2 Toronto Street, Suite 222
Toronto, Ontario, M5C 2B5
elenchus.ca

Review of SaskPower Cost Allocation and Rate Design Methodologies

Report prepared by
Elenchus Research Associates Inc.

DRAFT

DRAFT

9 May 2023

Page Intentionally Blank

Table of Contents

Page Intentionally Blank

1 OVERVIEW

SaskPower retained Elenchus Research Associates (Elenchus) to:

1. Review and assess SaskPower's existing cost of service methodology.
2. Review and assess common and accepted cost of service methodology in the electrical utility industry in Canada and the United States.
3. Survey the functionalization, classification and allocation methodologies currently in use by Canadian electric utilities as well as the functionalization, classification and allocation results in percentages.
4. Verify whether the current methodology is consistent with accepted electric power utility practices and is appropriate for SaskPower's system characteristics.
5. Propose, if required, the enhancement of SaskPower's cost of service methodology including the reasons for the changes.
6. Review SaskPower's rate design methodology.

This report consists of 5 additional sections.

Section 2 provides a very brief overview of the standard approach to cost allocation that is widely accepted by regulators across Canada and internationally.

Section 3 extends the discussion of the principles on which the Elenchus review is based by summarizing generally accepted rate making (Bonbright) principles, as the tailored version of those general principles that guide SaskPower approach to rate making.

Section 4 provides an overview of SaskPower's cost allocation methodology, recognizing that this methodology is fully documented in "2021 Fiscal Base Embedded Cost of Service Study", dated November 28, 2022, which has been prepared by SaskPower. Elenchus has reviewed this documentation to confirm that the SaskPower model is consistent with the documentation of the methodology.

Section 5 presents the results of Elenchus's review of the cost allocation methodologies currently used by selected (major) Canadian and U.S. electric utilities.

Section 6 contains Elenchus comments and recommendations based on our review of the SaskPower cost allocation model and its approach to rate design in light of generally accepted regulatory principles, current standard practices across jurisdictions and the specific operational circumstances of SaskPower.

Section 7 includes the comments received from stakeholders on Elenchus' review and recommendations in this report and provides Elenchus' responses to the comments. (NTD: this section will be updated after the May 17 presentation to respond to any further questions received from stakeholders.)

Appendix A includes the documentation of SaskPower's Cost Allocation Methodology.

Appendix B provides a list of the utilities surveyed and results of the jurisdiction review.

Appendix C includes the qualifications of the Elenchus' team that conducted the study and prepared this report.

2 COST ALLOCATION

It is standard practice in Canada and in many jurisdictions internationally to rely on cost allocation studies to apportion utility assets and expenses to a utility's customer classes that are consistent with the NARUC Electric Utility Cost Allocation Manual.[1] Because most of the assets and expenses of an electrical power system are used jointly by multiple customer classes, cost allocation studies are used to apportion a utility's revenue requirement among customer classes on a fair and equitable basis as guided by the principle of cost causality.

Traditionally there are three steps that are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, each account in the utility's system of accounts is functionalized. That is, the function(s) served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as demand, energy and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers.

Allocation, which is the final step, is the process of attributing the demand, energy and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to demand, energy, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class. For example, if the necessary investment in a particular class of asset (e.g., certain transmission lines) is caused strictly by the single peak in annual demand, then the

[1] A standard reference document for cost allocation methodologies continues to be the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992. A subsequent NARUC publication, "Cost Allocation for Electric Utility Conservation and Load Management Programs" (1993) extends the application of the basic principles to conservation and demand side management (DSM) programs.

relevant costs would be allocated using the 1-coincident peak (1-CP) method. The actual application of these broad principles in the context of SaskPower is explained in section 4.

In some instances, assets and/or costs can be related directly to a particular customer class and are then directly assigned to the customer class, for example streetlight assets and expenses can be directly allocated to the streetlight customer class, by-passing the categorization step.

Cost allocation studies can be done using historical actual data or using future test year forecast data. The information needed is the utilities' financial data related to assets and expenses as well as sales data. The financial data is usually based on the accounting system used by the utility. The sales data used is by customer class and includes for example number of customers, energy (kWh) and demand (kW or kVA) consumption.

Cost allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes.

The ratio of revenue to cost illustrates the extent to which the class is paying for their share of costs imposed on the utility. While recognizing that the allocation of costs cannot be done with precision, a revenue to cost ratio of 1 or above 1 indicates that the class is paying their fair share of costs or even more than their fair share. A revenue to cost ratio below 1 indicates that the class is not paying for their fair share of costs.

The analytic results are viewed as indicators since the allocation of shared costs amongst various customer classes cannot be done in a precisely accurate way. As a result, in many jurisdictions a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of striving to achieve a revenue to cost ratio of exactly 1.00 for all customer classes. Many jurisdictions use a range of 0.95 to 1.05, or 0.90 to 1.10 as acceptable revenue to cost ratios when establishing revenue responsibilities by customer class.

3 Generally Accepted Rate Making Principles

It is generally accepted by utility regulators that any utility's cost allocation methodology and approach to rate design should be based on a set of clearly enunciated principles. These principles then guide the work that is undertaken to allocate assets and expenses to customer groups appropriately and establish rates that recover those costs from customers in a manner that is consistent with the principles.

The most commonly used reference for defining these ratemaking principles is the seminal work of James Bonbright.[2] Chapter 16 (pages 383-384) of the Second Edition sets out ten "attributes of a sound rate structure":

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.*

2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*

3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

Cost-related Attributes:

4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:*

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. *Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).*

6. *Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3)*

[2] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*
8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

Practical-related Attributes

9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*
10. *Freedom from controversies as to proper interpretation.*

It is inevitable that in applying these principles, conflicts arise in trying to apply all the principles simultaneously. For example, an allocation that is more equitable may compromise economic efficiency or simplicity. Determining the optimal trade-offs between the principles in developing rates therefore requires judgment. For this reason, cost allocation and rate design are often referred to as being as much art as science.

SaskPower's six stated key objectives[3] for its cost of service study and resulting rate design are consistent with the Bonbright principles and appear to encompass all ten of the principles set out by Bonbright in 1988. The SaskPower objectives are:

1. Meeting revenue requirement
2. Fairness and equity
3. Economic efficiency
4. Conservation of resources
5. Simplicity and administrative ease
6. Stability and gradualism

The flowing sub-sections set out our interpretation of SaskPower's objectives.

[3] 2021 Fiscal Base Embedded Cost of Service Study, November 28, 2022

3.1 Meeting Revenue Requirement

Meeting SaskPower's revenue requirement implies that customer rates should be set to yield sufficient revenues for the utility to recover its approved costs. The recoverable costs that make up the company's revenue requirement include all operating, maintenance and administration expenses, including amortization, as well as the cost of capital. The cost of capital includes both the interest on outstanding debt and a return on equity (or interest coverage) that enables the utility to be financially sound.

3.2 Fairness and Equity

Fairness and equity are understood to mean that the utility's assets and expenses have been apportioned to the customer classes in a manner that has cost causality as the main criterion. The methodologies used to apportion costs follow criteria that can be measured in a fair way and can be understood and accepted by stakeholders. Most of the utilities assets and expenses are shared by all or most of the utility's customers and cost causality parameters are developed to assign the assets and expenses to customer groups.

3.3 Economic Efficiency

Economic efficiency means that the utility's assets and expenses are being utilized effectively (operational efficiency) and, to the extent practical, the rates charged customers provide reasonable price signals that allow the utility to develop the power system in a manner that is efficient through time (dynamic efficiency).

3.4 Conservation of Resources

Conservation of resources is a further dimension of economic efficiency in that the design of rates should result in price signals that encourage consumers to use power in a manner that maintains a reasonable balance between the cost of supplying power to consumers and the value of that power to consumers.

3.5 Simplicity and Administrative Ease

Simplicity and administrative ease are criteria that address the need to use cost allocation and rate design methods that are understandable by stakeholders and customers and are implementable by the utility given its available capabilities and resources.

3.6 Stability and Gradualism

Stability and gradualism are criteria that deal with the need to use cost allocation and rate design approaches that produce stable results over time and manageable/gradual changes as a result of changing circumstances. The purpose of the criteria is to avoid, to the extent practical, approaches that produce sudden and significant changes in cost allocation and rate design as a result of changing circumstances. This is not intended as an impediment to appropriate changes, but rather a recognition that significant changes in the level of charges can be difficult for consumers to absorb in their daily lives. Hence, when circumstances justify changes that may have a significant impact on customer bills, it is desirable to phase in the changes in a manner that mitigates bill impacts without unduly compromising the other objectives of SaskPower's cost allocation and rate design.

4 SaskPower Cost Allocation Methodology

SaskPower cost allocation methodology[4] follows the standard industry approach of Functionalization, Classification and Allocation of assets and costs to customer classes.

