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Review of Cost Allocation and Rate Design Methodologies

A Report Prepared by
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Prepared for SaskPower

30 June 2017

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EXECUTIVE SUMMARY

SaskPower retained Elenchus Research Associates (Elenchus) in order to:

1. Review its existing cost allocation methodology,
2. Review its existing rate design methodology,
3. Identify main classification and allocation methodologies,
4. Compare the SaskPower methodology with practices in Canada and the US with particular emphasis on Canadian electric utilities,
5. Review specific items identified by the Saskatchewan Rate Review Panel (SRRP):
    (a) Equivalent Peaker method
    (b) Minimum system method
    (c) Customer class consolidation
    (d) Winter & summer allocation (2 CP)
    (e) Coincident and non-coincident peak allocators
    (f) Functionalization of overhead costs
    (g) Impact of Demand Response programs
6. Make recommendations to SaskPower on possible improvements to the cost allocation methodology, and
7. Make recommendations for possible changes to its approach to rate design for SaskPower's consideration.

Elenchus, with the assistance of SaskPower staff, conducted a review of SaskPower's methodologies, undertook a survey of methodologies used by utilities with respect to cost allocation and rate design and participated in two public meetings in Regina presenting progress report on its review and recommendations for consideration by SaskPower.

Elenchus found that the methodologies used in SaskPower's Cost of Service models are generally accepted methodologies to Functionalize, Classify and Allocate shared assets and expenses to customer classes. Elenchus did not uncover inherent bias in any of the methodologies used that would favour one customer class over another class.

The rate design methodologies followed by SaskPower follow standard industry practices as seen by Elenchus in other jurisdictions.

Elenchus is recommending three changes in SaskPower's cost allocation methodologies:

1. Average and Excess method for classifying generation assets and expenses,
2. Minimum System with PLCC adjustment to classify distribution lines and transformers and
3. MDD definition for calculating annual non-coincident peak by rate class.

The impact of these three recommendations on SaskPower's Cost Allocation study is shown in the following two tables.

Table 1: Impact on R:RR Ratios of Elenchus Recommendations

Customer Class	R/RR Ratio (Existing)	R/RR Ratio (Revised)	Change
Residential	0.96	0.97	0.01
Farm	0.96	0.97	0.01
Commercial	1.03	1.03	0.00
Power Class	1.03	1.01	-0.02
Oilfields	1.02	1.03	0.01
Streetlights	0.86	0.78	-0.08
Reseller	0.93	0.94	0.01
Total	1.00	1.00	0.00

Table 2: Impact on Revenue Requirement ($M) of Elenchus Recommendations

Customer Class	$ M (Existing)	$ M (Revised)	Change
Residential	509.2	505.4	-3.81
Farms	164.9	164.7	-0.18
Total Commercial	420.9	418.6	-2.33
Total Power	593.9	600.7	6.86
Oilfields	324.6	323.3	-1.23
Streetlights	17.5	19.2	1.72
Reseller	96.8	95.8	-1.04
Total	2,127.7	2,127.7	0.00

1 OVERVIEW

SaskPower retained Elenchus Research Associates (Elenchus) in order to:

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   (g) Impact of Demand Response programs

6. Make recommendations to SaskPower on possible improvements to the cost allocation methodology, and
7. Make recommendations for possible changes to its approach to rate design for SaskPower's consideration.

This report consists of 7 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's approach to rate making.

Section 4 provides an overview of SaskPower's cost allocation methodology, recognizing that this methodology is fully documented in "2015 Base Embedded Cost of Service", dated October 14, 2016, 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 survey 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 impacts of Elenchus' recommendations.

Section 8 includes the comments received from stakeholders on Elenchus' review and recommendations in this report and provides Elenchus' responses to the comments.

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

Appendix B provides a list of the utilities surveyed and the responses to the cost allocation survey.

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

Appendix D includes the questions and answers to SIECA's letter to SaskPower dated May 26, 2017.

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

[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.

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 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) 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 revenue requirement illustrates to what extent the class is paying for their share of costs imposed on the utility. A revenue to revenue requirement ratio of 1, or above 1, means that the class is paying their fair share of costs, or even more than their fair share. A revenue to revenue requirement ratio below 1 means that the class is not paying for their fair share of costs.

Since the allocation of shared costs amongst various customer classes cannot be done in a precisely accurate way and parameters or allocators are used to split shared costs, in many jurisdictions a range of revenue to revenue requirement ratio is accepted as reflecting the fair allocation of costs to customer classes instead of striving to achieve a revenue to revenue requirement 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 revenue requirement 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.*

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[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.

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) 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 of 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 following sub-sections set out our interpretation of SaskPower's objectives.

3.1 MEETING REVENUE REQUIREMENT

Meeting SaskPower's revenue requirement implies that customer rates should be set so as 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 criteria. 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] 2015 Base Embedded Cost of Service Study, October 14, 2016

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:

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

Transmission

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

Distribution

i. Area Substations
ii. Distribution Mains
iii. Urban Laterals
iv. Rural Laterals

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[4] Ibid

v. Transformers
vi. Services
vii. Instrument Transformers
viii. Meters
ix. Streetlights
x. Customer Contributions

Customer Service

i. Metering Services
ii. Meter Reading
iii. Billing and Customer Accounts
iv. Customer Collecting
v. Customer Service
vi. Marketing & Sales

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 "2015 Base Embedded Cost of Service Study".

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 Equivalent Peaker method. This method is based on the ratio of the unit cost of new peaking capacity to the new cost of base load capacity by generation types.

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 65% demand-related and 35% customer-related. Line transformers are classified 70% demand-related and 30% to customer-related based on industry data.

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 "2015 Base Embedded Cost of Service Study".

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 and the one class non-coincident peak method.

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 customer by customer class for other assets or costs (e.g., where average per customer costs differ across classes, such as meter costs).

4.3.1 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.

- Urban Residential
- Rural Residential
- Farms
- Urban Commercial
- Rural 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 "2015 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 "2015 Base Embedded Cost of Service Study".

5 SURVEY OF COST ALLOCATION METHODOLOGIES

Elenchus conducted a survey of 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.

Classification of assets and expenses and allocation methodologies were surveyed and the results of the survey are included in this report and more details of the survey responses and utility statistics 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.

5.1 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 classify a portion of the costs as demand related 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 judgmental energy weighting the peak and average allocator that adds together each class’ contribution to system peak demand and its average demand.

SaskPower uses the Equivalent Peaker method outlined in the NARUC Manual by taking the ratio of the unit costs of new peaking capacity to the unit cost of new base load capacity to determine the demand related portion of generation by fuel type.

Based on the responses to the Elenchus survey the methodology used to classify generation assets and expenses are summarized in Table 3.

Table 3: Classification Methodology Used for Generation Assets and Expenses

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

5.1.1 HYDROELECTRIC

Based on the survey results, Canadian 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
- ratio between hydroelectric capacity factor and total system capacity factor

Based on the responses to the survey the percentages of demand related classification of hydroelectric generation costs are summarized in Table 4.

Table 4: Classification of Hydroelectric Generation Costs to Demand

Percent Classified as Demand	**Number of Respondents**	**Percent of Respondents**
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	

5.1.2 Base load steam

Based on the responses to the survey the percentages of demand related classification of base load steam generation (coal, oil, or gas) costs are summarized in Table 5.

Table 5: Classification of Base Load Steam Generation Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	3	30
35 - 50	3	30
NA	4	40
Totals	10	

5.1.3 Base Load Combined Cycle

Based on the responses to the survey the percentages of demand related classification of base load combined cycle generation costs are summarized in Table 6.

Table 6: Classification of Base Load Combined Cycle Generation Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	3	30
35 - 50	2	20
Below 35	0	0
NA	5	50
Totals	10	

5.1.4 Combustion Turbine

Based on the responses to the survey the percentages of demand related classification of combustion turbine generation costs are summarized in Table 7.

Table 7: Classification of Combustion Turbine Generation Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	4	40
35 - 50	2	20
Below 35	0	0
NA	4	40
Totals	10	

5.2 TRANSMISSION CLASSIFICATION

Based on the responses to the survey the percentages of demand related transmission costs are summarized in Table 8.

Table 8: Classification of Transmission Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	6	60
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 these cases, it may be classified into demand and energy in the same proportion as the generation it is connecting.

5.3 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, or as in the case of one distributor it includes voltages between 13.8 kV and below 50 kV.

Sub-transmission assets and expenses are usually classified in the same proportion as the transmission system. Based on the responses to the survey the percentage of demand related costs for sub-transmission costs are summarized in Table 9.

Table 9: Classification of Sub-Transmission Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	7	70
35 - 50	2	20
Below 35	0	0
NA	1	10
Totals	10	

5.4 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.

In order 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 is able to 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 size 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. Based on the responses to the survey the classification methods used for line and transformers are shown in Table 10.

Table 10: Classification Method for Distribution Lines and Transformers

Method	Number of Respondents	Percent of Respondents
Minimum System	2	20
Zero Intercept	0	0
Both Minimum and Zero Intercept	3	30
Other	4	40
Judgment 50/50	1	10
Totals	10	

Based on the responses to the survey the proportion of distribution stations costs classified as demand related is shown in Table 11.

Table 11: Classification of Distribution Substation Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	10	100
Totals	10	

Based on the responses to the survey the proportion of Primary Lines costs classified as demand related is shown in Table 12.

Table 12: Classification of Primary Lines Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	5	50
70 - 90	2	20
50 - 70	3	30
Totals	10	

Based on the responses to the survey the proportion of Distribution Transformer costs classified as demand related is shown in Table 13.

Table 13: Classification of Distribution Transformers Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	5	50
70 - 90	2	20
50 - 70	3	30
Totals	10	

Based on the responses to the survey the proportion of Line Transformer costs classified as demand related is shown in Table 14.

Table 14: Classification of Line Transformers Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	3	30
70 - 90	4	40
50 - 70	2	20
35 - 50	1	10
Totals	10	

Based on the responses to the survey the proportion of Secondary Line costs classified as demand related is shown in Table 15.

Table 15: Classification of Secondary Line Costs to Demand

Percent Classified as Demand	Number of Respondents	Percent of Respondents
90 - 100	3	30
70 - 90	2	20
50 - 70	4	40
Below 35	1	10
Totals	10	

Based on the responses to the survey the proportion of Services costs classified as customer related is shown in Table 16.

Table 16: Classification of Services Costs to Customer

Percent Classified as Customer	Number of Respondents	Percent of Respondents
100	10	100
Totals	10	

Based on the responses to the survey the proportion of Meter costs classified as customer related is shown in Table 17.

Table 17: Classification of Meter Costs to Customer

Percent Classified as Customer	Number of Respondents	Percent of Respondents
100	10	100
Totals	10	

5.5 ALLOCATION

5.5.1 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 is based on the assumption 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 when allocating transmission demand related assets and expenses 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. Another disadvantage is that if there are major system changes and the peak shifts to a different time, it could result in changes to class allocation factors, possibly causing rate instability.

12 Coincident Peak Method

The 12 CP method is similar to 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

A variation on the 1 CP and 12 CP methods is that more than 1 and less than 12 values are used in the derivation of the coincident peak allocator.

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

1 Class 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.

It is not appropriate for upstream assets such as transmission and generation since it does not take into account the benefits derived through diversity and that not all customers' maximum demand occurs at the same time, allowing for the assets to be built to serve less than the sum of all customers maximum demand.

12-Non-Coincident Peak

The 12 NCP allocation method is similar to 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.

Based on the responses to the survey the allocation method for generation demand related costs is shown in Table 18.

Table 18: Allocation Method for Generation Demand Costs

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

Based on the responses to the survey the allocation method for transmission demand related costs is shown in Table 19.

Table 19: Allocation Method for Transmission Demand Costs

Method	Number of Respondents	Percent of Respondents
1 CP	4	40
3 CP	1	10
4 CP	1	10
12 CP	1	10
Other	1	10
NA	2	20
Totals	10	

Based on the responses to the survey the allocation method for sub-transmission demand related costs is shown in Table 20.

Table 20: Allocation Method for Sub-Transmission Demand Costs

Method	Number of Respondents	Percent of Respondents
1 CP	5	50
3 CP	1	10
4 CP	2	20
12 CP	1	10
Other	1	10
Totals	10	

5.5.2 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 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] http://www.saskpower.com/efficiency-programs-and-tips/business-programs-and-offers/demand-response-program/

5.5.3 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' 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 would be weighted by the number of times the meter is read by customer class, e.g. monthly, by-monthly.

Based on the responses to the survey the allocation method for distribution station demand related costs is shown in Table 21.

Table 21: Allocation Method for Distribution Station Demand Costs

Method	Number of Respondents	Percent of Respondents
1 NCP	7	70
12 NCP	1	10
Other	1	10
CP	1	10
Totals	10	

Based on the responses to the survey the allocation method for distribution Primary Lines demand related costs is shown in Table 22.

<u>Table 22: Allocation Method for Distribution Primary Lines Demand Costs</u>

Method	Number of Respondents	Percent of Respondents
1 NCP	8	80
12 NCP	1	10
Other	1	10
Totals	10	

Based on the responses to the survey the allocation method for distribution transformers demand related costs is shown in Table 23.

<u>Table 23: Allocation Method for Distribution Transformers Demand Costs</u>

Method	Number of Respondents	Percent of Respondents
1 NCP	8	80
12 NCP	1	10
Other	1	10
Totals	10	

Based on the responses to the survey the allocation method for distribution secondary lines demand related costs is shown in Table 24.

Table 24: Allocation Method for Distribution Secondary Lines Demand Costs

Method	Number of Respondents	Percent of Respondents
1 NCP	7	700
12 NCP	1	10
Other	2	20
Totals	10	

Based on the responses to the survey the allocation method for distribution station customer costs is shown in Table 25.

Table 25: Allocation Method for Distribution Station Customer Costs

Method	Number of Respondents	Percent of Respondents
# of Customers	2	20
NA (Stations 100% demand)	8	80
Totals	10	

Based on the responses to the survey the allocation method for distribution primary lines customer costs is shown in Table 26.

Table 26: Allocation Method for Distribution Primary Lines Customer Costs

Method	Number of Respondents	Percent of Respondents
# of customers	5	50
Weighted # of customers	1	10
Other	1	10
NA	3	30
Totals	10	

Based on the responses to the survey the allocation method for distribution transformer customer costs is shown in Table 27.

