province of Ontario, particularly industrial energy demand and Ontario Hydro's demand for primary fuels.
- Assisted in the preparation of Ministry publications and presentations on Ontario's energy supply/demand outlook.
- Acted as an economic and financial advisor in support of Ministry programs, particularly those concerning Ontario Hydro.

EDUCATION

Master of Applied Science – Management Science

- University of Waterloo, 1975
- Major in Applied Economics with a minor in Operations Research
- Ontario Graduate Scholarship, 1974

Honours Bachelor of Science

- University of Toronto, 1973
- Major in Mathematics and Economics
- Alumni Scholarship in Economics, 1972