4.1 Functionalization

The asset and expense functions utilized by SaskPower to group assets and costs of a similar nature include the following:

1. Generation:
    i. Load
    ii. Losses
    iii. Scheduling and Dispatch
    iv. Regulation and Frequency Response
    v. Spinning Reserve
    vi. Supplementary Reserve
    vii. Planning Reserve
    viii. Reactive Supply
    ix. Grants in Lieu of Taxes
2. Transmission

[4] Ibid

    i. Main Grid
    ii. 230 kV & 138 kV Lines Radials
    iii. 138/72 kV Substations
    iv. 72 kV Lines Radials

3. Distribution

    i. Area Substations
    ii. Distribution Mains
    iii. Urban Laterals
    iv. Rural Laterals
    v. Transformers
    vi. Services
    vii. Instrument Transformers
    viii. Meters
    ix. Streetlights
    x. Customer Contributions

4. Customer Service

    i. Metering Services
    ii. Meter Reading
    iii. Billing and Customer Accounts
    iv. Customer Collecting
    v. Service & Support
    vi. Customer Strategy & Planning

The functions used by SaskPower provide enough differentiation of assets and costs by grouping assets and costs of a similar nature in the cost allocation methodology to enable the classification and allocation of assets and costs to customer classes using cost causality principles. The extent of the breakdown into functions is consistent with other Canadian power utilities.

Additional details on the functionalization step followed by SaskPower in its cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to functionalization is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.2 CLASSIFICATION

SaskPower classifies assets and costs into demand related, energy related and customer related, consistent with the standard practice of other Canadian power utilities. Classifying assets and costs into these three categories allows for the subsequent proper allocation of these assets and costs to customer classes.

The methodology currently used by SaskPower to separate generation rate base and depreciation expenses into demand related and energy related is the Average & Excess Demand method. This method considers the average annual demand required to meet its energy requirements, and any demand in excess of the average is required to meet peaking requirements. This method is used to classify all generation rate base, including wind generation.

The assets and expenses associated with Purchased Power Agreements (PPA's) are classified to demand and energy using the contractual capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified as 100% energy related as is common practice in the cost allocation studies of other Canadian power utilities with rate regulated generation functions.

Transmission facilities are classified as 100% demand related. This also is the usual approach for these types of assets and costs.

Distribution substations and three phase feeders are classified 100% demand related. Urban and rural single-phase primary lines are classified 30% demand-related and 70% customer-related. Line transformers are classified 65% demand-related and 35% to customer-related based on the Minimum System Method.

All secondary lines, services, and meters are classified 100% customer related.

Customer related assets and costs are classified 100% to customer.

More details on the classification of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to classification is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.3 Allocation

The last step in SaskPower's cost allocation study allocates the demand, energy and customer related assets and costs to SaskPower's customer classes. Classifying assets and costs into demand, energy and customer related, allows for the allocation of these assets and costs using the appropriate parameters (i.e., allocators) that reflect cost causality. For example, it allows for energy consumed by customer class to be used to allocate energy related assets and costs, and for the number of customers to be used to allocate customer related assets and costs that are driven by the number of customers.

Demand related generation assets and costs and transmission assets and costs are allocated to customer classes using the two coincident peak (2-CP) method based on demand, adjusted for the estimated associated losses. Energy related generation assets and costs are allocated to customer classes based on the energy consumed by customer classes, adjusted to include estimated losses.

Distribution demand related assets and costs are allocated to customer classes based on a combination of the two-coincident peak method for most functions and the Maximum Diversified Class Demands (MDD) method for the transformers function.

Customer related assets and costs are allocated to customer classes based on a combination of methods based on the number of customers by customer class for some assets and costs and the weighted number of customers by customer class for other assets or costs (e.g., where average per customer costs differ across classes, such as meter costs).

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to allocation is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.4 Customer classes

The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expenses are allocated. Each rate class may have multiple rate codes.

- Residential
- Farms
- Commercial
- Power - Published Rates
- Power - Contract Rates
- Oilfields

- Streetlights
- Reseller

More details on the allocation of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

SaskPower also conducted studies to develop appropriate customer class load profiles based on valid sampling of customers. SaskPower also utilizes a study of losses to determine the losses incurred in providing electricity to its various customer groups.

More details on the customer load profiles and loss study conducted by SaskPower are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

5 Survey of Functionalization, Classification, and Allocation Methodologies

Elenchus conducted a jurisdiction review of ten Canadian and US utilities with respect to the cost allocation methodologies currently being used in the industry. Special emphasis was placed on obtaining information from Canadian utilities.

Functionalization of assets and expenses, classification of functionalized assets, and allocation methodologies were surveyed, and the results of the survey are included in this report and more details of the jurisdiction review are provided in Appendix B.

As a result of deregulation in the electricity sector, some generators no longer follow a cost allocation approach to determine how to allocate their assets and costs to customer classes and to develop appropriate rates. Instead, generators bid their supply to electricity system market operators or have bi-lateral agreements that have specified prices. Revenues are based on market prices for electricity.

The tables in this section reflect the results of the jurisdiction review and SaskPower's placement within each table. SaskPower's placement is denoted with an asterisk (*). For clarity, SaskPower is not included in the utility counts.

5.1 Functionalization

5.1.1 Generation Functionalization

The methodologies used to functionalize generation assets varies based on the generation assets owned and operated by each utility.

Functions are not always well-defined and are often broken out into subfunctions. The number of functions used by each utility does not necessarily reflect the degree of detail used in cost allocation since most generation functions are classified in the same way. A utility may have a single generation function for all its generation station assets, or it may list each generation station separately.

The number of generation asset and expense functions is summarized in Table 1.

Table 1: Functionalization methodology used for generation assets and expenses		
Number of Functions	Number of Utilities	Percent of Utilities
8-10	1*	10
6-7	1	10
4-5	1	10
2-3	5	50
NA	2	20
Totals	**10**	

5.1.2 Transmission Functionalization

The number of transmission asset and expense functions is summarized in Table 2.

Table 2: Functionalization methodology used for transmission assets and expenses		
Number of Functions	Number of Utilities	Percent of Utilities
6-8	2	20
3-5	1*	10
2	2	20
1	4	40
NA	1	10
Totals	**10**	

5.1.3 Distribution Functionalization

The number of distribution asset and expense functions is summarized in Table 3.

Table 3: Functionalization methodology used for distribution assets and expenses		
Methodology	Number of Utilities	Percent of Utilities
10-11	2*	20
8-9	2	20
6-7	2	20
4-5	4	40
Totals	**10**	

5.1.4 Customer Care Functionalization

The customer care category of functions includes assets and expenses associated with providing service to individual customers from the overall shared network. Customer care functions typically include assets and expenses related to the service line, meter and meter reading, billing and collecting, and customer services.

Unlike the standardized labeling of generation, transmission, and distribution, this category of functions has different names across utilities. Alternate names include the customer service and facilities function or retail services function.

Some utilities include this function within the distribution function. The demarcation between the distribution function and customer care function can vary as well. In practice, the customer care functions are classified and allocated by similar methodologies regardless of the overall function in which they are assigned. For example, meter reading costs are classified as customer-related and allocated by a weighted customer count regardless of the function in which it belongs.

The number of customer care asset and expense functions is summarized in Table 4.

Table 4: Functionalization methodology used for customer care assets and expenses		
Methodology	Number of Utilities	Percent of Utilities
6	0*	0
5	1	10
4	4	40
3	3	30
2	2	20
Totals	**10**	

5.2 CLASSIFICATION

5.2.1 GENERATION CLASSIFICATION

There are a variety of methodologies used in the utility industry to classify generation between demand and energy related. The methodologies range from classifying all generation as energy related to classifying all generation as demand related; however, most classifying a portion of the costs as demand and the balance as energy related reflecting that a utility's fleet must accommodate both the peak demand and the annual energy requirement of its customers. The choice of specific methodology should reflect the utility's circumstances.

One common approach is the *Average and Excess* method which classifies generation assets and costs using factors that combine each class's average demands over the test period with its non-coincident peak demands. The average component in this methodology is based on the ratio of each class's average demand to its peak demand. The excess demand is the difference between the class non-coincident peak and the average demand.

In the *Equivalent Peaker* method, generation assets and costs are notionally separated into those deemed to serve peak demands and those that are deemed to be incurred to provide energy. The peaker assets and costs are allocated on a demand basis and the remaining assets and costs, deemed to be energy related, are allocated on an energy basis. The peaker assets and costs are the generation assets and costs of the units used to satisfy system peak demand.

In the *Peak and Average* method, a combination of the class contribution to 12 CP and class contribution to average energy usage is used to allocate generation.

The *Base and Peak* method is based on the concept that a peak kilowatt hour costs more than an off-peak kilowatt hour and that the extra costs should be borne by customers that impose the additional costs. Demand related generation costs are allocated the same as in the Equivalent Peaker method. The difference is in the allocation of energy related generation costs that are allocated to customer classes in proportion to peak energy use instead of total energy use.