Table 27: Allocation Method for Distribution Transformers Customer Costs

Method	Number of Respondents	Percent of Respondents
# of customers	5	50
Other	1	10
NA	4	40
Totals	10	

Based on the responses to the survey the allocation method for distribution secondary line customer costs is shown in Table 28.

Table 28: Allocation Method for Distribution Secondary Lines Customer Costs

Method	Number of Respondents	Percent of Respondents
# of customers	7	70
Other	1	10
NA	2	20
Totals	10	

Based on the responses to the survey the allocation method for services customer costs is shown in Table 29.

Table 29: Allocation Method for Services Customer Costs

Method	Number of Respondents	Percent of Respondents
# of customers	3	30
Weighted # of customers	7	70
Totals	10	

Based on the responses to the survey the allocation method for meter costs is shown the Table 30.

Table 30: Allocation Method for Meter Customer Costs

Method	Number of Respondents	Percent of Respondents
# of customers	2	20
Weighted # of customers	8	80
Totals	10	

5.6 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)
- 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 in order 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 survey 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 of 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 COST OF SERVICE METHODOLOGY

Based on the results of the survey, seven out of eight utilities classify hydroelectric generation as at least 35% demand related. The eighth utility classifies hydroelectric generation as 34% demand related. In SaskPower's case, using the Peaker method results in 19% of hydroelectric generation being classified as demand related. Elenchus therefore notes that the proportion of demand-related costs used by SaskPower is below the range compared to other utilities that classify a portion of hydroelectric generation as demand related.

For baseload steam generation, combined cycle generation, and combustion turbine generation six utilities surveyed classify at least 35% as demand related, compared to SaskPower's baseload steam generation from conventional coal value of 52% demand related, retrofit coal generation value of 19% demand related, combined cycle value of 82% demand related and peaking generation of 100% demand related.

The survey results and Elenchus experience do not suggest that there is a consensus in the industry of what is considered a right or wrong methodology. The various classification methodologies used in the industry are the result of utilities' past practices, utilities' circumstances and are determined through the regulatory process as providing appropriate results that reflect the utility's local circumstances.

Options to consider for classifying SaskPower's generation assets and expenses is addressed below in section 6.3.1.

6.2 Review of Existing Rate Design Methodology

Elenchus reviewed the current Rates manual used by SaskPower.

SaskPower uses a basic monthly charge and energy charge (¢/kW.h) for residential, small farm and 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.

SaskPower applies an adjustment in its rate design to take into consideration the relationship between load factor and coincidence factors. 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. It is considered more equitable that energy rates are increased and demand rates are decreased by applying this adjustment. At a class level the revenue collected from customers before and after the rate design adjustment remains unchanged. This adjustment, which is referred to as the coincident peak allocation method by SaskPower, is also referred to as the Bary correction named after Constantine Bary, results in customers within a class with different load profiles having a revenue to revenue requirement ratio that is closer to the customer class average revenue to revenue requirement ratio than if no adjustment is made to the rates.

Based on Elenchus' experience the adjustment made by SaskPower is not widely applied in utilities, but it is considered more equitable.

The rate design methodology used by SaskPower is consistent with the methodology used by other utilities and Elenchus supports SaskPower's methodology. The rate design methodology is consistent with SaskPower's principles for cost allocation and rate design.

During the presentation made by Elenchus on March 30, 2017 on progress in the review of SaskPower's Cost Allocation and Rate Design methodologies, Meadow Lake Mechanical Pulp Inc. raised an issue with respect to SaskPower's 138 kV rate. Elenchus opinion and recommendation on this issue is presented in Section 7 of this report.

6.2.1 TIME-OF-USE RATES

Time-of-use rates have been implemented by some utilities in order 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, customers would change consumption patterns and reduce consumption 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 justified. 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.

In order for time-of-use to achieve the goal of changing consumption patterns, the differential in prices between high and low cost periods has to provide sufficient incentive for customers to modify their behaviour without resulting in undue sacrifices. Is also should reflect the utility's characteristics that would result in savings as a result 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 due to SaskPower's high system load factor, which is related to a high proportion of constant industrial demand, and SaskPower's ability to utilize its installed hydro generation capacity during peak demand periods, natural gas is typically always on the margin (i.e. the generation that is being turned on/off to meet demand). Shifting consumption will have little effect as natural gas will remain on the margin.

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 and is projected to become even higher as a result 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 to be considered, instead of building new capacity to meet increased demand for electricity.

During the presentation made by Elenchus on March 30, 2017 on progress in the review of SaskPower's Cost Allocation and Rate Design methodologies, Meadow Lake Mechanical Pulp Inc. raised an issue with respect to SaskPower's time of use rates. In response, Elenchus conducted a survey of jurisdictions that have some form of time of use rates and Elenchus opinion and recommendation on this issue is presented on Section 7 of this report.

Elenchus understands that there is only one customer currently on time-of-use rates. Given SaskPower's circumstances with respect to its high load factor and the fuel at the margin being the same fuel in the peak and off-peak periods, there is no cost justification for SaskPower to offer time-of-use rates. As part of its rate consolidation plan, SaskPower may want to consider eliminating offering time of use rates as a rate option to its customers and grandfather the only existing customers currently taking advantage of time of use rates so that only this customer can continue to be on time of use rates.

6.3 MAIN CLASSIFICATION AND ALLOCATION METHODOLOGIES

6.3.1 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

In the past, SaskPower has relied on the Equivalent Peaker method of classifying generation assets and costs between demand and energy related assets and expense. This approach is becoming impractical for several reasons. First, standard costing data for fossil plants is no longer available. As a result, historical data must be used although it is not reflective of current costs and technologies that are used by, or available to SaskPower. Furthermore, environmental regulations required SaskPower to invest significant capital in coal retrofitting measures that impact the results of applying SaskPower's current Equivalent Peaker method. The resulting change in the calculated demand-energy split is not a reasonable reflection of cost drivers for SaskPower's generation assets and expenses.

Consistent with the concept of a fully integrated utility, when evaluating generation classification methodologies, Elenchus did not differentiate between existing and new generation when evaluating SaskPower's Functionalization, Categorization and Allocation of generation assets and expenses in the cost allocation study.

Elenchus did not consider the process and criteria SaskPower uses to decide when to invest in new generation. System planning is the methodology used to determine the required capacity and energy that would have to be accommodated reliably in the future as well as the least cost option for meeting those requirements.

Elenchus experience is that in a cost allocation study, the process and criteria used by a utility to invest in new generation is not relevant in order to determine the methodology to apportion generation assets and expenses to customer classes.

Elenchus recommends a change in the classification methodology used by SaskPower[6].

Elenchus reviewed the methods typically used by other integrated electric utilities in Canada and 2 US based utilities to identify the approach that would be the most appropriate for the SaskPower system. As shown in Section 5.1, Table 1, four out of eight utilities use a methodology based on system load factor (Average and Excess) to classify generation assets and expenses.

Two alternative methodologies were explored by Elenchus with assistance from SaskPower staff: Average and Excess and 2 CP and Average. Both alternatives are load based options.

The Average and Excess method, 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 in order to develop the necessary customer consumption data.

Customer classes are comprised of rate codes. Rate Codes are the rates charged to a specific group of customers for their electrical usage. Examples include the Power Class rates (i.e., E22, E23, E24, E25, E82, E83, E84, & E85). Together these individual rate codes, when combined, make up the Power – Published customer class. Another

[6] In 2015, New Brunswick Power conducted a review of its cost allocation method (NB EUB Matter 271) that revisited its use of the Equivalent Peaker Methodology. Based on the evidence of two experts, Concentric Energy Advisers and Elenchus, NB Power determined that it was appropriate to discontinue its use of the Equivalent Peaker Method, in part because it was producing unstable results. The NB Energy and Utilities Board accepted this recommendation.

example would be the Residential class that is made up of rate codes E01, E02, E03, & E04. SaskPower conducted its analysis at the rate code level and then combined them into their appropriate customer classes to summarize the results.

The 2 CP and Average method determines the demand related percentage based on the 2 CP maximum demand and the average demand. The energy related portion is the remaining percentage.

The alternative Average and Excess method produced a 78.3% of energy related generation costs. This is not surprising as SaskPower has a relatively high system load factor above 70%. The 2 CP and Average method produced a proportion of energy related costs of 43.9%.

Based on costs causality principles and reflecting SaskPower's high load factor system the percentage of energy related generation costs should be higher than currently used in SaskPower's cost allocation study.

Elenchus recommends that as an alternative to the Equivalent Peaker method to classify generation assets and costs, SaskPower should implement the Average and Excess method.

Elenchus considered SaskPower's customer consumption profile in determining the generation classification methodology recommended.

A classification methodology based on customer consumption provides more stable classification results over time than a generation classification method based on generation assets, whose initial purpose may change over time, reflecting change in operational circumstances and/or Government policy.

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.

The result on SaskPower's cost allocation methodology of using the Average and Excess method is 78.3% energy related and 21.7% demand related.

The impact on revenue to revenue requirement ratios of the Average and Excess method compared to the current Equivalent Peaker method is shown in the table below

Table 31: Impact of Changing from Equivalent Peaker to Average & Excess or Judgemental Energy Weightings

10 Class of Service	Revenue to Revenue Requirement Ratios 2015 Base 2CP		
	Equivalent Peaker (Existing)	Average & Excess	2CP & Average
	Various DMD/ ENG %'s	21.7 % DMD 78.3% ENG	56.1% DMD 43.9% ENG
Urban Residential	0.97	0.98	0.97
Rural Residential	0.94	0.95	0.93
Total Residential	0.96	0.98	0.96
Farms	0.96	0.97	0.96
Urban Commercial	1.03	1.03	1.03
Rural Commercial	1.03	1.03	1.03
Total Commercial	1.03	1.03	1.03
Power - Published Rates	1.05	1.04	1.06
Power - Contract Rates	0.94	0.95	0.94
Total Power	1.03	1.01	1.03
Oilfields	1.02	1.02	1.03
Streetlights	0.86	0.85	0.86
Reseller	0.93	0.94	0.92
Total	1.00	1.00	1.00

Power Purchase Agreements

Power Purchase Agreements are classified into demand and energy based on the capacity and energy payments for each plant. Natural gas price forecast is a major component of these payments and could significantly affect the amount and type of payments. Based on discussions with SaskPower staff, historical natural gas prices are used for cost allocation purposes.

Elenchus recommends that SaskPower compare the historical natural gas prices used for cost allocation purposes with SaskPower's forecast prices for natural gas and if there is a large difference in prices, SaskPower may want to consider using forecast natural gas prices in order to classify Power Purchase Agreement expenses into demand and energy. This would allow for better data to be used in the cost allocation methodology.

Elenchus understands that the same percentage has been applied to fuel for all Power Purchase Agreement contracts. An alternative being suggested by Elenchus is to use percentage for each Power Purchase Agreement contract to classify payments into demand and energy for fuel costs.

6.3.2 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.

6.3.3 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 survey results in its cost allocation study to classify distribution costs between demand and customer related for lines and transformers. In the past, SaskPower attempted 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.

6.4 SURVEY OF CLASSIFICATION AND ALLOCATION METHODOLOGIES

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

6.5 REVIEW ITEMS IDENTIFIED BY SRRP

6.5.1 EQUIVALENT PEAKER METHOD

Elenchus reviewed SaskPower's application of the Equivalent Peaker method to classify generation assets and expense into demand and energy related and Elenchus is of the view that SaskPower correctly applied the methodology to its generation assets.

Given the discussion above in section 6.3.1, Elenchus recommends that SaskPower consider applying the Average and Excess method to classify generation assets and costs instead of continuing to use the Equivalent Peaker method.

6.5.2 MINIMUM SYSTEM METHOD

Elenchus recommends that SaskPower implement the Minimum System methodology to classify distribution lines and transformers between customer and demand related. This methodology is used by other utilities to classify distribution lines and transformers. The data for this methodology is generally easier to obtain for a utility than the Zero Intercept methodology and would reflect SaskPower's own distribution circumstances instead of relying on the data for other utilities as SaskPower is currently using in classifying some distribution lines and transformers.

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 kilometer 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 30% for lines and 35% 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 different than the percentages currently used by SaskPower in its cost allocation study. The results of the minimum system study should be implemented by SaskPower in its cost allocation study taking into account the impact of the change on customers' revenue requirement and related revenue to revenue requirement ratios. A multi-year implementation may be necessary in order to mitigate customers' bill impact

To address the concern that the minimum system is able to 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.

Elenchus recommends that SaskPower calculate the PLCC of its Minimum System method and implement the results, if it uses the Minimum System method to classify distribution lines and transformers.

6.5.3 Customer Class Consolidation

SaskPower is considering a rate simplification plan in order to reduce the number of rates codes used and to simplify and reduce the number of customer classes.

The number of customer classes in a utility is usually determined by regulation or past utility history. The number of customer classes reflects a balancing act between trying to group customers with similar cost causality characteristics and maintaining a manageable level of different customer classes. The larger the number of customer classes, the better the cost allocation will reflect cost causality characteristics for individual customers, but the more expensive it is to maintain by the utility and the more complicated the regime is for customers. It is inevitable that any grouping of customers results in winners and losers within the group. The trade-off is that the fewer the number of customer classes, the less expensive it is to maintain by the utility and also it is easier to understand by customers and stakeholders.

SaskPower customer classes currently consist of 10 groups, but each customer class has multiple rate codes, making the administration of the multiple rate codes difficult to for customers to understand and a challenge for SaskPower staff.

SaskPower is recommending a two phase approach to simplify its customer classes and rate codes:

Phase 1 will consist of the following measures:

- Combining urban and rural rates together; this will eliminate 6 rate codes,
- Moving Large Oilfield accounts to Standard Power Rates; this will eliminate 6 rate codes,

- Combining streetlight technologies by lumen rating, resulting in the elimination of all current streetlight rate codes and the creation of 5-8 potential lumen ranges for them to be categorized to. This will allow SaskPower to more readily adopt and implement new technologies without having to add more rates to accommodate them, and.
- Combining Power class 138 and 230 kV transmission rates together; this will eliminate 2 rate codes

Phase 2 will examine the following measures:

- Eliminating customer owned transformer General Service rates and implementing transformer credits, and
- Reviewing, and if possible reducing, the number of flat rates.

SaskPower has determined that the expected bill impacts of phase one of its proposed customer class consolidations will be:

- Customers on urban rates will see a slightly higher rate increase and customers on rural rates will see a lower rate increase.
- Moving Large Oilfield Accounts to Standard Power Rates will have no impact on customers.
- Customers on streetlight rate codes that are being eliminated will see small changes in their (higher and lower) streetlight bill.
- Combining Power class 138 and 230 kV transmission rates together will have very little impact as there is very little difference between these two rates.

Elenchus generally supports the consolidation efforts being proposed by SaskPower. The resulting customer classes and reduced number of rate codes should be more manageable for SaskPower staff and easier to understand by SaskPower's customers. The main impediment to customer class consolidation and reduction in rate codes is usually the potential bill impact on affected customers. Based on the analysis conducted by SaskPower, the bill impact to affected customers appears to be reasonable. The proposed customer class consolidation is also consistent with the advice provided to

SaskPower by the consultants retained by SaskPower in the past two reviews of its cost allocation and rate design methodologies.

6.5.4 WINTER/SUMMER ALLOCATION (2 CP)

In jurisdictions where electricity markets have been opened up 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 allocated 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 in order 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 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.

An analysis of the last 10 years of system data (2006-2015) in SaskPower's service territory shows that the ratio of summer to winter maximum demand is 91%. The same data for the last 3 year shows a similar ratio of 91% between summer and winter maximum demand. It is therefore evident that SaskPower is a winter peaking utility. Nevertheless, it is also evident that if the seasonal peak is assessed as a percentage of seasonal capacity, it is the summer peaks that place the greatest demands on the network relative to the actual operating capacity during those peak periods. On this basis, it may be more appropriate to view the summer peaks as the prime driver that causes capacity costs to be incurred, at least for those facilities that are most affected by the higher summer temperatures.

In Ontario, which used to be a winter peaking system, but is now a summer peaking system, the ratio of winter to summer maximum demand forecast by the Independent Electricity System Operator for the 2017 to 2018 period is 97% based on weather normal forecast and 93% based on extreme weather forecast[7]. In Ontario, the allocation factor used by Hydro One Networks (Hydro One Networks has over 95% of transmission capacity in Ontario) to allocate a large portion of its transmission costs, (network costs represent over 60% of Hydro One's Transmission Revenue Requirement), is based on the higher of the monthly coincident demand during the peak period or 85% of the monthly maximum customer demand, also during the peak period.

For Manitoba, the ratio of summer to winter maximum demand is 96%[8]. Manitoba is a winter peaking system. Manitoba Hydro uses the 1 coincident peak allocation method based on highest 50 winter hours for generation and transmission assets.

Based on the results of the survey where many utilities use more than one peak as allocator and taking into consideration the information from SaskPower's system planners, Elenchus continues to support the use of the 2 CP allocator by SaskPower as a demand allocation methodology for generation, transmission and primary distribution

[7] IESO 18 months outlook Jan 2017 - June 2018 p. ii

[8] Enhanced and ERA Adjusted Model of PCOSS14

lines. This allows for seasonal capacity and seasonal demand also to be taken into consideration in the allocation factors.

SaskPower currently uses 5 years of historical data and 3 winter hours and 3 summer hours for each year in order to calculate the winter and summer peaks in the 2 CP methodology for the test year, which is the basis for rate design. The hours used can all be in the same months. SaskPower uses this approach in order to average the results and reduce variability.

Elenchus agrees that using more than one year of data provides a more representative and more stable result. SaskPower is doing this by using 5 years of data. Using 3 winter hours and 3 summer hours to determine seasonal peaks introduces an additional level of averaging and produces a more representative and more stable result.

Based on sensitivity analysis conducted by SaskPower staff, the revenue to revenue requirement ratio does not vary significantly when using the average of the three highest winter and summer hours in calculating the maximum winter and summer peaks. The following tables shows the revenue to revenue requirement ratios for 2015 based on a) the highest winter and summer peak, b) based on the 5 year average of the 3 highest hours of winter and summer peaks, and c) based on the 5 year average of the winter and summer maximum peaks.

1 **Table 32: Revenue to Revenue Requirement Ratios 2015 Data**

Customer class	Single year, winter and summer peaks	5 year average, 3 highest hours winter and summer peaks	5 year average, winter and summer peaks
Residential	0.96	0.96	0.98
Farms	0.96	0.98	0.97
Commercial	1.03	1.02	1.02
Power	1.03	1.02	1.01
Oilfields	1.02	1.03	1.03
Streetlights	0.86	0.86	0.86
Reseller	0.93	0.95	0.96
Total	1.00	1.00	1.00

Comparing the customer classes' revenue to revenue requirement ratios for 2014 and 2015 without the 5-year averaging and without the 3 highest hours show that the results are more variable.

Table 33: Revenue to Revenue Requirement Ratios 2014 - 2015 Data

Customer Class	Single year, winter and summer peaks 2015	Single year, winter and summer peaks 2014
Residential	0.96	0.97
Farms	0.96	0.98
Commercial	1.03	1.06
Power	1.03	1.00
Oilfields	1.02	1.01
Streetlights	0.86	0.92
Reseller	0.93	0.92
Total	1.00	1.00

Elenchus agrees with the use of 5 years of historical data, the exclusion of outliers from historical data, and the use of 3 winter and 3 summer maximum demand hours in order to estimate the 2 CP allocator. The methodology used by SaskPower provides a more representative and more stable result in the cost allocation study.

6.5.5 Coincident and Non-Coincident Peak Allocators

SaskPower currently uses 5 years of historical data in order 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.

In Ontario, for example, the Ontario Energy Board allowed two distributors to use one year worth of smart meter data in order to update the typical hourly class load profile for Residential customers. Elenchus is of the view that as a minimum 3 years of data should be used in order 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.

Elenchus and SaskPower staff reviewed the calculations of non-coincident peak load factors and their use in SaskPower's cost allocation study. Elenchus recommends that the non-coincident peak load factor currently used should be changed and the load factor that should be used in the cost allocation study should be based on the maximum demand of the rate class. This is based on Elenchus experience in other jurisdictions of how non-coincident peak load factors are calculated for a customer class. Currently SaskPower uses each individual customer's maximum demand to calculate the non-coincident peak load factor of the customer class. In SaskPower's load research program, the non-coincident peak load factor is described as:

> *This is the maximum demand of a rate class, regardless of when it occurs, during a specified period. Also known as the Class Maximum Diversified Demand (MDD), it represents the totalized demand of all customers residing within a particular class, not the aggregate of their individual demands.*

The following Table shows the impact on revenue to revenue requirement ratios of using the MDD definition.

Table 34: Revenue to Revenue Requirement Ratios 2015 Data

Customer Class	2015 Base (NCP)	2015 Base (MDD)
Residential	0.96	0.97
Farms	0.96	0.97
Commercial	1.03	1.02
Power	1.03	1.03
Oilfields	1.02	1.01
Streetlights	0.86	0.85
Reseller	0.93	0.93
Total	1.00	1.00

6.5.6 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 OM&A split 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.

6.5.7 IMPACT OF DEMAND RESPONSE PROGRAM

Customer class load profiles are used in cost allocation methodologies to classify and allocated assets and expenses.

Demand response programs implemented by utilities may affect the load profiles of customers and may result in customer classes having a different hourly load profile than in the absence of the programs. For example, if coincident peak allocators are used in cost allocation and the utility implements a demand response program in order to reduce the utility's system peak, it would change the hourly load profile of the participating customers, and therefore the hourly load profile of the customer class that is used in cost allocation methodologies.

Elenchus has been informed that SaskPower has had demand response programs since 2011. One demand response program is for a maximum 4 hour duration with different prior notification periods, while another program can result in 5 to 10 hours of temporary load curtailment. The program provides SaskPower with a list of customers that can be called upon to reduce or shift their electrical use. The programs are described as:

> *Large industrial customers with suitable (or consistent) load characteristics and that are able to reduce their electricity load by a minimum of five megawatts (MW) per event from a single location are eligible for this program.*

Based on data provided by SaskPower staff for the period 2011 to 2016, there was only one occasion when the demand response program was triggered at the time of a system summer peak and this was due to an emergency event when SaskPower was experiencing unit failures and subsequent gas unit de-rates. All other times when the demand response programs were implemented occurred at times other than the winter of summer system peaks.

SaskPower staff informed Elenchus that the anomalous event has been excluded from the 5 years data used for cost allocation purposes. That is, the curtailed load has been added back to the class load profile of the related customer classes for cost allocation purposes.

The demand response program participants are very large customers that have the ability to curtail electricity consumption and provide system relief at times required by the system operator. The participating customers have hourly consumption meters and the change in hourly electricity consumption would be properly recorded and would not need to be estimated for load forecast purposes. Therefore, the load profiles used for cost allocation purposes properly reflect the consumption patterns of customers participating in the demand response programs.

Given that the demand response programs are not being used to reduce the system peak, except under emergency circumstances, it would not be appropriate to adjust the load profiles used for cost allocation purposes to reflect the impact of customers participating in demand response programs. Elenchus recommends that SaskPower continues to monitor the time of the application of the demand response programs to ensure that under normal operating conditions, the program does not have the effect of reducing the normal winter and summer peaks. If for emergency situations the demand response programs occurred at time of summer or winter maximum demands, for cost allocation purposes the curtailed load should be added back to the corresponding customer classes. Adding back the load would reflect normal operating conditions for the SaskPower system.

The demand response program expenses are classified into demand and energy based on the classification of Power Purchase Agreements, that is, 53% demand related.

Elenchus agrees with the classification of demand response program as Power Purchase Agreements. This assumes that in the absence of the demand response program, SaskPower would have had to purchase the curtailed amount of power in the interconnected electricity system.

7 ELENCHUS RECOMMENDATIONS' IMPACT

The impact on SaskPower customer classes of the three Elenchus recommendations: 1) Average and Excess method for classifying generation assets and expenses, 2) Minimum System with PLCC adjustment to classify distribution lines and transformers and 3) MDD definition for calculating annual non-coincident peak by rate class is shown in the following two tables.

Table 35: Impact on R:RR ratios of Elenchus Recommendations

Customer Class	R/RR Ratio (Existing)	R/RR Ratio (Revised)	Change
Residential	0.96	0.97	0.01
Farm	0.96	0.97	0.01
Commercial	1.03	1.03	0.00
Power Class	1.03	1.01	-0.02
Oilfields	1.02	1.03	0.01
Streetlights	0.86	0.78	-0.08
Reseller	0.93	0.94	0.01
Total	1.00	1.00	0.00

Table 36: Impact on Revenue Requirement ($M) of Elenchus Recommendations

Customer Class	$ M (Existing)	$ M (Revised)	Change
Residential	509.2	505.4	-3.81
Farms	164.9	164.7	-0.18
Total Commercial	420.9	418.6	-2.33
Total Power	593.9	600.7	6.86
Oilfields	324.6	323.3	-1.23
Streetlights	17.5	19.2	1.72
Reseller	96.8	95.8	-1.04
Total	2,127.7	2,127.7	0.00

8 Stakeholders' Comments

Stakeholders provided the following comments to Elenchus.

8.1 Saskatchewan Industrial Energy Consumers Association (SIECA)

In a letter dated February 27, 2017 to Troy King, Director Corporate Planning and Controller, SaskPower, SIECA raised the following issues:

1. If, as in the past, Elenchus will rely on utility survey data in evaluating SaskPower's cost of service methodology propriety, SIECA requests that Elenchus provide to stakeholders a list of all utilities surveyed (including any they choose to exclude from the report). In addition to the name and location of each utility surveyed, SIECA requests that Elenchus provide comparative metrics for each utility and the corresponding information for SaskPower. The metrics should include:

   (a) The number of customers by customer class

   (b) Amount of rate base

   (c) Generation capacity by generation type

   (d) System annual kWh

   (e) System peak hour kW and date and time

<u>Elenchus' Response</u>

Elenchus has included as much of the requested information as was available from publicly available sources in Appendix B of this report.

2. SIECA mentioned in its final submission to the Saskatchewan Rate Review Panel (SRRP) relating to the 2016-17 SaskPower Rate application; that our organization has been unable to find any previous quantitative analysis of customer class impacts for any alternatives to the Equivalent Peaker classification method. The recommendations on classification methodologies in the 2012 review conducted by Elenchus appeared to rely exclusively on subjective alignment with survey responses from other utilities. In its evaluation of SaskPower's generation cost

classification methodology, SIECA requests that Elenchus identify the specific alternative classification methodologies that are available to SaskPower and that will be analyzed as part of this review.

SIECA requests that the straight fixed/variable classification methodology be included in this review as a considered alternative. SIECA further requests that Elenchus calculate, compare and report to stakeholders the SaskPower revenue requirement for each customer class that results from the identified alternatives.

<u>Elenchus' Response</u>

Elenchus has identified the alternative generation classification methodologies that were explored. Note that the methodologies considered were limited to those that Elenchus considered to be the most reasonable options, taking into account SaskPower's characteristics and operating environment. Elenchus did not include the fixed variable method as an appropriate option for SaskPower. Elenchus considered methodologies that reflect cost causality and SaskPower's electricity system utilization. The NARUC manual includes the fixed variable classification method as a cost accounting approach[9], not a cost causality approach.

3. In its evaluation of generation cost classification, SIECA requests that Elenchus consider and discuss the propriety of allocating certain generation investment costs (i.e. solar or wind generation investment costs that are incurred to satisfy wider societal, environmental or governmental requirements) outside of the normal classification/allocation methodology. SIECA suggests the appropriate cost causation for new generation investment should not be determined by how customers utilize assets from an investment but rather should be determined from the driving factor that led to the investment in the assets. Generation investments to fulfill a wider societal, environmental or governmental obligations are not driven by the same factors that instigate or drive normal utility generation investment. Normal utility generation investment (and the classification/allocation thereof) is

[9] Electric Utility Cost Allocation Manual, page 35

driven by the express purpose of meeting customer demand at the least capital cost. Therefore, generation investments to fulfill wider societal, environmental or governmental obligations, that are not least capital cost, do not fit well into traditional generation cost classification/allocation methodologies. SIECA requests that Elenchus include in its study the evaluation of customer class revenue requirement calculations resulting from a methodology which removes wind and solar generation cost from the traditional classification/allocation methodology and instead allocates those costs to customer classes based each class's percent of total revenue requirement.

Elenchus' Response

SIECA's comments on this point reflect a policy view that is not generally accepted as a consideration that is relevant to cost allocation studies. All generation investment, past, present and future, must be made within the context of applicable public policy constraints, available technologies, etc. Cost allocation studies therefore allocate the actual cost of the actual investments to all customer classes based on cost causality principles and should not be subject to judgment on how they were initiated. Issues related to the policy constraints that determine the least cost generation options that are available to a utility are not addressed through cost allocation. Policy matters may be addressed through policy directives of government or, if appropriate, decisions with respect to rate design.