The Judgmental Energy Weighting method recognizes that energy is an important factor in generation costs and judgment is used in determining the energy weighting. The NARUC manual uses as an example of judgment the peak and average allocator that adds together each class's contribution to system peak demand and its average demand.

SaskPower adopted the Average and Excess method following Elenchus recommendations in its 2017 Review of Cost Allocation and Rate Design Methodologies report.

The methodology used to classify generation assets and expenses are summarized in Table 5.

Table 5: Classification methodology used for generation assets and expenses

Methodology	Number of Utilities	Percent of Utilities
Set by regulation	1	10
System Load Factor	4*	40
100% demand	1	10
3 CP Peak and Average	1	10
Fixed and Variable	1	10
NA	2	20
Totals	**10**	

5.2.1.1 HYDROELECTRIC

Utilities appear to favour the load factor approach to classify hydroelectric generation. Four Canadian utilities surveyed used this method. Other methodologies used by utilities for classifying some hydroelectric generation assets and expenses to energy are based on the:

- purpose of hydroelectric generation, base or peaking;
- ratio of energy produced in an average year compared to extreme year; and/or
- ratio between hydroelectric capacity factor and total system capacity factor.

Based on the review, the percentages of demand related classification of hydroelectric generation costs are summarized in Table 6.

Table 6: Classification of Hydroelectric generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	2	20
70 - 90	0	0
50 - 70	1	10
35 - 50	3	30
Below 35	1*	10
NA	3	30
Totals	**10**	

5.2.1.2 Base Load Steam

The percentages of demand related classification of base load steam generation (coal, oil, or gas) costs are summarized in Table 7.

Table 7: Classification of Base Load Steam generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	0	0
50 - 70	0	0
35 - 50	3	30
Below 35	0*	0
NA	4	40
Totals	**10**	

5.2.1.3 Combustion Turbine

The percentages of demand related classification of combustion turbine generation costs are summarized in Table 8.

Table 8: Classification of combustion turbine generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0*	0
NA	5	50
Totals	**10**	

5.2.2 TRANSMISSION CLASSIFICATION

The percentages of demand related transmission costs are summarized in Table 9.

Table 9: Classification of transmission costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	6*	60
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0	0
NA	2	20
Totals	**10**	

Transmission costs are usually classified as 100% demand related since transmission capacity is planned to accommodate the maximum system demand. Transmission includes the operation of the grid at different voltages as a single function that transports power from generating stations to the distribution system. Transmission also provides reliability to the electricity system by connecting multiple generation sources.

Transmission may be considered an extension of generation when it is connecting remote generators to the main grid. In this case, it may be classified into demand and energy in the same proportion as the generation it is connecting.

5.2.3 Sub-Transmission Classification

Some utilities may have an additional asset and expense function, sub-transmission system, which connects the transmission system to the distribution system. The definition of sub-transmission depends on the definition of Transmission. If Transmission assets are defined as 115kV and above, then 69 kV assets would be defined as Sub-transmission. In Ontario where Transmission is defined as assets above 50 kV, Sub-transmission is usually defined as 27.6 kV and 44 kV.

Sub-transmission assets and expenses are usually classified in the same proportion as the transmission system. The percentage of demand related costs for sub-transmission costs are summarized in Table 10.

Table 10: Classification of Sub-transmission costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	7*	70
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0	0
NA	1	10
Totals	**10**	

5.2.4 Distribution Classification

Distribution assets connect the transmission assets to customers. Assets that are close to the transmission system tend to be classified in a manner similar to the transmission assets. Distribution assets that are closer to the customer connections tend to be classified in a manner that is more reflective of other customer-related costs. For example, meter assets and costs are classified as 100% customer related, since they must be incurred regardless of how much power the customer consumes.

Distribution costs are incurred for the overall system to reach each customer, to meet the peak demands of customers, and to provide the necessary connection and metering equipment of each customer. To determine what proportion of distribution costs are customer related and what proportion are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

The Minimum System method calculates the proportion of distribution asset costs that are customer-related by taking the ratio of the costs of the smallest distribution assets being used by the utility, e.g., shortest poles, to the costs of all similar assets, e.g., all poles. This process is used to determine the customer components for transformers and line conductors. A common critique of this method is that the customer-related portion of the distribution system can carry some electricity, therefore, some demand related costs would be included in the customer component.

The Zero Intercept method calculates the customer-related component of a distribution asset type by plotting a graph of the unit costs of different sized similar assets and using the value at the zero intercept in the graph to represent to customer component of the asset costs. A common critique of this method is that a utility may not have enough data to plot a proper graph, or in some instances may result in a negative value at zero intercept. The classification methods used for line and transformers are shown in Table 11.

Table 11: Classification Method for Distribution Lines and Transformers

Method	Number of Utilities	Percent of Utilities
Minimum System	3*	30
Zero Intercept	0	0
Both Minimum and Zero Intercept	3	30
Other	3	30
Judgment 50/50	1	10
Totals	**10**	

The proportion of distribution stations costs classified as demand related is shown in Table 12.

Table 12: Classification of Distribution Substation costs to demand

Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	9*	90
NA	1	10
Totals	**10**	

The proportion of Primary Lines costs classified as demand related is shown in Table 13.

Table 13: Classification of Primary Lines costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	4*	40
70 - 90	2	20
50 - 70	3	30
35 - 50	0	0
NA	1	10
Totals	**10**	

The proportion of Distribution Transformer costs classified as demand related is shown in Table 14.

Table 14: Classification of Distribution Transformers costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	4	40
70 - 90	2	20
50 - 70	2*	20
35 - 50	1	10
NA	1	10
Totals	**10**	

The proportion of Line Transformer costs classified as demand related is shown in Table 15.

Table 15: Classification of Line Transformers costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	3	30
50 - 70	2*	20
35 - 50	1	10
NA	1	10
Totals	**10**	

The proportion of Secondary Line costs classified as demand related is shown in Table 16.

Table 16: Classification of Secondary Line costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	2	20
50 - 70	4	40
35 - 50	0	0
Below 35	1*	10
Totals	**10**	

The proportion of Services costs classified as customer related is shown in Table 17.

Table 17: Classification of Services costs to customer		
Percent Classified as customer	Number of Utilities	Percent of Utilities
100	10*	100
Totals	**10**	

The proportion of Meter costs classified as customer related is shown in Table 18.

Table 18: Classification of Meter costs to customer		
Percent Classified as customer	Number of Utilities	Percent of Utilities
100	10*	100
Totals	**10**	

5.3 Allocation

5.3.1 Generation and Transmission Allocators

1 Coincident Peak Method

The 1 CP allocation method allocates demand related costs to each customer class in proportion to the contribution of that customer class to the utility's maximum system peak. This method assumes that system capacity requirements are determined by the maximum demand imposed by customers on the system.

The advantage of this method is that it reflects cost causality assuming peak demand is in fact the sole driver of the costs allocated in this manner. Customers that impose peak costs on the system are responsible for those costs.

The disadvantage of this method is that customers that do not use the system at the time of the system peak or can reduce their consumption during the peak could end up using the system for free, or not paying their fair share of costs. For example, Streetlighting may not be allocated any costs if the peak occurs in the daytime. Another disadvantage is that if there are major system changes and the peak shifts to a different time, it could result in significant changes to class allocation factors over time, possibly causing rate instability.

12 Coincident Peak Method

The 12 CP method is like the 1 CP method but instead of using only one value for the year, it is based on each month's maximum peak. This method assumes that each monthly peak is important and not just the single annual peak.

The advantage of this method is that it addresses the disadvantage of the 1 CP method by reducing or eliminating entirely the possibility of using the system for free. The disadvantage of this method is that if the system had seasonal characteristics, using only one value for each month may not track costs properly.

Various Coincident Peak Variations

Variations to the 1 CP and 12 CP methods are methods that use a subset of highest demand months. Common variations are the 2 CP, 3 CP or 4 CP. The subset of months could be predefined as the months that typically have the highest demands or could use actual highest demands. This method is more stable than that 1 CP method but there could be instability if the peak demand months fluctuate, particularly between winter and summer months.

Another variation is that the coincident peak value may not necessarily be one per month, but could be for example, the highest 5 coincident peak values regardless of when they occur in the year.

1 Non-Coincident Peak Method

The 1 Class Non-Coincident peak method is based on the maximum demand by customer class, regardless of when they occur. Generally, the maximum demands by customer classes occur at different times and do not coincide with the system peak (maximum system demand). A ratio is developed by customer class based on the class maximum demand compared to the sum of all classes' maximum demands. This method is used to reflect cost causality for assets that are the closest to the customer or serve only similar type of customers.