From the utility's perspective, generation, regardless of how it was initially built, is used to produce electricity for its customers, it is a shared asset and should be allocated to all customers using fair and reasonable parameters. If judgment is used to apportion generation assets, it could be argued that, for example, hydroelectric generation which has to be sited where there are available water resources, should be allocated only to customers that happen to reside near the plant. One of the main principles applied in cost allocation and rate design is the "postage stamp" principle. Utilities use common assets to satisfy customers demand for energy and the shared assets should be allocated to customer classes using parameters that reflect how they consume energy without judgment as to the type of generation used to satisfy demand.

Based on the utility survey, the percentage of demand related wind and solar generation used in a cost allocation study varies from 0% to 100%. These types of generation assets are included in the utilities' cost allocation studies and are treated as generation resources.

4. If the Equivalent Peaker Method is one of the generation cost classification methodologies evaluated, SIECA requests that Elenchus calculate and compare the SaskPower revenue requirement for each customer class that results from; a) using new generation investment cost as the basis for determining the relative cost of generation or b) using the actual original investment in each of SaskPower's generation facilities adjusted for inflation.

Elenchus' Response

The requested calculation would necessitate an assessment of the least cost peaking capacity from a system planning perspective recognizing the realities of the SaskPower generation fleet and operating environment.

It is also possible that SaskPower may not have access to the original cost figures and the plants most likely have undergone extensive additions and modifications since been declared in-service. Even if SaskPower would be able to obtain the necessary data, it will require a significant effort in order to do the calculations as requested by SIECA.

5. In its evaluation of SaskPower's demand cost allocation methodology, SIECA requests that Elenchus calculate and compare the SaskPower revenue requirement for each customer class that results from a true 1CP, a true 2CP and from SaskPower's current "2CP" methodology which is based on an average of three winter hourly peaks and three summer hourly peaks for five historical annual periods. This current method is described as a "2CP" method but could be more accurately described as a 30CP methodology. Further, Elenchus should provide to stakeholders a detailed analysis of the SaskPower utility system power consumption characteristics which would theoretically justify deviation from a true 1CP allocation methodology in favor of a true 2CP allocation methodology.

Additionally, Elenchus should demonstrate how and why the SaskPower system fits the characteristics of a 2CP system.

<u>Elenchus' Response</u>

Elenchus understands that SaskPower uses the average of three winter hourly peaks and three summer hourly peaks in order to provide more stability to the results and eliminate volatility. The three winter and three summer hours used for each historical year are not for three different months. They could be for contiguous hours on the same day. Based on 2015 data shared by SaskPower's staff with Elenchus, the 2015 winter peak using the 3 highest winter hours in order to develop the 2 CP allocators had values of 3,536.4 MW, 3,531.5 MW and 3,525.1 MW. In the summer, the 3 highest hourly demands were 3,272.8 MW, 3,262.3 MW and 3,226.3 MW. Based on these values, it appears that there will not be a significant difference between using the highest maximum demand or the average of the three highest maximum demands in order to develop the 2 CP allocators under normal circumstances (i.e., in the absence of a 1CP outlier). Using more values in order to reduce volatility in the results is an accepted methodology in cost allocation.

Elenchus is not proposing returning to use 1 CP as a demand allocator since it does not reflect SaskPower's operating characteristics and Elenchus sees no value in running the scenario suggested by SIECA.

Elenchus in its report in section 6.5.4 explains why it continues to support 2 CP allocation but Elenchus did not conduct a detailed analysis of SaskPower's utility system power. This kind of analysis, if required, would have to be done by SaskPower.

8.2 SASKATCHEWAN INDUSTRIAL ENERGY CONSUMERS ASSOCIATION (SIECA)

SIECA submitted another letter to Troy King dated May 26, 2017 with multiple questions for Elenchus and SaskPower. SIECA's questions and responses from Elenchus and SaskPower are included as Appendix D.

8.3 MEADOW LAKE MECHANICAL PULP INC.

Meadow Lake Mechanical Pulp Inc. (MLMP) submitted the following questions to Elenchus at the March 30 public meeting

1. It is the request of MLMP that Elenchus benchmark TOU spreads and also incorporate this element in the cost of service analysis. The desired outcome is that the E85 spread be significantly increased. Over time, this DSM tool can improve system cost efficiency.

<u>Elenchus response</u>

Elenchus conducted a survey of utilities that have time of use rates in order to determine the differentials used between peak and off-peak rates and the results of this survey are shown below.

SaskPower Time of Use Rate Survey

Utility	ENMAX	EPCOR	Toronto Hydro	Pacific Power and Light	Seattle City Light
Criteria for time-of-use rates (mandatory/voluntary)	mandatory -- for qualifiers	Wires/Dis: Mandatory for above 150 kVA in demand Energy: Voluntary	Mandatory by the OEB.	Mandatory for large customers.	Mandatory to Large GS (1,000 kW-9,999kW /month) and High Demand GS (10,000+ kW/month)
Reason for ToU differential (cost-based/incentive to shift consumption)		Cost-based	Incentive to shift		
ToU: For rate generation or the entire bill		Generation	Generation	Generation	Applicable to the total electricity bill.
Energy rate differential between peak and off-peak (¢/kW)	Primary: $0.009725 difference Secondary: $0.007936 difference	Primary: $0.01045 difference Commercial/Industrial 150kVA to <5000kVA: $0.01040 difference	Businesses: $0.093 difference	0	Large GS: 2.53 cents/kWh difference High Demand GS: 2.41 cents/kWh difference
Demand rate differential between peak and off-peak ($/kW)	0	0	0	Large GS >1000kW Differential: Secondary ($3.74), Primary ($3.17), Transmission ($3.61)/kW	Large GS: 1.86 cents/kW difference High Demand GS: 1.86 cents/kW difference

Caution should be used in extrapolating the results of the survey to SaskPower's time-of-use rates. Utilities implement time-of-use rates usually for two reasons:

- To reflect their own system characteristics and cost structures to encourage customers to shift load away from the peak period and into the off-peak period, or
- As a conservation measure, perhaps tied to demand management initiatives.

The costs structures of utilities reflect their own circumstances and the differentials between peak and off-peak rates in one utility are not necessarily transferable to the circumstances of another utility. It is Elenchus view that SaskPower should reflect its own system characteristics and cost structures when designing its time-of-use rates and should not rely on another utility's rate design structure. Elenchus understands that in SaskPower's case, the fuel at the margin is natural gas and if customers shift consumption away from the peak period and into the off-peak period, the shift would not result in significant savings to SaskPower. This may be the reason that the differential between SaskPower's peak and off-peak rate is only 1 ¢/kWh.

Elenchus understands that when SaskPower initiated its TOU program in 2007, it offered a $10/MWH (1¢/kwh) differential to customers that has not changed. The value of the differential has dropped from $8.44/MWH to less than $1.00/MWH (0.1 ¢/kwh) since the inception of the program.

In order to provide additional incentive for customers to shift consumption from the peak period and into the off-peak period, SaskPower may want to explore the possibility of also establishing demand rates that are different in the peak period compared to the off-peak period, as long as the demand rates reflect cost causality. As an example, in Ontario time-of-use demand rates are based on the coincident demand established by large customers during the peak period, or 85% of the maximum demand in the peak period, whichever is greater. There is no demand rate applicable to off-peak demand.

2. The E82, E83, E84 and E85 rate codes reflect different supply voltages. Specifically they go from 25 kV to 72 kV to 138 kV up to 230 kV of voltage. In electricity transmission, the higher the voltage, the lower the energy losses.

   With higher voltage, the energy charge drops from E82 to E83 to E84. However, there is no drop in the energy charge from E84 to E85. E85 (230 kV) should have lower energy charges than E84 (138 kV).

   It is the request of MLMP that Elenchus evaluate this point as it relates to cost of service. The desired outcome is to have a reduced energy charge when moving from the E84 to E85 rate code.

<u>Elenchus Response</u>

Elenchus discussed with SaskPower the possibility of establishing a 230 kV rate in order to determine the practicality of establishing a rate for 230 kV supplied customers that is different than the rates for E 84 (138 kV) customers. This would run counter to the rate consolidation proposal discussed in section 6.5.3.

Elenchus' view is that rates should reflect the assets utilized by customers based on cost causality principles, so there seems to be merit in having rates for 230 kV supplied customers that are different than the rates for customers supplied at 138 kV. For practical reasons, SaskPower may not be able to develop such rate, for example, there may not be a significant cost based rate differential between 230 kV rate and 138 kV rate, SaskPower may not have a loss factor estimate for customers supplied at 230 kV, there may be a wide range of customer consumption characteristics that would be included in such a rate group, or very few customers that would qualify for the rates.

8.4 MEADOW LAKE MECHANICAL PULP INC.

On May 15, 2017 Meadow Lake submitted speaking points on Elenchus presentation at the Public meeting. The following issues were raised:

8.4.1 BIAS AGAINST CUSTOMERS THAT GENERATE ECONOMIC ACTIVITY

Elenchus sees no evidence of bias in SaskPower's Cost Allocation methodology. SaskPower's objective in its Cost Allocation study is to allocate costs based on the principles of cost causality in a fair and consistent manner in alignment with industry standards. SaskPower conducts an independent review every 5 years to confirm that the Cost Allocation methodology reflects its own circumstances and is based on sound cost allocation principles.

8.4.2 TIME OF USE RATES

Elenchus responded to MLMP issue with respect to time-of-use rates in section 8.3 of this report.

8.4.3 230 KV RATE

SaskPower will, along with Elenchus, revisit the recommendation to consolidate the 138kV and 230kV rates

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Appendix A: SaskPower Cost Allocation Methodology Documentation

The information below was extracted from a document titled: "2015 Base Embedded Cost of Service Study" prepared by SaskPower.

III. COST OF SERVICE METHODOLOGY

The study follows a five step process:

- The first step is to ***identify*** in detail the accounting costs that are to be allocated to customer classes.
- The second step is to ***functionalize*** the costs between generation, transmission, distribution and customer services functions.
- The third step is to ***classify*** each set of functionalized costs into demand, energy and customer components.
- The fourth step is to ***allocate*** the functionally classified costs among the several customer classes.
- The fifth step is to ***compare*** between the allocated costs and the revenues collected from the customer classes to arrive at the revenue to cost ratios.

STEP 1: IDENTIFICATION

The initial step is to identify the accounting costs to be included in the Cost of Service Study. SaskPower Finance has supplied the 2015 Year End Consolidated Financial Summary.

Three types of accounts are separately identified in detail:

1. Rate Base Items – investments and liabilities as reported in SaskPower's Balance Sheet. Please refer to ***Schedule 1.0*** for summary of these items as well as the actual data for the 2015 Base Year. Data is reported for the year end in the following categories:

- Plant in service
- Accumulated Depreciation
- Allowance for Working Capital
- Inventories
- Other Assets

Plant in service is reported in more detail by function: Generation - by type of generation, Transmission - by voltage level, Distribution Plant - by type of plant, and General & Intangible Plant - by primary usage (unused land, buildings, office furniture and equipment, vehicles & equipment, computer development & equipment, communication, protection & control, and tools and equipment).

Contributions in Aid of Construction were previously netted against Fixed Assets as part of the Rate Base and amortized over the estimated service life of the related asset. The amortization of these contributions was netted against Depreciation Expense under GAAP. However, with the adoption of IFRS accounting standards in 2011, Contributions in Aid of Construction is recognized immediately as Other Income when the related fixed asset is available for use.

2. Revenue Requirement – this is a calculation of annual costs (from SaskPower's Income Statement) plus the Return on Rate Base (calculated as Rate Base multiplied by the system average Return on Rate Base percentage). The system average Return on Rate Base is equal to total revenue minus total expenses divided by the total rate base. Please refer to ***Schedule 1.0*** for a summary of these items as well as the actual data for the 2015 Base Year. Data is reported for the year end in the following categories:

- Fuel
- Purchased Power
- Export Revenue (Credit)
- Operating, Maintenance, & Administrative
- Depreciation and Depletion
- Corporate Capital Tax
- Grants In Lieu of Taxes
- Miscellaneous Tax
- Other Operating Revenues (Credit)
- Return on Rate Base (Rate Base multiplied by the system average Return on Rate Base)

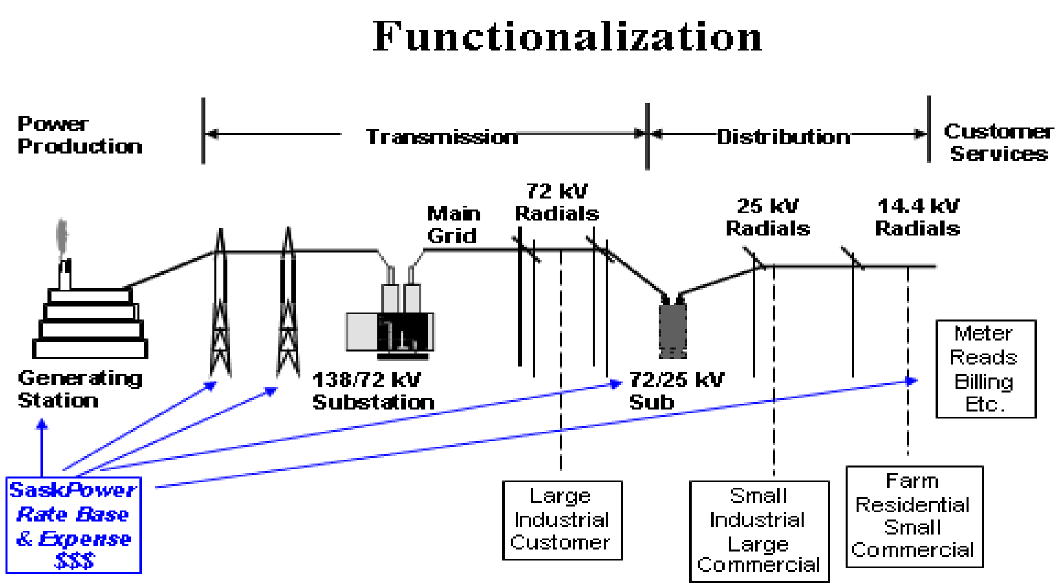
3. Revenue Items - annual domestic sales revenues as reported on SaskPower's Income Statement. For forecast (Test) years, SaskPower's Load & Revenue Forecasting department provides a projection of net sales within Saskatchewan. ***Schedule 7.0*** provides a summary by customer class of the actual revenues for the 2015 Base Year.

STEP 2: FUNCTIONALIZATION

The second step is to functionalize all accounting costs, in terms of plant and expenses into the major functions of SaskPower's integrated electric system. Please refer to Figure 1 for a schematic of the process. Rate base and expenses are assigned to the following functions and sub functions:

1. Generation Load Losses Scheduling & Dispatch Regulation & Frequency Response Spinning Reserve Supplementary Reserve Planning Reserve Reactive Supply Grants in Lieu of Taxes	**3. Distribution** Area Substations Distribution Mains Urban Laterals Rural Laterals Transformers Services Instrument Transformers Meters Streetlights Customer Contributions
2. Transmission Main Grid 138kv Lines Radials 138/72kv Substations 72kv Lines Radials	**4. Customer Service** Metering Services Meter Reading Billing & Customer Accounts Customer Collecting Customer Service Marketing & Sales

Figure 1: Functionalization Schematic



Please refer to ***Schedules 2.00 through to 2.36*** for the functionalization of the financial accounting details. A summary of the functionalization methodology is summarized below for rate base and revenue requirement which includes annual expense items from the income statement and return on rate base.

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.

- **General Plant - Office Furniture & Equipment:**
  The functionalization and sub-functionalization is 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.

  - **CO_2 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:

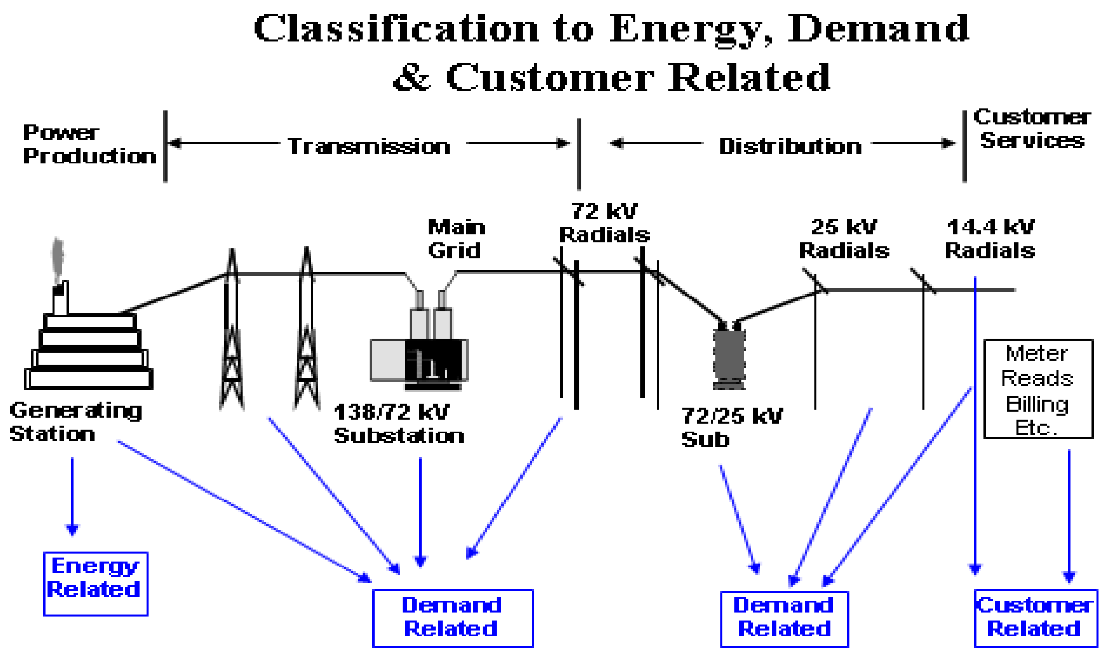
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission and distribution systems.

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.

Figure 2 below presents a schematic of the classification process.

Figure 2: Classification Schematic



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

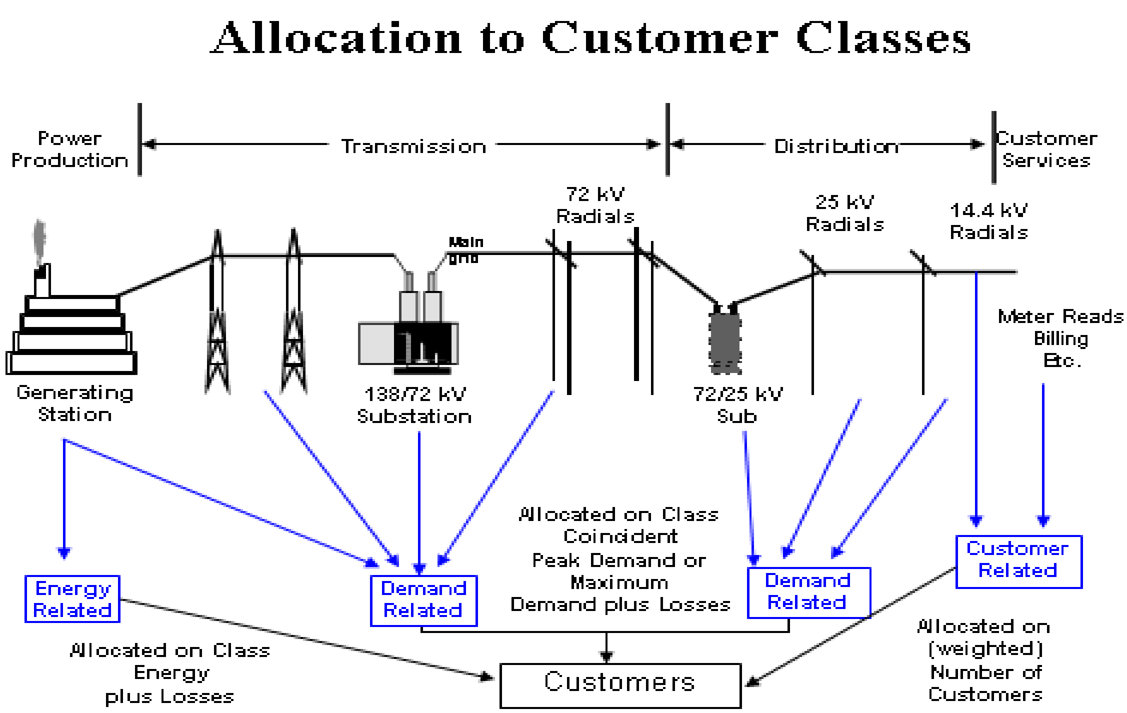
Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

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

Figure 3 presents a schematic of the allocation process. The methodologies chosen by SaskPower for allocation are summarized in ***Schedule 3.0***. The core data used in the development of allocation factors can be found in ***Schedule 4.0***.

Figure 3: Allocation Schematic



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.

- **Allocators**
  The allocation factors are summarized in ***Schedules 5.0 to 5.3***. The functionalization and classification of the revenue requirement is summarized in ***Tables 1 and 2*** (Summary of Results section), and the details are in ***Schedules 6.0 to 6.3***.

STEP 5: COMPARE

The allocated rate base, allocated expenses and class revenue are the foundation for calculating the revenue to revenue requirement (R/RR) ratio by class. A R/RR measure of 1.00 indicates that the revenues received from a customer class exactly matches the costs of providing it electrical service; or, to put it simply, a customer is paying the amount it costs SaskPower to provide them with service. An R/RR below 1.00 indicates that a customer class is paying less than the cost to serve while an R/RR above 1.00 indicates that a customer class is paying more than the cost to serve. On a system-wide basis, the ratio must equal 1.00.

In response to comments of cross-subsidization between SaskPower's customer classes, external consultants have advised SaskPower that R/RR ratios close to 1.00 are deemed to be reasonable. Cost allocation studies of shared assets utilized by various customer groups represents the best and most current information available but is subject to fluctuations and uncertainty from year to year. A range of acceptable R/RR ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that a customer is paying their fair share of costs. As a result, an R/RR ratio that is slightly above or below 1.00 does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes as long as it falls within the acceptable range. In conclusion, if the R/RR ratios are within the acceptable range, the results are deemed to be reasonable and there is no refutable evidence of cross-subsidization.

Revenue to revenue requirement (R/RR) ratios are determined by comparing the revenue collected from each class to the revenue required to serve the customer class. The revenue requirement for each customer class is calculated as the allocated rate base multiplied by the system return on rate base plus allocated expenses. Please refer to ***Table 3*** in the Summary of Results section for an R/RR ratio breakdown by customer class.

It is important to note that R/RR ratios are not static. Each year SaskPower rebuilds the cost of service model using the latest annual financial information and customer revenue and load data. As such, cost of service results vary from year to year for a number of reasons, including:

- Class Revenue Changes
- Class Revenue Requirement Changes, due to:
    - Non-uniform escalation of generation, transmission, distribution & customer services costs (e.g., capital expenditures, fuel & purchased power, OM&A and depreciation expense)
    - Changes to cost of service methodology
    - Changes to class demand (e.g., customer load factors) at system peak, due to:
        - Economic conditions
        - Mechanical failures

- Unforeseen shutdowns
- Operational changes
- Variations in weather patterns

R/RR ratios in Base years are dependent on the actual annual revenue and the calculated revenue requirement derived from the cost of service study which may reflect any, or all, of the above conditions.

In Test (forecast) years, SaskPower attempts to set the R/RR ratios between 0.98-1.02 using assumptions based on a “most likely” scenario, to stabilize rate designs and protect all customers from outlying or anomalous conditions that may occur.

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Appendix B Utilities Surveyed

Canadian

BC Hydro

ATCO Electric

Manitoba Hydro

Hydro One Networks Inc.[10]

Hydro Quebec

Newfoundland Power

New Brunswick Power

Nova Scotia Power

US Utilities

Consumers Energy

Georgia Power

Many more utilities were contacted, but did not respond.

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

The utilities surveyed have the following statistics.

SaskPower Comparative Metrics

Category	The Number of Customers by Customer Class						
	Residential	Commercial			Industrial		Other
BC Hydro	*Residential* 1,727,945	*Com. & Light Ind.* 203,466			*Large Industrial* 183		3,474
ATCO Electric	*Residential* 205,704	*Commercial* 32,078	*Irrigation* 137	*Farm* 34,122	*Industrial* 6,886	*Oilfield* 9,682	
Manitoba Hydro	*Residential* 497,699	*Commercial/Industrial* 69,935					
Hydro One	*Residential* 54% of 1,347,231	*General Service* 29%			*Large Users* 10%		*Embedded Dist.* 7%
Hydro Quebec	*Residential* 3,890,956	*Com., Small Ind. Institutional* 319,294			*Industrial* 181		*Other* 4,290
NB Power	*Residential* 323,530	*General Services* 25,676	*Direct* 353,813	*Indirect* 45,242	*Industrial* 1,729		*Non-metered* 2,878
NS Power	*Domestic* 462,809	*Small General* 24,939	Demand General 10,953	Large Gen 20	*Small Ind.* 2,156	Other Ind 219	*Other* 9,428
Nfld. Power	*Residential* 229,815	*General Service* 34,591					
Georgia Power	*Residential* 2,127,658	*Commercial* 304,179			*Industrial* 9,141		*Other* 9,261
Consumers' Energy							

SaskPower Comparative Metrics

Category	Rate Base (millions)	Electric Sales MWh	System Peak Hour MW, Date, Time	Generation Capacity by Type (MW)							
				Hydro	Wind/Solar	Oil	Gas	Coal	Nuclear	Diesel	Other
BC Hydro	14,965.60	51,213,000	9,441	11,440.20			1,069			59.2	
ATCO Electric	4,504	11,582,998	08/12/2016 16:00 17,036	N/A Distribution							
Manitoba Hydro				5,228			375	83		10	
Hydro One	Trans: 10,175 Distr.: 6,739	T: 137,000,000 D: 28,900,000		N/A Distribution							
Hydro Quebec	10,590	171,263,000	02/15/2015 7:00 37,349	36,370			411			130	
NB Power				889		972	525	467	660		
NS Power	3,614	10,839,237	12/16/2016 18:00 2,111	393	W: 81	Steam: 369 Comb: 278		1,242			45
Nfld. Power	1,061.04	6,345,646	12/29/2015 17:00 1,367	98						42	
Georgia Power	16,000	83,805,000	21/07/2015 15:00 16,104	1.60%			28.30%	24.50%	17.60%		
Consumers' Energy	10,184 (electric) 4,024 (gas)	37,000,000	7,812 (Summer)	1,069	34W	Steam: 1,682 Comb: 329		2,771			

	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 37.4% demand
Hydro One	NA
Hydro Quebec	Maximum of 165 TWh at 2.79 ¢/kWh allocated based on consumption (utilization factor during 300 hours
NL Power	System load factor 44.9% demand
NB Power	# CP and Average 47.3% demand
NS Power	All hydro investments are demand except environmental which are energy. Demand related based on system load factor
Georgia Power	100% demand
Consumers Energy	Fixed and variable, net plant 100% demand, O&M 56%demand

	Hydroelectric	Baseload Steam	Combined Cycle	CTU	Transmission	Sub-transmission
BC Hydro	55% demand/45% energy	100% demand	100% demand	100% demand	100% demand	100% demand
ATCO	NA	NA	NA	NA	AESO bill into demand/customer	30% to 35%
Manitoba Hydro	37.4% demand	37.4% demand	NA	37.4% demand	100% demand	100% demand
Hydro One	NA	NA	NA	NA	N/A	N/A
Hydro Quebec	34.4 2013 Load Factor	NA	NA	NA	42.7% demand	100% demand
NL Power	System load factor 44.9% demand	NA	NA	NA	100% demand	100% demand
NB Power	47.3% demand	47.3% demand	NA	47.3% demand	100% demand	Same as TX
NS Power	Not easily available	Not tracked for all costs by type	As Baseload Steam	100% demand	Currently 43.5% demand	Currently 43.5% demand
Georgia Power	100% demand	100% demand	100% demand	100% demand	100% demand	100% demand
Consumers Energy	100% of net plant is demand related and 64% of O&M is demand related	100% of net plant is demand related and 56% of O&M is demand related	100% of net plant is demand related and 27% of O&M is demand related	100% of net plant is demand related and 27% 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	100% demand	100% customer
ATCO	100% demand	100% demand	40% to 60% demand	40% to 60% demand	30% to 35% demand	100% customer
Manitoba Hydro	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer
Hydro One	100% demand	50% demand related	38% demand	38% demand related	50% demand related	100% customer
Hydro Quebec	100% demand	100% demand	100% demand	77% demand	77% demand	100% customer
NL Power	100% demand	67%	79%	79%	67%	100% customer
NB Power	100% demand	50% demand	75% demand	75% demand	50% demand	100% customer
NS power	100% demand	73% demand	100% demand	100% demand	50% demand	100% customer
Georgia Power	100% demand	84% demand	100% demand	75% demand	75% demand	100% customer
Consumers Energy	100% demand	100% demand	100% demand	100% 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 system	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	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (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	Highest 12 CP or 85% 12 NCP during peak hours for Networks	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	most frequently used and smaller, Zero intercept	12 CP	Bulk power transmission: Step-up substations - 12 MCP 115 kV to 500 kV lines and subs - 80% 4-	4 CP	69 kV to 46 kV - 4-CP (4-CP is June - Sept) Primary and Secondary - NCP