12-Non-Coincident Peak

The 12 NCP allocation method is like the 1 NCP method, but instead of using just one maximum demand for the year, 12 monthly values are used. The ratios of class maximum demand to the sum of each class maximum demands are calculated for each month.

The allocation method for generation demand related costs is shown in Table 19.

Table 19: Allocation Method for Generation Demand Costs

Method	Number of Utilities	Percent of Utilities
1 CP	2	20
2 CP	0*	0
3 CP	2	20
4 CP	2	20
12 CP	1	10
Highest 300 Hours	1	10
NA	2	20
Totals	**10**	

The allocation method for transmission demand related costs is shown in Table 20.

Table 20: Allocation Method for Transmission Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 CP	4	40
2 CP	0*	0
3 CP	1	10
4 CP	1	10
12 CP	1	10
Other	1	10
NA	2	20
Totals	**10**	

The allocation method for sub-transmission demand related costs is shown in Table 21.

Table 21: Allocation Method for Sub-transmission Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 CP	5	50
2 CP	0*	0
3 CP	1	10
4 CP	2	20
Other	1	10
NA	1	10
Totals	**10**	

5.3.2 INTERRUPTIBLE LOAD

Interruptible load reflects a type of service that is curtailed at the time of system maximum demand or other emergencies. Because of the possibility of curtailment, customers served under this condition pay less for electricity than customers supplied on a firm basis. Usually, the amount of the discount the customer receives is tied to the savings to the utility of not building peak capacity to serve the customer. Having this type of service allows for better utilization of the electricity system.

SaskPower has implemented a demand response program[5] that is based on the same principle as interruptible rates, better utilization of the electricity system in return for a discount. In the program, at times of capacity constraints, customers participating in the program that shift load receive financial compensation.

SaskPower accounts for the costs of the demand response program under Purchased Power. This treatment is acceptable since in the absence of the program, the utility would have to supply the shifted demand by purchasing the power from external sources.

5.3.3 Distribution Costs Allocators

Demand

The demand allocation methods for distribution costs are related to the proximity of the distribution asset to the end-use customer. Distribution assets that are further away from the customer and closer to the sub-transmission or transmission system are allocated to customer classes based on coincident demand allocators. The closer the distribution assets are to the customers, then the demand allocation method would reflect the customer class's maximum demand, that is, non-coincident maximum demand.

Customer

Distribution costs that do not vary with customer consumption are classified as customer related and are allocated to customer classes based on number of customers by class or based on weighted number of customers. The weights are related to the type of assets or costs being considered and reflect cost causality. For example, meter reading assets and costs are weighted by the number of times the meter is read by customer class, e.g., monthly, by-monthly, and the relative cost of reading different types of meters.

[5] https://www.saskpower.com/power-savings-and-programs/business/programs/demand-response-program

The allocation method for distribution station demand related costs is shown in Table 22.

Table 22: Allocation Method for Distribution Station Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 NCP	7	70
12 NCP	1	10
Other	1	10
CP	1*	10
Totals	**10**	

The allocation method for distribution Primary Lines demand related costs is shown in Table 23.

Table 23: Allocation Method for Distribution Primary Lines Demand Costs		
Method	**Number of Utilities**	**Percent of Utilities**
1 NCP	7	70
12 NCP	1	10
Other	1	10
CP	1*	10
Totals	**10**	

The allocation method for distribution transformers demand related costs is shown in Table 24.

Table 24: Allocation Method for Distribution Transformers Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 NCP	8*	80
12 NCP	1	10
Other	1	10
Totals	**10**	

The allocation method for distribution secondary lines demand related costs is shown in Table 25.

Table 25: Allocation Method for Distribution Secondary Lines Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 NCP	6	60
12 NCP	1	10
Other	3*	30
Totals	**10**	

The allocation method for distribution station customer costs is shown in Table 26.

Table 26: Allocation Method for Distribution Station Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of Customers	2	20
NA (Stations 100% demand)	8*	80
Totals	**10**	

The allocation method for distribution primary lines customer costs is shown in Table 27.

Table 27: Allocation Method for Distribution Primary Lines Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	5*	50
Other	1	10
NA	4	40
Totals	**10**	

The allocation method for distribution transformer customer costs is shown in Table 28.

Table 28: Allocation Method for Distribution Transformers Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	5*	50
Other	1	10
NA	4	40
Totals	**10**	

The allocation method for distribution secondary line customer costs is shown in Table 29.

Table 29: Allocation Method for Distribution Secondary Lines Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	7*	70
Other	1	10
NA	2	20
Totals	**10**	

The allocation method for services customer costs is shown in Table 30.

Table 30: Allocation Method for Services Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	6	60
Weighted # of customers	4	40
Direct allocation	0*	0
Totals	**10**	

The allocation method for meter costs is shown the Table 31.

Table 31: Allocation Method for Meter Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	4	40
Weighted # of customers	6*	60
Totals	**10**	

5.4 Rate Design

There are various alternatives for rate design being used for different customer classes in the industry. They include:

- End use – Purpose of electricity use, for example residential, commercial, pumping load
- Energy or demand billed – How the customer is being billed: based on energy (kilowatt hours) or demand (kilowatts or kilovolt-amps)
- Density – Where the customer is located: in an urban (high density) area or a rural (low density) area
- Seasonal – When the customer consumes power: year-round or only during a specific season (e.g., summer cottages)
- Voltage of supply – Voltage that the customer is supplied electricity: transmission or high voltage, sub-transmission, primary, secondary, or low voltage

- Size – Amount of demand (kilowatts) or capacity that the customer consumes: e.g., above 50 kW, above 5 MW
- Load factor – Consumption pattern of electricity over time reflecting the costs that this pattern of consumption imposes on the utility, e.g., high load factor customers consume almost the same amount of electricity in all hours
- Quality of supply – Assurances of electricity supply, e.g., firm, interruptible
- Time-of-use – How electricity is charged to the customer, prices may vary by season, (e.g., winter summer), and by period (e.g., peak, off-peak)
- Unmetered – If electricity consumption is uniform then it does not need to be metered e.g., streetlight, cable TV

More than one rate design is usually used by utilities to properly reflect the differences across customer classes and the individual utility's operations.

6 ELENCHUS COMMENTS AND RECOMMENDATIONS

Based on our review of SaskPower's cost allocation methodology, our knowledge of standard practices in other jurisdictions across Canada and our review of the cost allocation practices of other electric utilities undertaken for this report, we are of the view that the methodology currently used by SaskPower in its cost allocation methodology is generally consistent with accepted rate making principles and practices as well as the methodologies commonly used by other electric utilities. Furthermore, SaskPower's cost allocation methodology is consistent with, and is reflective of, SaskPower's operational circumstances.

The following sub-sections outline observations on notable issues and recommended refinements that in our view merit consideration. As noted earlier, cost allocation is more of an art than a science; hence, adoption of any recommended changes to SaskPower's methodology should be dependent on the cost and/or availability of the required data, as well as the potential impact on the complexity of rates and the impact on customers. No changes should be implemented without due consideration and balancing of all the Bonbright principles of rate making as well as SaskPower's objectives and operational circumstances.

As stated in Page 67 of the NARUC manual:

> *Keep in mind that no method is prescribed by regulators to be followed exactly; and agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid*

out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

6.1 REVIEW OF EXISTING RATE DESIGN METHODOLOGY

Elenchus reviewed the current Rates manual used by SaskPower.

SaskPower uses a basic monthly charge and energy charge (¢/kWh) for Residential and energy billed small commercial customers. This is a common practice among utilities for these types of customer classes given the type of meters typically used to measure their electricity consumption.

Diesel supplied customers have a monthly charge and an inclining energy rate that reflects the significantly higher costs of diesel generation required to produce electricity for customers not connected to the electricity grid due to their remote location.

Farms and larger commercial customers with demand meters have a basic charge, a demand rate for consumption above 50 kVa/month and an energy rate that declines once the demand rates is applied.

Larger customers, (power standard, resellers), have a monthly charge, a demand charge, and an energy charge.

6.1.1 COINCIDENT PEAK ALLOCATION METHODOLOGY

SaskPower previously applied an adjustment in its rate design to take into consideration the relationship between load factor and coincidence factors. This adjustment is known as the coincident peak allocation methodology, or the Bary correction. High load factor customers tend to have higher coincidence factors, that is, the higher the load factor for a customer the higher the chances that it will consume electricity at the time of the utility's maximum system demand which is the driver of capacity-related costs.

The standard ratemaking practice aligns fixed charges with fixed costs, demand charges with demand-related costs, and energy charges with energy-related costs.[6] This alignment is considered to provide an appropriate price signal to reflect the incremental costs caused by incremental demand or consumption.