				CP & 20% 12-CP (4-CP is June - Sept) Sub-transmission Levels (69 kV to 46 kV) - 4-CP Primary and Secondary - NCP (Non-coincident peak)		
Consumers Energy	100% customer	FERC accounts 360 through 368 are considered demand related, while accounts 369 through 373 are considered customer related	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)
Consumers Energy	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
Consumers Energy	NA	Number of customers	Weighted # of customers

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APPENDIX C ELENCHUS TEAM QUALIFICATIONS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for 40 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 250 regulatory proceedings and provided expert evidence in over 125 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc. (ECS) **1980**

- ECS was divested as a separate company in 2003
- There are presently four ECS consultants: Bill Harper, Mark Garner, Shelley Grice, and James Wightman. Web address: www.econalysis.ca

EDUCATION

1975 Masters in Business Administration in Economics and Management Service, University of Toronto

1972 Bachelors of Science in Electrical Engineering, University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**

Research Assistant, Univ. of Toronto, Faculty of Management Studies **1973 - 1978**

Bell Canada, Western Area Engineering **1972 – 1973**

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant:

Before the Ontario Energy Board

John Todd has provided expert assistance in a total of 62 proceedings before the Ontario Energy Board from 1991 to 2016. He has presented evidence in 25 of these cases. The most recent case he participated in was the *Independent Electricity System Operator, 2016 Usage Fee*. Evidence: Cost Allocation and Rate Design for the 2016 IESO Usage Fee.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 46 proceedings before the Public Utilities Board of Manitoba from 1990 to 2015. He has presented evidence in 23 of these cases. The most recent case he participated in was the *City of Winnipeg: Manitoba Hydro 2015/16 GRA and Manitoba Hydro COSS Review.*

Before the British Columbia Utilities Commission

John has provided expert assistance in a total of 33 proceedings before the British Columbia Utilities Commission from 1993 to 2006. He has presented evidence in eight of these cases. The most recent case he participated in was the *British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement.*

Before the Régie de l'énergie

John has provided expert assistance in a total of ten proceedings before the Régie de l'énergie from 1998 to 2014. He has presented evidence in nine of these cases. The most recent case he participated in was the *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.*

Before the Alberta Energy and Utilities Board

John has provided expert assistance in of two proceedings before the Alberta Energy and Utilities Board in 2001. He has presented evidence in one case. The second case of 2001 was in regards to the case of *Generic, Gas Rate Unbundling (2001-093)*. Evidence: Canadian Experience and Approaches.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2015. He has presented evidence in three cases. The most recent proceeding he participated in was the *Newfoundland Power, 2016 Deferred Cost Recovery Application* case.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of nine proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2016. He has presented evidence in three cases. The most recent proceeding he participated in was the *2015 New Brunswick Power Customer Cost Allocation Student Review.* Evidence: Cost Allocation Study Review.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of nine proceedings before the Nova Scotia Utility and Review Board from 2008 to 2016. He has presented evidence in four cases. The most recent proceeding he participated in was *Efficiency One, Updated Cost Allocation Methodology.*

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2016. He has presented evidence in 13 of these cases. The most recent proceeding he participated in was a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134.*

Before the Ontario Telephone Services Commission (OTSC)

John has provided expert assistance in one proceeding before the Ontario Telephone Services Commission in 1992. The case was in regards to a *Review of Rate-of-Return Regulation for Public Utility Telephone Companies.* Evidence used: The need for OTSC regulation of municipal utility telcos.

Before the Ontario Securities Commission

John has provided expert assistance in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case. The most recent proceeding he participated in was a *Securities Industry Review.* Evidence: Industry structure and the form of regulation.

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy.

Non-Hearing Processes

John has provided expert assistance in 17 non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in 6 commercial arbitrations and lawsuits between 2004 and 2015.

Facilitation Activities

- 5 Strategic Planning sessions with Executive and/or Board of Directors of regulated companies between 2000 and 2015
- 6 stakeholder processes for regulators and utilities from 2000 through 2016

Other Regulatory Issues Researched

- Over 20 studies completed for regulators, utilities and others outside of hearing processes

SELECTED PRESENTATIONS

- Productivity Benchmarking Panel at Canadian Electrical Association RITG CAMPUT Workshop (May 2016)
- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Committee and Regulatory Innovations Task Group (June 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (2016)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2016
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How to Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Assoc.
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over 70 private sector companies, including utilities

15 industry and other associations

Over 30 consumers' associations and legal clinics

Government

- 5 Regulatory Tribunals
- 6 Federal departments
- 14 Provincial departments, commissions and agencies
- 13 municipal and other departments/entities

For John Todd's complete curriculum vitae, please visit: www.elenchus.ca

MICHAEL J. ROGER

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ASSOCIATE, RATES AND REGULATION

Michael has over 38 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario

Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

Appendix D SIECA Letter May 26, 2017

RESPONSE TO SIECA QUESTIONS

Saskatchewan Industrial Energy Consumers Association **(**SIECA**)** sent a letter to Troy King, dated May 26, 2017 with interrogatories addresses to Elenchus. Below are Elenchus' and SaskPower's staff responses to the questions raised by SIECA in its letter.

1. Confirmation of Underlying Basis for the 2017 Cost of Service Review

The Elenchus draft report that was tabled and posted on SaskPower's website on May 10, 2017 states on Page 2 that "***Elenchus has reviewed the documentation (2015 Base Embedded Cost of Service, dated October 14, 2016) to confirm that the SaskPower model is consistent with the documentation of the methodology***."

SIECA Query 1.1

Were the revenue and revenue requirement amounts in the referenced report used to form the basis for assessments and comparisons conducted on recommend changes to the COS by Elenchus?

Elenchus Response:

Yes

SIECA Query 1.2

Were the billing determinants in the referenced report used to form the basis for assessments and comparisons conducted on recommend changes to the COS by Elenchus?

Elenchus Response:

Yes

SIECA Query 1.3

Upon review of the Elenchus draft report, SIECA had to make a special request on May 12, 2017 to SaskPower to obtain a copy of the 2015 Base Embedded Cost of Service Study report in order to prepare comments and questions for the May 15, 2017 Public

Update Meeting. Please explain why the report was not tabled on the SaskPower website at the beginning of this COS Review proceeding in February 2017 to provide stakeholders with a basis for understanding the COS and to establish a baseline for assessing the impacts of potential changes to the COS methodologies.

SaskPower Response:

The 2015 Base Embedded Cost of Service Study not being tabled at the beginning of the Cost of Service Review was an oversight on SaskPower's behalf. Normally, only the "Test" version of this report is tabled as part of the Rate Application process; the "Base" version is an internal document and not widely distributed.

SIECA Query 1.4

On slide 20 of the presentation made by Elenchus on May 15, 2017 the consultant illustrated a high level comparison of generation classification outcomes between the Average and Excess method and the 2CP and Average method. To make this comparison Elenchus and SaskPower would have to have incorporated the 2CP and Average methodology into the SaskPower COS model.

Therefore, please provide a version of the 2015 Base Embedded Cost of Service Study report that has been modified to utilize the 2CP and Average generation classification method (as opposed to the Equivalent Peaker or Average and Excess methods) and that incorporates all other preliminary recommended changes to the COS proposed by Elenchus. **This information is required by cob Monday May 29, 2017 in order to allow SIECA to comply with the May 30, 2017 deadline for final written submissions established by SaskPower.**

SaskPower Response:

SaskPower provided the requested information on May 29, 2017 to SIECA.

2. Cost Causality

Elenchus states on Page 3 of its draft report that "***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"***

SIECA Query 2.1

Please define cost causality.

Elenchus Response:

The cost causality principle in a cost allocation study refers to the concept that to the extent feasible and practical, costs imposed by customers on the utility should be borne by the same customers. Hence, a cost allocation study apportions shared assets and expenses between customer classes by relating utility's costs to the relevant cost drivers. For example, the required capacity of the electricity system is "caused by" the total demand that must be accommodated by the system to reliably meet the requirements of all customers simultaneously.

The classification methods used in a cost allocation study are based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers. The allocation methods used in a cost allocation study identifies 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.

SIECA Query 2.2

Please define cost causality as it relates to the decision to invest in new generation.

Elenchus Response:

The utility decision to invest in new generation can be related to replacing existing generation that has reached end of service life, replacing or adding new generation as per Government policy directives, or increasing total resources in order to meet the forecast of the future total capacity and/or energy requirements imposed by customers on the utility.

Like other utilities, SaskPower operates a fully integrated system that does not associate specific loads with specific generation, transmission and distribution assets. For these reason, in allocating costs to customers classes, it is not appropriate to associate specific new assets with specific loads. Rather, the system is designed and built to meet the aggregate future requirements of all customers and the total system is in place to accommodate those requirements. In a given test year, linkage between costs and cost drivers is determined on an aggregate basis.

SIECA Query 2.3

Please provide a description of the process and criteria that is used to determine how and when a decision to invest in new generation is made by SaskPower?

SaskPower Response:

Saskatchewan prepares the Ten Year supply plan annually which outlines the corporation's generation plan and defines the demand and resources to meet the province's future electricity needs. SaskPower's plan provides the framework for future generation resources being sufficient to meet forecasted future load. It also considers retirement of existing units, planned and major overhauls to units, degradation of unit performance between overhauls, escalating fuel prices, escalating capital costs for new units, unit operating costs and regulatory requirements.

The process consists of starting with a number of internal consultation sessions to discuss the requirements, alternatives and possible future obstacles that would need to be included to capture in developing the Supply Plan. The next step determines the amount of generation required through reliability modeling. Once the generation requirement is assessed, various strategies, and supply alternatives that could be available by the required date are taken into consideration to meet the capacity shortfall and energy requirements.

SIECA Query 2.4

How did Elenchus consider the process and criteria SaskPower uses to decide when to invest in new generation in its determination of generation cost causality?

Elenchus Response:

Consistent with the concept of a fully integrated utility, Elenchus did not differentiate between existing and new generation when evaluating SaskPower's Functionalization, Categorization and Allocation of generation assets and expenses in the cost allocation study.

Elenchus did not consider the process and criteria SaskPower uses to decide when to invest in new generation. System planning is the methodology used to determine the required capacity and energy that would have to be accommodated reliably in the future as well as the least cost option for meeting those requirements.

Elenchus' experience is that in a cost allocation study, the process and criteria used by a utility to invest in new generation is not relevant in order to determine the methodology to apportion generation assets and expenses to customer classes.

3. <u>Efficacy of Revenue to Revenue Requirement ratio metrics.</u>

The Elenchus draft report on Page 4 states, "***The ratio of revenue to revenue requirement illustrates to what extent the class is paying for their share of costs imposed on the utility.”***

<u>SIECA Query 3.1</u>

Does Elenchus believe that the revenue to revenue requirement (R/RR) is a valid and appropriate measure of the propriety (fairness and equity) of SaskPower's current cost classification/allocation methodology? If so, explain why?

Elenchus Response:

Yes. Revenue to revenue requirement ratios are used in a cost allocation study as a measure of customer classes paying their fair share of costs imposed on the utility.

Based on Elenchus’ review of SaskPower’s cost allocation study, the study is based on commonly accepted methodologies that are based on cost causality principles and therefore, it is Elenchus’ view that the ratios are a fair and equitable reflection of the costs imposed by customer classes on the utility.

<u>SIECA Query 3.2</u>

How does the R/RR ratio distinguish between the impact of revenue requirement and allocation methodology?

Elenchus Response:

The ratio does not distinguish between the impact of revenue requirement and allocation methodology. A cost allocation study is conducted reflecting the approved revenue requirement for the utility. The level of assets and expenses that the utility needs to serve its customers is established before a cost allocation study is conducted in order to apportion the shared assets and expenses amongst the utility’s customer classes.

<u>SIECA Query 3.3</u>

The Elenchus draft report states, "***Many jurisdiction use a range of 0.95 to 1.05, or 0.90 to 1.10 as acceptable revenue to revenue requirement ratios when establishing revenue responsibilities by customer class***." Is this statement based on a survey? If not what is the basis for this assertion?

Elenchus Response:

This statement is based on Elenchus' experience in working in most jurisdictions across Canada.

SaskPower Response:

SaskPower conducts an annual R/RR ratio survey of Canadian Utilities. The most recent results are in the table below:

Canadian Utility	R/RR Target Range	Residential Customers R/RR	Commercial (Urban & Rural) R/RR	Power Customers R/RR	Streetlights
ATCO Electric	NA	NA	NA	NA	NA
BC Hydro	0.933 to 1.736	.933	1.119 to 1.1172	1.013 to 1.026	1.048 to 1.736
Manitoba Hydro	0.95 to 1.05	1.00	.99 to 1.08	0.91 to 1.00	1.00
NB Power	0.95 to 1.05	0.93	1.03 to 1.16	1.00 to 1.05	1.91
NFLD Power	0.90 to 1.10	0.96	1.09 to 1.12	1.04	1.03
Hydro-Quebec	0.84 to 1.31	0.840	1.194 to 1.31	1.085 to 1.134	n/a
Nova Scotia Power	0.95 to 1.05	0.99	0.99 to 1.05	0.97 to 1.02	1.00
SaskPower	0.95 to 1.05	0.98	1.02 to 1.03	1.00	0.96

Note: SaskPower's results are based on the 2016 rate application

The results clearly show that SaskPower is well within Canadian electrical industry standards with regards to its R/RR ratio range.

SIECA Query 3.4

Did Elenchus determine how many jurisdictions/utilities utilize methods or metrics other than the ratio of revenue to revenue requirement to determine the propriety of a cost allocation methodology?

Elenchus Response:

Elenchus does not use the ratio of revenue to revenue requirement to determine the propriety of a cost allocation methodology. The ratio of revenue to revenue requirement is produced as a result of a cost allocation methodology. This result provides guidance in determining rates that are just and equitable.

<u>SIECA Query 3.5</u>

Please explain how the revenue (numerator) of the R/RR ratio was determined when calculating the R/RR ratios that were used to compare the impacts of alternative or recommended classification or allocation methods recommended by Elenchus?

SaskPower Response:

The revenue (numerator) values of the R/RR ratios used to compare the impacts of alternative methods are based on actual billed revenue data for 2015 to be consistent with the total revenue requirement values which is based on 2015 costs. For all 2015 Base R/RR ratios, the revenue (numerator) for the class never changes; only the allocated revenue requirement (denominator) will vary depending on the impacts of the alternative methodology being explored.

<u>SIECA Query 3.6</u>

What statistical method and underlying data establishes the "allowable" range of values for R/RR ratios that establish whether classes are paying their fair share?

Elenchus Response:

There is no statistical method that establishes the allowable range of values for R/RR ratios to determine if a customer class is paying its fair share of costs imposed on the utility.

The range is recognition of the fact that cost allocation studies are more art than science and different methodologies can be used by utilities to apportion shared assets and expenses amongst customer classes. Different jurisdictions use different ranges around the R/RR ratios in order to determine if a customer class is paying its fair share of costs. The appropriate ratio is a matter of judgment.

<u>SIECA Query 3.7</u>

Please explain how and why the R/RR ratios tabled in the last four SaskPower Rate Applications that were produced using the existing SaskPower Cost of Service models have consistently placed the R/RR ratios for oilfield, power and commercial class customers at the high end of the "allowable" range and residential class customers are at the low end of the "allowable" range?

SaskPower Response:

The methodologies used in SaskPower's Cost of Service models are generally accepted methodologies to Functionalize, Classify and Allocate shared assets and expenses to customer classes. There is no inherent bias in any of the methodologies used that favour one customer class over another class.

During the Rate Design process, that follows the apportionment of the revenue requirement to SaskPower's customer classes, SaskPower follows the practice of setting the R/RR ratios for Residential and Farm classes slightly below 1.00, the Reseller Class at 1.00, and all other classes slightly above 1.00 to limit the occurrences of Residential and Farm classes' R/RR ratios ever exceeding 1.00, which can occur, if there are significant shifts in SaskPower's cost structure between rate applications. A range of revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions (see SaskPower's response to Query 3.3) as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs. The Saskatchewan Rate Review Panel (SRRP), which oversees SaskPower's rate applications, has consistently approved of this practice since 2001.

Elenchus has previously advised SaskPower (2012) that ratios within the acceptable range are deemed not to represent cross-subsidization, as conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to how shared assets are used by various customer groups. Hence, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives a subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

4. SaskPower COS Objectives — Economic Efficiency

The Elenchus draft report on Page 7 states, "***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).”***

SIECA Query 4.1

Please define "reasonable" as it relates to the above statement.

Elenchus Response:

Reasonable prices are prices that reflect the costs imposed by customers on the utility as determined by a cost allocation study (i.e., R/RR ratios within the accepted range), subject to additional practical considerations such as:

- The rates are sufficient to recover the prudently incurred costs of the utility,
- The rates design does not encourage waste of resources, and;
- The rates do not pass judgment on the type of use of the energy

5. Generation Classification Methodologies

Various generation classification methodologies are discussed in Pages 13-17 of the Elenchus draft report. The statement "***The choice of specific methodology should reflect the utility's circumstances."*** appears on Page 13 of the report.

SIECA Query 5.1

Please describe and explain what is meant by "utility circumstances".

Elenchus Response:

Utility circumstances include:

- Generation, transmission and distribution asset mix,
- Customer power consumption throughout the year,
- Customer classes served by the utility, e.g. Urban, Rural, and
- History of the utility with respect to rate structures used and customer classes served

SIECA Query 5.2

Please identify the specific SaskPower circumstances which Elenchus considered in determining its generation classification method recommendation and explain how the circumstances Elenchus considered accurately reflect SaskPower generation investment cost causality.

Elenchus Response:

Elenchus considered SaskPower's customer consumption profile in determining the generation classification methodology recommended.

A classification methodology based on customer consumption provides more stable classification results over time than a generation classification method based on generation assets, whose initial purpose may change over time, reflecting change in operational circumstances and/or Government policy.

SIECA Query 5.3

Please explain how the Average and Excess method captures the cost causality related to a utilities decision to invest additional generation capital in order to reduce fuel consumption.

Elenchus Response:

The Average and Excess method is based on customer consumption as the cost causality driver; it is not intended to reflect historical decisions to invest additional capital that may have been made for many reasons that may or may not be relevant in the current circumstances.

SIECA Query 5.4

On Page 14 of the Elenchus draft report a Table 1: Classification methodology. used for generation assets and expenses appears. Please define what "System Load Factor" means as a methodology. Please provide a revised Table 1 wherein the methodologies in the table match those discussed in the narrative of the Elenchus report or provide additional narrative which explains the methodologies listed in the Table I.

Elenchus Response:

System Load Factor is the relationship between average power demand and maximum power demand. Average power demand is the annual power demand on the system divided by the number of hours in the year. Maximum power demand is the maximum hourly demand imposed by customer consumption on the utility system at the time of maximum aggregate power demand in the year.

Table 1 below includes, in highlighted form, the classification methodologies described in Section 5.1 of Elenchus report.

Table 1: Classification methodology used for generation assets and expenses		
Methodology	Number of respondents	Percent of Respondents
Set by regulation	1	10
Average and Excess System Load Factor	4	40
100% demand	1	10
Peak and Average 3 CP Peak and Average	1	10
Fixed and Variable	1	10
NA	2	20
Totals	10	

SIECA Query 5.5

With regards to the Table 1: Classification methodology used for generation assets and expenses; Elenchus' utility survey data appended to its report shows that 2 of the 8 utilities responding (25%) classify 100% of generation plant as demand. Table I incorrectly shows only 1 of the 8 utilities classify 100% of generation plant as demand. Explain why Elenchus has ignored the 100% demand classification alternative in its analytical work, in its discussion of alternatives and in its recommendations to SaskPower.

Elenchus Response:

Consumers Energy classifies hydroelectric generation using the fixed and variable method, not 100% demand as SIECA assumes in its question. Consumers Energy responded: *"Fixed costs are considered demand related (including labor costs) and variable costs are considered energy related".*

Consumers is included in Table 1 as using the Fixed and Variable method.

Elenchus did not consider the 100% demand classification as an appropriate classification to be recommended for SaskPower, because Elenchus considers that utilities use generation assets to satisfy both demand and energy requirements, not just demand requirements.

SIECA Query 5.6

Does Elenchus believe that a sample size of eight utilities (2 of the 10 are shown as NA) provides a statistically significant representation of utility generation asset and expense classification methodology?

Elenchus Response:

Elenchus does not claim to have a statistically significant representation of utility generation and expense classification methodology.

Elenchus includes in its report the utilities that were contacted and that agreed to respond to the survey conducted.

SIECA Query 5.7

On Pages 15-17 of the Elenchus draft report the following four tables appear; Table 2: Classification of Hydro generation costs to demand, Table 3: Classification of Baseload Steam generation costs to demand, Table 4: Classification of Baseload Combined Cycle generation costs to demand, and Table 5: Classification of Combustion Turbine generation costs to demand. Please explain how and why Elenchus chose the percentage breakpoints in shown in column 1 of these four tables.

Elenchus Response:

There is no particular reason to use the percentage breakpoints shown on tables 2 to 5. Any breakpoint can be used.

SIECA Query 5.8

Did Elenchus attempt to find a correlation between the percentage classified as demand and the generation mix of the utility?

Elenchus Response:

No.

SIECA Query 5.9

Does Elenchus agree that a majority of the responding utilities under each of the four generation cost categories shown in Table 2, Table 3, Table 4 and Table 5 classify higher percentages to demand than would SaskPower under the Elenchus recommendation to utilize the Average and Excess load factor classification method? If no, please explain the Elenchus rationale for disagreement. If yes, please explain how the survey data is reconcilable with the recommendation to use Average and Excess method.

Elenchus Response:

Elenchus did not base its recommendation on a classification methodology to be used by SaskPower on the results of the survey.

Elenchus considers that cost causality principles require that the utility reflects its own circumstances in its cost allocation study and what is used by other utilities may not necessarily reflect how SaskPower electricity system operates and how its customer classes use the SaskPower system.

SIECA Query 5.10

Page 31 of the Elenchus draft report states, "**Based on the results of the survey, seven out of eight utilities classify hydroelectric generation as at least 35% demand related. The eighth utility classifies hydroelectric generation as 34% energy' related**." This statement is misleading and does not match the survey results and narrative on Page 31 and 32 that is captured in the table as follows:

% Classified to Demand	Hydroelectric	Baseload Steam	Combined Cycle	Combustion Turbine Units
Survey Average	64%	77%	100%	81%
SaskPower	19%	52%	82%	100%

A comparison of SaskPower's demand classification percentage with Elenchus' survey averages shows that SaskPower's demand classification percentages are substantially below the survey averages for 3 out the four generation types. Why is this conclusion not stated in your study?

Please explain how and why (despite the obvious disparities above) Elenchus in the draft report recommends an alternative classification methodology which reduces even further that portion of generation cost classified as demand.

Elenchus Response:

After reviewing the Elenchus draft report and the survey responses, two typo corrections need to be made:

1. On page 31, in the sentence: “Based on the results of the survey, seven out of eight utilities classify hydroelectric generation as at least 35% demand related. The eighth utility classifies hydroelectric generation as 34% demand ~~energy~~' related." (demand replaces the word energy), and
2. The survey response from Hydro Quebec in Appendix B to the percentage of Hydroelectric generation that is demand related should read “34.4% based on 2013 Load Factor” instead of “N/A”.

Elenchus disagrees with the table interpretation that the survey average of demand related hydroelectric generation is 64%.

The number of utilities that participated in the survey is too small and deriving an average gives misleading information and can lead to the wrong conclusion. The range of responses is so wide that calculating an average of the responses gives the wrong impression on what utilities are doing. Elenchus’ view is that the breakdown shown on the table is a better representation of the dispersion of the answers than calculating an average of the responses.

Please see response to Query 5.9.

6. Transmission investment versus generation investment

Transmission classification methodology is discussed in Pages 17-18 of the Elenchus draft report. The statement "***Transmission costs are usually classified as 100% demand related since transmission capacity is planned to accommodate the maximum system demand.***" appears on Page 17 of the report.

SIECA Query 6.1

Is SaskPower's generation capacity planned to accommodate the maximum system demand? If so, explain why generation investment should not also be classified as 100% demand.

Elenchus Response:

Elenchus understands that SaskPower generation capacity is built to accommodate both the maximum demand imposed on the generation system as well as the energy requirement of customers. That is the reason that Elenchus does not recommend classifying generation assets and expenses as 100% demand related.

In general, it would be feasible to plan a generation fleet at lower cost that is sufficient to meet peak demand but not the total energy requirement, or the reverse. However, the fleet must be planned to meet both requirements. On the other hand, any transmission system that is designed to meet peak demand will, by definition, accommodate the annual energy requirement.

SaskPower Response:

SaskPower plans for adequate resources to meet anticipated energy, peak load and reserve requirements. Our reserve requirement is to maintain 13% Peak Reserve Margin i.e. level of installed capacity has to be sufficient to meet maximum demand plus additional 13%. North American utilities typically plan for a reserve margin in the range of 10 % - 15 % to account for higher than expected demand and unforeseen events. In addition to deterministic approach to meet demand as explained above, SaskPower has also developed a Probabilistic Model to meet the energy requirements utilizing Monte Carlo simulations. Monte Carlo method is a standard in utility industry to capture random events such as random outage of a generating unit due to failure, and calculates reliability of a system in terms of Expected Unserved Energy, which has to be within an acceptable level as determined through resource adequacy analysis.

7. **Demand Allocators — 1 Coincident Peak Method**

Page 23 of the Elenchus draft report discusses the 1 CP Method to allocate demand costs. The report states "***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"***.

SIECA Query 7.1

Does Elenchus acknowledge that the 1 CP method discussed applies only to the demand portion of generation costs and that customers using less electricity at the system peak will still pay a significant portion of those generation costs classified as energy?

Elenchus Response:

The statement about the disadvantage of the 1 CP method relates to the allocation of Transmission related assets and expenses. Transmission assets and expenses are usually classified as 100% demand related.

Elenchus agrees that customers that use less electricity at the time of the system peak still pay generation assets and expenses that are classified as energy related.

SIECA Query 7.2

Does Elenchus acknowledge that that (sic) customers who can reduce their consumption during the system peak actually lower the system peak and reduce the need for generation capacity and thereby help lower the generation cost for all customers?

Elenchus Response:

As long as the utility can count on the customer never consuming during the system peak, the system peak would be lower when compared to a situation where the customer does not reduce consumption during the system peak.

If the customer does not reduce consumption at the time of the system peak, based on cost causality principles, the customer that caused the higher system peak would be responsible for the additional generation costs. Other customers' costs should not change because another customer is creating a higher system peak.

Since capacity costs are not avoidable for the utility in the short run, when a customer (or class) reduces its peak demand and that reduction is reflected in a subsequent cost allocation study, total costs are not reduced; hence, costs are shifted from the customer or class that has reduced its demand to other customers.

SIECA Query 7.3

Does Elenchus have any evidence that SaskPower customers deliberately reduce their consumption at peak hours in order to avoid paying their fair share of system costs? If so, please provide the supporting class or customer demand measurement information that supports this assertion.

Elenchus Response:

Elenchus has no such evidence in SaskPower's case, but based on Elenchus experience, larger customers that can control or reduce their power consumption at times of system peak if given the appropriate price signal, will shift consumption in order to avoid incurring higher system utilization charges for Generation and/or Transmission.

SIECA Query 7.4

With respect to Table 16: Allocation Method for Generation Demand Costs found on Page 24 of the Elenchus draft report please explain why none of the utilities surveyed uses a 2CP allocation method for demand portion of generation costs?

Elenchus Response:

Elenchus does not know why none of the utilities uses the 2 CP allocation method. Elenchus can only speculate that the reason is that 2 CP does not reflect the utility circumstances.