The adjustment previously made by SaskPower shifted a portion of demand-related costs to be recovered through energy charges. At a class level the revenue collected from customers before and after the rate design adjustment remained unchanged so there

[6] Due to the high cost of demand meters it is not practical to have demand charges for smaller volume classes, such as the residential class. Demand-related costs are instead recovered through the fixed monthly charge and/or variable energy charges.

were no inter-class equity issues. From a cost causality perspective, rates set with this adjustment were considered more equitable as it resulted in customers within a class with different load profiles having a revenue to cost ratio that is closer to the customer class average revenue-to-cost ratio than if no adjustment was made to the rates.

However, this adjustment distorted the price signal for energy and demand charges. Higher energy prices created a false price signal for customers to self-generate. Customers that self-generated to avoid energy charges were avoiding not only energy-related costs but also the demand-related costs that were shifted to the energy charge. The demand-related costs caused by customers with self-generation were not recovered from those customers, shifting costs to customers that didn't cause those costs.

This price signal also encouraged grid defection. A significant portion of SaskPower's revenue requirement is associated with fixed or semi-fixed costs that are shared among customers. Defection from the grid will cause those costs to be recovered from a smaller number of customers and lower level of billing determinants (kWh or kVA) resulting in higher bills for the remaining customers. This is a growing concern as self-generating technologies and Distributed Energy Resources (DERs) become more cost effective.

Starting in 2022, this adjustment is gradually being phased out of SaskPower's rate design over time. Elenchus supports this change to SaskPower's rate design methodology.

6.1.2 Time-of-Use Rates

Time-of-use rates have been implemented by some utilities to send a more refined price signal to customers on the costs of consuming electricity at different times of the day, days of the week and seasons through the year. Generation costs are normally the largest component of electricity supply costs and reducing generation costs could provide benefits to the utility and consumers in the form of lower utility costs and therefore lower customer bills. The intent of time-of-use rates is that if customers have the proper price signals with enough incentives to modify behaviour, they will change their consumption patterns and reduce their usage during high-cost periods even when consumption is increased during low cost periods. Reducing consumption in high-cost periods allows the utility to reduce its total costs by reducing the requirement for peak capacity or for purchasing expensive imported power at times of high demand.

Implementing time-of-use rates (TOU rates) requires that the proper infrastructure be in place in the form of "smart" meters that are capable of recording, for example, hourly consumption. Implementing TOU rates also requires meter reading and billing systems capabilities that enable the processing of the required data. The assets and software required to implement time-of-use rates are such that it may be justifiable in locations with very high electricity supply costs during peak periods.

However, TOU rates may not be economic for the utility or its customers in instances where the differential in marginal costs between high and low demand periods is small. For example, where the capacity and fuel cost savings are not large enough to offset the infrastructure costs required to implement time-of-use rates, introducing TOU rates may not be cost effective. As with any other investment, a decision on implementation should be based on a sound business case. The business case for TOU rates can be approached either by considering only the utility's generation and network costs and savings, or by also building in external costs, such as environmental and health benefits. The goal of TOU rates should not be to benefit "free riders" who have low consumption in high-priced periods in any case, but to shift demand and reduce the average cost of power.

For time-of-use to achieve the goal of changing consumption patterns, the differential in prices between high and low-cost periods must provide sufficient incentive for customers to modify their behaviour without resulting in undue sacrifices. It also should reflect the utility's characteristics that would result in savings because of lower consumption during high-cost periods. In particular, if the marginal cost of supply is essentially the same in all hours of the year, shifting demand will not reduce the utility's total costs or customer bills.

In SaskPower's case, it is Elenchus' understanding that a reduction in customers' electricity consumption during high-cost periods would not result in cost savings to SaskPower. Currently natural gas is the fuel used at the margin to supply capacity at times of high electricity demands and if consumption is shifted to periods of low electricity consumption, natural gas is still the fuel that is used at the margin to supply power during periods of low electricity consumption.

Time-of-use for transmission costs may make sense in instances when there is capacity constraint in the transmission system, but transmission costs are not a large component of customers' total electricity bill. Time differentiated transmission rates may be implemented to complement time differentiated generation rates and thus provide a consistent price signal to customers.

Distribution costs are for the most part fixed for a utility and are not dependent on the customer's electricity consumption, therefore time differentiated distribution rates may not be appropriate from a cost causality perspective, although they may be implemented to provide a consistent price signal to customers in support of time differentiated generation rates.

It is Elenchus' understanding that SaskPower operates an electricity system that already has a high load factor of 75% and is projected to become even higher because of the addition of new load that is for the most part flat consumption load. Operating a system with high load factor limits the expected benefits of implementing time differentiated rates to encourage load shifting. If circumstances change in Saskatchewan, for example marginal costs change, or the fuel type used at the margin providing peak capacity changes, consideration should be given to implementing time-of-use rates as one possible demand management tool available to the utility, instead of building new capacity to meet increased demand for electricity.

6.2 Main Functionalization, Classification and Allocation Methodologies

6.2.1 Functionalization of Generation Assets and Expenses

The appropriate functionalization method groups assets and expenses that are incurred for similar purposes. The selection of functions should strike a balance between providing a sufficient division of assets and expenses without adding unnecessary complexity by adding many functions that are classified in the same manner. The appropriate selection of functions should also consider the practicality of having functions that align with line items within financial statements.

Generation Plants

SaskPower has nine generation functions: Load, Losses, Scheduling & Dispatch, Regulation & Frequency Control, Spinning Reserve, Supplementary Reserve, Planning Reserve, Reactive Supply, and Grants in Lieu of Taxes. The Load function includes all sources of SaskPower's generation.

Utilities typically functionalize generation into different types of generation. The same classification factors are often applied to each generation function; however, this could evolve over time with changes to load dispatch. The carbon charge provides an economic incentive to dispatch more lower-emitting generation sources, thereby shifting more costs to peak generation.

Elenchus recommends for SaskPower to consider breaking out its Load function into separate functions in the future. This will not impact the classification or allocation of generation assets or expenses in the short term but will provide SaskPower with the flexibility to change generation classification methodologies in the future.

System Operator Functions

Scheduling & Dispatch and Regulation & Frequency are typically considered system operator functions. In deregulated jurisdictions, such as Ontario and Alberta, the system operator is an entity separate from any regulated utility. In vertically integrated utilities like SaskPower, these functions are typically grouped with transmission functions. Elenchus recommends moving the Scheduling & Dispatch and Regulation & Frequency functions to transmission.

Other Generation Functions

Of SaskPower's nine generation functions, four functions serve similar purposes and are classified and allocated on the same basis. These four functions are Spinning Reserve, Supplementary Reserve, Planning Reserve, and Reactive Supply. Elenchus notes other utilities do not functionalize these functions as distinct functions in class cost allocation methodologies. SaskPower advised that this breakout is used for its Open Access Transmission Tariff (OATT) cost allocation and rate design process.

These functions could be combined or absorbed into the load function for consistency with other utilities, however, there is no compelling reason to stray from current practice in its class cost allocation model other than simplification.

Losses

SaskPower has separate Load and Losses generation functions. No other utility reviewed by Elenchus has a separate Losses function. To functionalize losses, SaskPower attributes some total energy costs to losses in proportion to the share of losses within the generation requirement. Likewise, a share of total demand costs is attributed to demand losses in proportion to the share of demand losses within peak demands. This attribution of generation costs provides a rate base and expense associated with losses.

The Load function is allocated based on energy and demand without losses. The Losses function is allocated based on the losses of each class. These allocations differ because classes served at higher voltages have lower losses.

Other utilities do not implement the initial step of separating load-related rate base and expenses and losses-related rate base and expenses.

Other functions that are classified as energy and/or demand are allocated based on losses-adjusted energy and losses-adjusted demand, so Load is the only function allocated based on energy and demand without losses.

Though uncommon, Elenchus does not see a compelling reason for SaskPower to change its methodology. A change to the conventional methodology used by other utilities would not result in a change in the costs allocated to each rate class.

6.2.2 CLASSIFICATION OF GENERATION ASSETS AND EXPENSES

Different methodologies are generally used to classify generation costs from a utility's own generation system compared to the classification of purchased generation from external sources. This is the case for SaskPower.

SaskPower's Generation Fleet

SaskPower uses the Average and Excess method to classify generation expenses. This methodology, as described in the NARUC Manual, page 49, is a commonly used and accepted methodology to classify generation assets and expenses. The method uses factors that combine classes' average demand and non-coincident peak demands. SaskPower used rate codes information instead of customer class information to develop the necessary customer consumption data.

The Average and Excess method reflects the use of the system by SaskPower's customers and apportions assets and costs based on how customers use the system.

6.2.3 Classification of Transmission Assets and Expenses

SaskPower classifies transmission assets and expenses as 100% demand-related and this is an accepted approach in the industry. As seen in the survey results six out of eight utilities surveyed classify transmission assets and expenses as 100% demand related.

Elenchus supports SaskPower classification of transmission assets and expenses.

6.2.4 Classification of Distribution Assets and Expenses

Lines and transformers are the largest cost items in the distribution of electricity to customers. Six of the ten utilities surveyed use the minimum system to classify some component of the distribution system as customer related.

Currently SaskPower uses in its cost allocation study survey results to classify distribution costs between demand and customer-related for lines and transformers. SaskPower tried to use the Zero Intercept method but was unable to obtain the necessary supporting data. SaskPower collected the necessary data to calculate the results of classifying distribution assets and expenses based on the minimum system approach.

The Minimum System method is used to classify distribution lines and distribution transformer assets and expenses between demand and customer related. The data required for the Minimum System method reflects the current minimum size distribution transformers and distribution lines used by the utility in serving customers and uses replacement assets and expenses to estimate the value of the minimum system. The ratio of the cost of the minimum system to the cost of replacing all existing distribution transformers and distribution lines would represent the customer component percentage.

6.3 *Survey of Classification and Allocation Methodologies*

The results of the utility survey conducted by Elenchus has been discussed in section 5 above and more details are provided in Appendix B below.

6.3.1 Minimum System Method

Elenchus reviewed SaskPower application of the Minimum System method for its distribution lines and distribution transformers.

The customer related proportion of lines and transformers is usually higher for low density utilities. SaskPower has very low density, approximately 3 customers per kilometers and the lower the customer density the higher the customer related component for distribution lines and distribution transformers. This is an expected result as assets are being utilized by fewer customers and distribution assets are required regardless of how much electricity customers consume.

As an example, in Ontario, the Ontario Energy Board uses the following default values for the customer component of lines and transformers based on the electricity distributor density:

- If density is less than 30 customers per kM of lines, customer component is 60% for lines and transformers
- If density is between 30 and 60 customers per kM of lines, customer component is 40% for lines and transformers
- If density is higher than 60 customers per kM, customers component is 35% for lines and 30% for transformers

SaskPower's minimum system study produces the following results:

- Distribution lines - 68.5% customer related, 31.5% demand related
- Distribution transformers – 35.5% customer related, 64.5% demand related

These results are marginally different than the percentages currently used by SaskPower in its cost allocation study. Distribution lines are classified as 70% customer related and 30% demand related and distribution transformers are classified 35% customer related and 65% demand related. Some utilities surveyed by Elenchus use minimum system and similar studies as checks of the reasonableness of rounded classification splits, however, it is Elenchus' view that the precise figures should be used if they are available.

The results of the minimum system study should be implemented by SaskPower in its cost allocation study considering the impact of the change on customers' revenue requirement and related revenue to cost ratios. A multi-year implementation may be necessary to mitigate customers' bill impact, however, Elenchus anticipates this change will have a minimal impact on revenue to cost ratios.

To address the concern that the minimum system can carry some electricity and that some demand related costs would be included in the customer component an adjustment is made to take into consideration the demand that can be supplied through the minimum system. The adjustment is called the Peak Load Carrying Capacity (PLCC).

The PLCC adjustment determines the theoretical capacity of the minimum system, that is, the capacity of the smallest distribution asset. The capacity of the smallest distribution asset is divided by the number of customers served by the distribution system and an average minimum system capacity per customer is calculated. This average minimum capacity is multiplied by the number of customers in each rate class and the corresponding amount is deducted from the peak demand for that rate class to derive the adjusted peak demand. The adjusted peak demand is used to allocate demand related distribution assets and costs.

SaskPower uses the PLCC adjustment to classify distribution lines and transformers to demand related and customer related. Elenchus supports this methodology as the PLCC adjustment attributes the costs of a minimum system as customer related and the costs incurred to meet capacity requirements as demand related more precisely than a methodology without this adjustment.

6.3.2 Winter/Summer Allocation (2 CP)

In jurisdictions where electricity markets have been opened to competition, such as Ontario and Alberta, generation costs are bid to the system market operator by generators and are not classified and allocated to customers using a traditional cost allocation methodology. Transmission companies in these competitive markets are also usually not allowed to own generation assets. This is the situation in which two of the utilities surveyed operate.

The survey results show that the method used to allocate demand-related generation assets and costs by five out of eight utilities involves using more than one coincident peak as the allocator: three, four and twelve coincident peak values are used.

For transmission demand-related assets and costs four out of eight utilities use the one coincident peak method as allocator and the other four utilities use more than one coincident peak as an allocator: three, four or twelve peaks are used.

SaskPower uses the 2 CP allocation method to allocate generation, transmission and primary distribution lines demand related assets and costs to customer classes to reflect cost causality. For secondary distribution lines demand related assets and costs SaskPower uses the one class non-coincident peak method.

Based on information from SaskPower staff the capacity of network equipment in the summer can be reduced by as much as between 20% to 30% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, for some facilities, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities. Additionally, SaskPower staff informed Elenchus that urban areas served by SaskPower tend to have maximum demands in the summer, while rural areas tend to have maximum demands in the winter. This fact further supports the concept of using two CP as the allocation method for demand related assets and expenses.

6.3.3 Coincident and Non-Coincident Peak Allocators

SaskPower currently uses 5 years of historical data to develop the demand and energy allocators. The number of years of historical data to be used varies significantly across jurisdictions. Based on the survey of utilities, the number of years of historical data used can be: 1, 3, 5, 8, 10, or 22 years.

Elenchus is of the view that as a minimum 3 years of data should be used to eliminate unusual events that may occur in one year and to provide more representative load profiles. Elenchus opinion is that SaskPower's use of 5 years of historical data is appropriate.

6.3.4 Functionalization of Overhead Costs

In general, utilities classify overhead assets and expenses in the same proportion as other assets and expenses. Some overhead assets or expenses are classified as all other assets or expenses, while some overhead assets or expenses that are more specific and dedicated to a specific function are classified following those specific functions. For example, head office expenses would be classified as all other expenses, vehicles used for building and maintaining lines would be classified between Transmission and Distribution functions based on Transmission and Distribution line assets. Using this approach ensures that the effect of the classification of overhead costs is neutral and it does not alter the overall classification of assets and costs. Similarly, the allocation of overhead assets and expenses is based on the allocation of other assets and expenses to customer classes. It is Elenchus' understanding that SaskPower's classification and allocation of overhead costs follows the same approach, it is classified and allocated in the same manner as other assets and expenses.

Elenchus endorses this approach. There is a very loose causal relationship to support the allocation of overhead costs to customer classes. There is significant merit in allocating these costs in direct proportion to all other costs, where there is a more directly discernible causal relationship.

Based on Elenchus experience this same approach is applied by utilities in other jurisdictions.

6.3.5 Carbon Pricing

As of 2019 SaskPower is required to pay the Federal Carbon Tax on consumption of its carbon-emitting fuels.

SaskPower has included the Federal Carbon Charge as a separate line item on customer bills. The carbon charge is the same for all kWh consumed, aside from a class-specific adjustment for losses. This methodology treats the carbon charge as a pass-through item that is separate from SaskPower's revenue requirement and is not included within the cost allocation model. This methodology provides a transparent line item for the carbon charge to be included on customer bills.

Alternatively, the carbon charge expense could be included in the revenue requirement and flow through the cost allocation model in which case it would be functionalized either as its own generation function or included as part of the fuel function because the cost is caused by fuel consumption. The expense would be classified as energy-related in the same way fuel costs are classified and allocated by losses-adjusted energy consumption.

The cost allocation methodology described above produces the same result as the outside-the-model losses-adjusted calculation, aside from minor differences due to class deviations from 1.00 revenue to cost ratios. Given the equivalency of the results and additional transparency, the methodology used by SaskPower is appropriate.

7 Stakeholders Comments

Stakeholders provided the following comments to Elenchus.

[NTD: To be added for final draft.]

APPENDIX A: SASKPOWER COST ALLOCATION METHODOLOGY DOCUMENTATION

The information below was extracted from a document titled: "2021 Fiscal Base Embedded Cost of Service Study" prepared by SaskPower.

Functionalization

1. *Rate Base Items*

1.1 - Plant in Service & Accumulated Depreciation

- **SaskPower Generation, Transmission, and Distribution:**

All of the rate base accounts are functionalized on the basis of the plant designation; generation plant is functionalized entirely to the generation function; transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for Wind Projects are included within SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.

- **Coal Reserves:**

SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

- **Shand Greenhouse:**

The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.

- **Purchased Power Agreements:**

The assets associated with Purchased Power Agreements are functionalized to generation.

- **Meters:**

Meters are included in the meters sub-function within distribution.

- **General Plant - Unused Land:**

The functionalization and sub-functionalization of unused land is done using Operations, Maintenance and Administration expense (OM&A).

- **General Plant – Buildings:**

The functionalization of the SaskPower head office building is based on floor space analysis. All other buildings are functionalized using the square footage attached to each cost centre. The asset values for buildings are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense. 2015 Base Embedded Cost of Service Results

 General Plant - Office Furniture & Equipment:
The functionalization and sub-functionalization are the same as for buildings.

 General Plant - Vehicles & Equipment:
The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit center. The asset values for vehicles and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

 General Plant - Computer Development & Equipment:
The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application-by-application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

 General Plant - Communication, Protection & Control Equipment:
Communication, Protection & Control Equipment is functionalized to generation, transmission, distribution, and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

 General Plant - Tools & Equipment:
The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

1.2 - Allowance for Working Capital
 The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working is calculated as 12.5% of the sum of Operations, Maintenance and Administration (OM&A) expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.3 - Inventories
 SaskPower accounting records summarizes inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within

the generation, transmission and distribution functions using Operations, Maintenance and Administration expense (OM&A).

1.4 - Other Assets

 Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

 Natural gas / coal related:

Functionalized to generation.

 Employee related:

Functionalized using head count by Business Unit / Support Group.

 Insurance expense related:

Functionalized using information provided from SaskPower's Risk management staff.

 Miscellaneous:

Prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

2. **Revenue Requirement Items**

A summary of the functionalization methodology for expense plus the return on rate base items is provided below:

2.1 - Fuel Expense SaskPower Units

 The fuel expense for SaskPower units is functionalized 100% to generation.

2.2 - Purchased Power and Import

 The purchased power expense is functionalized 100% to generation.

2.3 - Export & Net Electricity Trading Revenue

 Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.4 - Operating, Maintenance & Administration (OM&A) Expense

 Power Production Business Unit:

The OM&A expenses for the Power Production Business Unit and Purchased Power Agreements (PPA's) are functionalized to generation.

 Transmission & Distribution Business Unit:

A small amount of the Transmission and Distribution Business Unit's OM&A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the OM&A expense for the Business Unit is split to transmission and distribution using cost centre reports.

- Transmission OM&A is sub-functionalized by separating transmission OM&A expense into line and station related. The line related OM&A is sub-functionalized to main grid, 138 & 72 kV radials using line lengths by sub-function. The station related OM&A expense is sub-functionalized using station assets plant in service by sub-function.

- Distribution OM&A is functionalized to distribution and customer services using a combination of staff input and detailed cost centre OM&A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions.

- The Electrical and Gas inspections OM&A was transferred to General Council/Land in 2014 but is still functionalized to Customer Services as previously done. Similarly, Metering Services OM&A was moved from Customer Services to Transmission & Distribution in 2013 but is still functionalized to Customer Services.

- **Customer Services Business Unit:**
The OM&A expense for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre Operation, Maintenance and Administration (OM&A) reports.

- **Customer Services - Bad Debt Expense:**
The bad debt expense is assigned to the customer collections sub-function with the Customer Services function.

- **President / Board:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.

- **Corporate & Financial Services:**
Functionalized based on employee head count by Business Unit and Support Group.

- **Corporate & Financial Services – Insurance Premiums & Insurable Losses:**
Functionalized based on Breakdown from SaskPower Risk Management & Insurance department staff.

- **Resource Planning:**
Resource Planning was previously called Planning and Regulatory Affairs (PERA). Resource Planning is made up of 3 cost Centers: Planning and Regulatory Affairs, Environment, and Shand Greenhouse. The Planning cost center is assigned to functions and sub-functions based on the functionalization and sub-functionalization of

the sum of the OM&A expense for the three Business Units and Support Groups. The Environment cost center moved to Resource Planning from Human Resources in 2015 and is allocated based on an employee analysis which was done by SaskPower Environment department staff. The Shand Greenhouse moved to Resource Planning from Power Production in 2015 and is functionalized to Generation.

- **People & Processes - General Council / Land:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Electrical and Gas inspections OM&A was moved to General Council/Land from Transmission and Distribution in 2014 and is functionalized to Customer Services.

- **Clean Coal Project:**
The OM&A expense for the Clean Coal Project is functionalized to Generation.

- **People & Processes – Safety:**
Is functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the OM&A sub-functionalization within each function.

- **People & Processes - Corporate Information & Technology (CI & T):**
CI&T operations, maintenance and administration expense is separated into personal computer related and Business Unit related. The personal computer related is functionalized using employee headcount. The Business Unit related is functionalized using information from the cost centre report. Sub-functionalization is completed using OM&A within each function.

- **People & Processes - Human Resources:**
Functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function.

- **Commercial & Industrial Operations:**
Commercial & Industrial Operations is a newly formed department made up of 4 cost centers: Customer Relations, Coal Combustion Products, Fuel Supply and NorthPoint. The Customer Relations cost center was previously reported in Customer Services and continues to be functionalized to Customer Service. Coal Combustion was previously reported in the Power Production business unit and continues to be functionalized to Generation. The Fuel Supply cost center was previously reported in Resource Planning and continues to be functionalized to Generation. NorthPoint previously was reported in Operations and continues to be functionalized to Generation.

- **Procurement & Supply Chain**
Procurement & Supply chain is made up of 3 cost centers: Supply Chain, Properties & Shared Services, and Contract Management. Supply Chain and Properties & Shared Services are functionalized based on the employee head count by Business Unit and

then sub-functionalized using the OM&A sub-functionalization within each function. Contract Management is functionalized to Generation. The Logistics area was moved to Procurement & Supply Chain in 2015 from Distribution, however, based on Logistics' close relation to Distribution; their OM&A is still being calculated and functionalized within Distribution.

2.5 - Depreciation & Depletion
 The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.6 - Corporate Capital Tax
 Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.7 - Grants in Lieu of Taxes
 Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.8 – Miscellaneous Tax
 The miscellaneous tax expenses have been grouped into the following categories using cost center reports:

 Power production related:
Functionalized to generation.

 Fuel supply related:
Functionalized to generation.

 Gas & electric inspections related:
Functionalized to customer services.

 Vehicles and equipment related:
Functionalized using the vehicles and equipment plant functionalization as reported in Section 1.1.

 Buildings related:
Functionalized using the buildings plant functionalization as reported in Section 1.1.

 Corporate related:
Functionalized using total OM&A expense.

2.9 - Other Income
 Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.

 Customer services payment income:

Assigned to the billing, customer accounts and collections sub-functions within customer services.

- **Meter reading income:**
Assigned to the meter reading sub-function within the customer services function.

- **Gas & electric inspections income:**
Assigned to the Customer Service sub-function within the customer services function.

- **Transmission related income:**
Assigned to sub-functions within the transmission function using transmission OM&A expense.

- **Distribution related income:**
Assigned to sub-functions within the distribution function using distribution OM&A expense.

- **Clean Coal Test Facility Revenue:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **Clean Coal Project Credits:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **CO2 Sales & Penalties:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **Miscellaneous Other Income:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.

- **Customer Contribution Revenue**
As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.

- **Green power premium:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **NorthPoint:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **Flyash & Wind Power Sales:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **Consulting & Contracting Services:**

Assigned to functions and sub-functions based on the functionalization and sub functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.

2.10 - Return on Rate Base

 The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

STEP 3: CLASSIFICATION

The classification process splits the functionalized costs into the parameters of service, which are:
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission and distribution systems.
Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.
Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

A discussion of the classification of each of the functionalized costs is as follows:

 Generation:
SaskPower generation rate base and expense is classified as either demand or energy related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method, based on the NARUC Electric Utility Cost Allocation manual. This approach uses the ratio of the unit cost of new peaking capacity to the new cost of base load capacity for different generation types to classify rate base and depreciation to demand and energy.

The assets and expenses associated with Purchased Power Agreements (PPA's) are classified to demand and energy using the capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The expenses and income associated with fly-ash sales (now called Coal Combustion Products) are classified as energy related.

The classification of all wind power rate base and expense are classified 80% to energy based on the results of SaskPower's most recent planning study regarding the capacity value of wind generation. This is a change from previous years, when SaskPower planning staff did not attach any capacity value to wind generation.

- **Coal Reserves:**
SaskPower coal reserves are classified energy related.

- **Shand Greenhouse:**
The Shand Greenhouse assets, OM&A and depreciation expenses are classified using the classification of all SaskPower generation.

- **NorthPoint:**
The OM&A expense and other revenue associated with NorthPoint are classified 100% to energy related.

- **Transmission:**
Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% to demand.

- **Distribution:**
Substations are classified 100% to demand-related cost. Three phase feeders are classified 100% to demand-related cost. Both urban and rural single-phase primary lines are classified 65% to demand-related and 35% to customer-related cost. Line transformers are classified 70% to demand-related and 30% to customer-related cost based upon industry data. All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as customer-related.

- **Customer:**
Customer related costs are classified 100% to customer.

The results of the functionalization and classification (or functional classification) of rate base, expense, return on rate base, and revenue requirement are summarized in ***Schedules 2.00 through to 2.36***.

STEP 4: ALLOCATION

Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated.

- Urban Residential
- Rural Residential
- Farms
- Urban Commercial
- Rural Commercial

- Power - Published Rates
- Power - Contract Rates
- Oilfields
- Streetlights
- Reseller

An explanation of the allocation process by function is as follows:

- **Generation:**

The energy related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand related rate base and expenses are allocated by the 2CP (coincident peak) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

- **Transmission:**

All of the transmission functions are classified as demand and are allocated using the 2CP (coincident peak) method as aforementioned.

- **Distribution:**

The *demand functions* within distribution use a combination of the 2CP method and the Non-Coincident Peak (NCP) method. The NCP method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occur, to the sum of all the class peaks, similarly determined. Only the *transformers'* function uses the NCP methodology; all other functions use the 2CP methodology.

The *customer functions* within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight related rate base and expenses are allocated directly to streetlights.

- **Customer Services:**

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

- **Customer Contributions:**

These contributions are allocated back directly to the customer classes which made the contribution.

- **Load Data**

Customer load data is obtained for each class from the best available sources. Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The results for the customer types in each of these classes are then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.
Power Class loads were analyzed based on hourly meter readings from actual customer's interval metered sites.

- **Loss Study**

The purpose of a loss study is to properly quantify and assign to the appropriate customer class the electrical energy and demand losses in the various segments of the system. The starting point is the total energy loss in GWh, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

APPENDIX B UTILITIES SURVEYED

Canadian

BC Hydro

ATCO Electric

Manitoba Hydro

Hydro One Networks Inc.[7]

Hydro Quebec

Newfoundland Power

New Brunswick Power

Nova Scotia Power

US Utilities

Montana-Dakota Utilities

Georgia Power

[7] In Ontario the electricity market was deregulated in April 1999. OPG generates electricity and Hydro One transmits and distributes electricity

	Method to classify Generation assets and expenses
BC Hydro	55% demand, 45% energy using a system load factor approach
ATCO	NA
Manitoba Hydro	Eight-year average system load factor 39.9% demand
Hydro One	NA
Hydro Quebec	Utilization factor during 300 hours - 69.4% demand
NL Power	System load factor 45.7% demand
NB Power	# CP and Average 49.2% demand
NS Power	Hydro investments are demand Other demand related based on system load factor - overall 31.4% demand
Georgia Power	100% demand
Montana-Dakota Utilities	Net plant 100% demand, O&M 33% demand

	Hydroelectric	Baseload Steam	Combustion Turbine	Transmission	Sub-transmission
BC Hydro	55% demand/45% energy	100% demand	100% demand	100% demand	100% demand
ATCO	NA	NA	NA	AESO bill into demand/customer	30% to 35%
Manitoba Hydro	39.9% demand	39.9% demand	39.9% demand	100% demand	100% demand
Hydro One	NA	NA	NA	100% demand	100% demand
Hydro Quebec	NA	NA	NA	Rate base 100% demand, Expenses 24.9% demand	100% demand
NL Power	System load factor 45.7% demand	NA	NA	100% demand	100% demand
NB Power	49.2% demand	49.2% demand	49.2% demand	100% demand	100% demand
NS Power	100% demand	31.4% demand	100% demand	Currently 46.2% demand	Currently 46.2% demand
Georgia Power	100% demand	100% demand	100% demand	100% demand	100% demand
Montana-Dakota Utilities	100% of net plant is demand related and 33% of O&M is demand related	100% of net plant is demand related and 33% of O&M is demand related	100% of net plant is demand related and 33% of O&M is demand related	100% demand	100% demand

	Distribution Substations	Primary Lines	Distribution Transformers	Line Transformers	Secondary Lines	Services Fixed costs
BC Hydro	100% demand	100% demand	50% demand/50% customer	50% demand/50% customer	50% demand/50% customer	50% demand/50% customer
ATCO	100% demand	100% demand	40% to 60% demand (currently 47.6%)	40% to 60% demand (currently 47.6%)	30% to 35% demand	100% customer
Manitoba Hydro	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer
Hydro One	100% demand	52.2% demand	38.1% demand	38.1% demand related	52.2% demand related	100% customer
Hydro Quebec	100% demand	100% demand	100% demand	79.8% demand	79.8% demand	100% customer
NL Power	100% demand	63% demand	72% demand	72% demand	63% demand	100% customer
NB Power	100% demand	50% demand	75% demand	75% demand	50% demand	100% customer
NS power	100% demand	62.5% demand	100% demand	100% demand	17.6% demand	100% customer
Georgia Power	100% demand	82% demand	100% demand	75% demand	75% demand	100% customer
Montana-Dakota Utilities	100% demand	100% demand	100% demand	20% Demand	100% demand	100% customer

	Meters	Method used to determine distribution customer related	Method used to allocate generation demand costs	Method used to allocate transmission demand costs	Method used to allocate sub-transmission demand costs	Method used to allocate distribution stations demand costs
BC Hydro	100% customer	Zero Intercept for transformers. Minimum System for secondary	4CP	4CP	4CP	Class NCP
ATCO	100% customer	Average of Zero intercept and Minimum system	NA	Allocated POD Capacity Demand and AEIS CP Summary Demand	EDLA study (Energy, Demand Loss Analysis) [Annual POD NCP Demand]	EDLA study (Annual POD NCP Demand)
Manitoba Hydro	100% customer	PUB order 100% demand	1 CP on top 50 winter hours	1 CP on top 50 winter hours	1 CP on top 50 winter hours	Class NCP
Hydro One	100% customer	Minimum System	NA	12 CP	12 CP	CP and NCP
Hydro Quebec	100% customer	Minimum System	Highest 300 hours	1CP	1CP	1NCP
NL Power	100% customer	Minimum System for lines, Zero Intercept for transformers	1 CP	1 CP	1 CP	NCP
NB Power	100% customer	Historical	3 CP	1 CP	1 CP	12 NCP
NS Power	100% customer	Judgement 50/50	3 winter CP	3 winter CP	3 winter CP	1 NCP
Georgia Power	100% customer	Zero intercept	12 CP	12 CP	4 CP	4-CP
Montana-Dakota Utilities	100% customer	Minimum System	4 Coincident Peak 75% Demand/25% Energy	12 CP	CP	CP

	Method used to allocate distribution primary lines demand costs	Method used to allocate distribution transformers demand costs	Method used to allocate distribution secondary lines demand costs	Method used to allocate distribution stations customer costs	Method used to allocate distribution primary lines customer costs	Method used to allocate distribution transformers customer costs
BC Hydro	NCP class	NCP class	NCP class	# of customers	# of customers	# of customers
ATCO	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	Weighted Property Plant & Equipment (Transformers)	Weighted Property Plant & Equipment (Poles & Conductor)	NA (100% demand)	NA (100% demand)	Property Plant & Equipment (Transformers) weightings depending on customer counts
Manitoba Hydro	Class NCP	Class NCP	Class NCP	NA (100% demand)	NA (100% demand)	NA (100% demand)
Hydro One	NCP	NCP	NCP	NA (100% demand)	Customer count	Customer count
Hydro Quebec	1NCP	1NCP	1NCP	# of customers	# of customers	# of customers
NL Power	NCP	NCP	NCP	NA (100% demand)	Equal Weighting	Equal Weighting
NB Power	12 NCP	12 NCP	12 NCP	N/A	# of customers	# of customers
NS Power	1 NCP	1 NCP	1 NCP	NA (100% demand)	Weighted # of customer	NA (100% demand)
Georgia Power	NCP	NCP	Average # of Customers	NA (100% demand)	Average # of Customers	NA (100% demand)
Montana-Dakota Utilities	NCP	NCP	NCP	NA (100% demand)	NA (100% demand)	NA (100% demand)

	Method used to allocate distribution secondary lines customer costs	Method used to allocate services customer costs	Method used to allocate Meter customer costs
BC Hydro	# of customers	# of customers	# of customers
ATCO	Property Plant & Equipment (Poles & Conductors) weightings depending on customer counts	Weighted Customer Count	Weighted Customer Count
Manitoba Hydro	NA (100% demand)	Weighted Customer Count	Weighted Customer Count
Hydro One	Customer Count Secondary	Weighted Customer Count	Weighted Customer Count
Hydro Quebec	# of customers	Weighted # of customers	Weighted # of customers
NL Power	Equal Weighting	Based on typical costs to provide drops to customers within each class	Based on typical costs to provide drops to customers within each class
NB Power	# of customers	Weighted # of customers	Weighted # of customers
NS power	Weighted number of customers	Weighted number of customers	Weighted # of customers
Georgia Power	Average # of customers	Average # of customers	Average # of customers
Montana-Dakota Utilities	# of customers	Number of customers	Weighted # of customers

APPENDIX C ELENCHUS TEAM QUALIFICATIONS

[NTD: To be added for final version of the report.]