SIECA Query 7.5

Given that the 2CP allocation method currently used by SaskPower could be semantically described as a 30CP method (3 annual winter and 3 annual summer peaks over 5 years); please provide a specific explanation of how peaks are determined, selected and timed for the 3CP methods used by NB Power and NS Power and for the 4 CP methods used by BC Hydro and Consumers Energy.

Elenchus Response:

Elenchus does not agree that "the 2CP allocation method currently used by SaskPower could be semantically described as a 30CP method (3 annual winter and 3 annual summer peaks over 5 years)". In the case of other utilities, including those mentioned in the question, the cost allocation study is based on a forecast year that is normalized. In forecasting peak demand for a 2CP method, the forecast will be based on historical data for multiple years (often more than 5) and considers different peak hours in different years. The use of historical information by SaskPower is necessary to derive an appropriate normalized value that is equivalent to the forecast value used by other utilities.

SIECA Query 7.6

Please confirm that BC Hydro, Manitoba Hydro, Hydro Quebec, NL Power and NS Power (5 of 8 responding utilities) all allocate generation demand costs using a winter only coincident peak method?

Elenchus Response:

Based on the responses to the survey we can confirm that Manitoba Hydro uses 50 winter hours, Hydro Quebec uses 300 hours, (assume they are all in the winter), NL Power responded 1 CP, (assume that NL Power is winter peaking) and NS Power responded 3 Winter CP.

BC Hydro responded 4 CP without stating which months.

Utilities with winter peaking systems (i.e., summer peaks that are significantly lower than their winter peaks) appropriately use only winter hours in deriving their peak demand allocator.

8. <u>Equivalent Peaker Method</u>

The Equivalent Peaker classification method is discussed on Page 36 of the Elenchus draft report. The statement "***First, standard costing data for fossil plants is no longer available.”*** appears on Page 36 of the report.

<u>SIECA Query 8.1</u>

Please explain the basis and provide the support for this statement given the availability of generation cost data published by the Energy Information Administration (EIA).

SaskPower Response:

The “Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations” establishes a performance standard for the intensity of CO2 emissions from regulated units using coal as a fuel. A new unit (commissioned on or after July 1, 2015) must not emit on average an intensity of more than 420 tonnes CO2 emission per GWh of electricity produced in a calendar year. As a result, SaskPower is not actively planning or updating the cost estimate for a new conventional coal unit as this technology will violate these regulations.

The cost estimate for this generation technology was based on a 2009 cost estimate. An annual escalation factor of 2% has been used to update the cost to current dollars. The new coal unit without carbon capture and storage cost estimate generated by the Energy Information Administration (EIA) is a 650 MW Ultra Supercritical Coal unit. This generation option and the cost data is not applicable for a Saskatchewan case for a number of reasons including; it is significantly larger in capacity (650 MW vs 350 MW) than can be currently built in Saskatchewan due to limitations for the largest single contingency, it is not designed using our local coal resource (lignite), its costs are specific to a US location and US costs.

<u>SIECA Query 8.2</u>

Is Elenchus aware that some utilities use original generation investment cost inflated by the Handy-Whitman index to establish the relative cost of generation alternatives? Please explain why this method is not available to SaskPower.

Elenchus Response:

Yes, Elenchus is aware that some utilities use this approach. Elenchus' view that the Equivalent Peaker Method is not an appropriate basis for classifying generation costs for the SaskPower cost allocation study is not based on data availability. Other practical and conceptual concerns are sufficient to reject this method.

SaskPower Response:

The Handy-Whitman index appears to be an index produced by a company called Whiteman, Requardt and Associates. This company has only US locations listed on its website. To our knowledge SaskPower hasn't used this index or worked with this company. Given its US location and website information it is not apparent that this company produces Canadian based indexes.

SIECA Query 8.3

The statement "***Furthermore, environmental regulations required SaskPower to invest significant capital in coal retrofitting measures that impact the results of applying SaskPower's current Equivalent Peaker method. The resulting change in the calculated demand-energy split is not a reasonable reflection of cost drivers for SaskPower's generation assets and expenses***." appears on Page 36 of the report.

Please provide an example of how SaskPower's investment in coal generation plant retrofitting impacts its Equivalent Peaker calculation and demonstrate why the result is not a reasonable reflection of SaskPower's generation assets cost drivers.

SaskPower Response:

The capitalization of the Boundary Dam Carbon Capture and Storage plant in 2014 had the following impact on the Demand/Energy classification ratios for generation plants produced by the Equivalent Peaker Method:

	2013	2014	Variance
Demand Related	52.2%	42.5%	9.8%
Energy Related	47.8%	57.5%	9.8%
Total	100.0%	100.0%	0.0%

The capitalization of one generation asset in 2014 caused a nearly 10% change in the Demand/Energy ratio. If SaskPower continues to use the Equivalent Peaker Method to calculate the Demand/Energy ratio, the same volatility can be expected every time a major generation asset is capitalized.

9. Elenchus Recommendation on Classification Method

Despite presenting no quantitative evidence for the unsuitability of the Equivalent Peaker classification method, Elenchus proceeds to recommend a change to the classification method on Page 37 of its draft report. The statement "***Two alternative methodologies were explored by Elenchus with assistance from SaskPower staff: Average and Excess and 2 CP and Average. Both alternatives are load based options.*** " appears on Page 37 of the report.

SIECA Query 9.1

Please explain why Elenchus chose to explore these two methodologies and not the other methodologies identified in the survey?

Elenchus Response:

Elenchus chose these two alternatives because they reflect the need to supply both demand and energy, are based on customer consumption which provides more stable results than the Equivalent Peaker method and reflect SaskPower's system operations.

SIECA Query 9.2

The statement "***The Average and Excess method, 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 in order to develop the necessary customer consumption data.***" appears on Page 37 of the Elenchus draft report.

Please provide the customer consumption data that was provided by SaskPower as referenced in the statement above.

SaskPower Response:

Please see the associated Excel file (SIECA Query 9.2 response.xlsx) which provides the calculation details of both the Average & Excess and the 2CP & Average splits.

SIECA Query 9.3

Please explain the difference between customer class information and rate code information. Why was customer class information not available?

SaskPower Response:

Customer classes are comprised of rate codes. Rate Codes are the rates that we charge to a specific group of customers for their electrical usage. Examples include the Power Class rates (i.e., E22, E23, E24, E25, E82, E83, E84, & E85). Together these individual rate codes, when combined, make up the Power – Published customer class. Another example would be the Residential class that is made up of rate codes E01, E02, E03, & E04. SaskPower conducted its analysis at the rate code level and then combined them into their appropriate customer classes to summarize the results.

SIECA Query 9.4

The statement "***The alternative Average and Excess method produced a 78.3% of energy related generation costs. This is not surprising as SaskPower has a relatively high system load factor above 70%. The 2 CP and Average method produced a proportion of energy related costs of 43.9%.*** "appears on Page 37 of the Elenchus draft report.

In addition to the request made in SIECA Query 1.4 herein for the version of the 2015 Base Embedded Cost of Service Study report that has been modified to utilize the 2CP and Average generation classification method: please provide the specific data and calculations which result in the classification percentages referenced in the statement above (in Excel format with functioning formulas).

SaskPower Response:

Please see the associated Excel file (SIECA Query 9.2 response.xlsx) which provides the calculation details of both the Average & Excess and the 2CP & Average ratios.

SIECA Query 9.5

The statement "***Based on costs causality principles and reflecting SaskPower's high load factor system the percentage of energy related generation costs should be higher than currently used in SaskPower's cost allocation study.*** " appears on Page 37 of the Elenchus draft report.

Is it Elenchus' understanding that SaskPower makes generation investment decisions based on system load factor?

Elenchus Response:

The system load factor is the ratio of average energy over peak demand. Elenchus understands that SaskPower's generation investment decisions are made in order to satisfy maximum demand imposed on its system as well as to satisfy energy requirements. Hence, the investment decisions will ultimately be affected by the load factor. For example, a system with a 90% load factor would certainly require a different generation fleet than a system with a 50% load factor, in order to minimize generation costs.

SaskPower Response:

Please also see SaskPower's responses to SIECA Query 2.3 and 6.1.

SIECA Query 9.6

As part of its study did Elenchus make specific comparisons of the classification methods used by other high load factor utilities? If so, please identify the utilities, provide their load factor information and provide the support data and analyses underlying the comparison.

Elenchus Response:
No.

10. Recommendation to Consolidate 138 kV and 230 kv Rate Classes

SIECA Query 10.1

Please confirm that Elenchus and SaskPower will revisit the recommendation to consolidate the 138 kv and 230 kv rate classes as requested verbally in the public meetings by Meadow Lake Mechanical Pulp Ltd., Mosaic Potash and other SIECA member companies that are or will be served at 230 kV. The cost to serve customers at 230 kV is unquestionably lower than serving at lower transmission service voltages. Therefore, SIECA encourages Elenchus and SaskPower to be consistent with their commitment to cost causality and reverse this recommendation and proceed with designing and implementing appropriately lower 230 kV rates.

SaskPower Response:

SaskPower confirms it will, along with Elenchus, revisit the recommendation to consolidate the 138kV and 230kV rates.

11. <u>Winter-Summer Allocation (2CP)</u>

The allocation of generation demand costs using multiple and seasonal coincident peak methodologies are discussed in Pages 44-47 of the Elenchus draft report. The statement "***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.***" appears on Page 44 of the report.

Further on Page 45, the following statement is found, "***On this basis, it may be more appropriate to view the summer peaks as the prime driver that causes capacity costs to be incurred, at least for those facilities that are most affected by the higher summer temperatures. "***

<u>SIECA Query 11.1</u>

Please identify the specific SaskPower generation facilities for which summer peaks are/were the primary investment decision driver, quantify their share of the total generation capital cost and explain why it is appropriate to base the entire generation demand cost allocation methodology on the operating characteristics of those facilities.

SaskPower Response:

SaskPower has undertaken no investment in generation assets that were specifically made to meet only the summer peak. Generation may be triggered by the winter peak (which the summer peak is approaching due to lower capacity from wind in the summer and higher thermal de-rates to the natural gas generation) but the generation added is relied upon year round to help schedule units to come off line for regular maintenance and to meet demand during times when generators go on unplanned forced outage, and during un-forecasted high demand.

<u>SIECA Query 11.2</u>

Is Elenchus aware of any SaskPower generation investment that was specifically documented and justified on the basis of meeting a summer peak? If so, please provide a summary of the capital expenditure authorization for such project(s).

SaskPower Response:

Please see SaskPower's response to SIECA Query 11.1.

SIECA Query 11.3

On Page 45 of the Elenchus draft report, the following statement is found, "***Based on the results of the survey where many utilities use more than one peak as allocator and taking into consideration the information from SaskPower's system planners, Elenchus continues to support the use of the 2 CP allocator by SaskPower as a demand allocation methodology for generation, transmission and primary distribution lines."***

Please provide the system class load and demand information and any other SaskPower information which Elenchus relied upon in its decision to recommend the continued use of the "2CP" allocator.

SaskPower Response:

The continued support of the "2CP" allocator came in part from discussions with Subject Matter Experts at SaskPower from the Transmission, Distribution, and Power Production groups who explained details on how SaskPower's system operates that were of assistance to Elenchus; as well as analysis of SaskPower's system load information.

Please see the Excel file 'SIECA Query 11.3 response – SPC Win-Sum system load.xlsx'

SIECA Query 11.3 (sic should be 11.4)— Information Request

On page 46 of the Elenchus draft report there is a Table 30 Revenue to Revenue Requirement Ratios 2015 Data that illustrates the R/RR ratios for different combinations of "2CP" averaging or configuration. The table's ratio data shows that as more "averaging or smoothing" is done to the CP data the Revenue Requirement from high load factor customers increases. Despite Elenchus' commitment to the 2CP winter-summer allocation method, they have failed to table any information proving that SaskPower makes generation investment decisions based on summer peaks.

Therefore, SIECA requests that SaskPower conduct a COS model scenario analysis using a true 1CP winter generation demand cost allocator and provide the comparative results by adding a column to Table 30 for the 1 CP winter peak scenario and providing a version of the 2015 Base Embedded Cost of Service Study report that has been modified to utilize a 1 CP generation demand cost allocation method and that maintains the existing Equivalent Peaker generation cost classification methodology. This request has been denied previously by Elenchus in this proceeding, however SaskPower can (and should) undertake this analysis to facilitate due diligence and assessment of impacts by all customers.

SaskPower Response:

It appears SIECA has misinterpreted the results on "Table 30 Revenue to Revenue Requirement Ratio 2015 Data" on Page 46 of the Elenchus draft report.

The results of comparing the average of the single winter and summer peak over 5 years to the 3 highest winter and summer peaks over 5 years are shown in the table below:

Customer Class	**5 Year – Single Winter & Summer**	**5 Year – 3 Winter & 3 Summer**	**Difference**
Residential	0.98	0.96	-0.02
Farms	0.97	0.98	0.01
Commercial	1.02	1.02	-0.01
Power	1.01	1.02	0.02
Oilfields	1.03	1.03	0.01
Streetlights	0.86	0.86	0.00
Reseller	0.96	0.95	-0.01
Total	**1.00**	**1.00**	**0.00**

Note – Some values may not sum to indicated totals due to rounding

The implication of the higher R/RR ratios for the Power and Oilfield classes under the 5 year average of the 3 winter and summer peaks is they would likely experience lower increases than they would have received under the 5 year average of the single winter and summer peaks.

The implication of the lower R/RR ratios for the Residential, Commercial and Reseller classes under the 5 year average of the 3 winter and summer peaks is they would likely experience higher increases than they would have received under the 5 year average of the single winter and summer peak.

The first methodology yields an R/RR ratio of 1.01 for the Power Class and, when using the 5 year average of the 3 winter and summer peaks, the ratio increases to 1.02, indicating that the revenue requirement for the Power Class under the 3 winter and summer peaks has decreased. This is confirmed in the table below:

Customer Class	5 Year – Single Winter & Summer	5 Year – 3 Winter & 3 Summer	Difference ($millions)	Impact (%)
Residential	$500.3	$509.5	$9.2	1.8%
Farms	$163.3	$162.2	-$1.1	-0.7%
Commercial	$422.7	$424.9	$2.2	0.5%
Power	$605.8	$596.6	-$9.2	-1.5%
Oilfields	$324.3	$322.3	-$2.0	-0.6%
Streetlights	$17.5	$17.5	$0.0	-0.1%
Reseller	$93.9	$94.9	$1.0	1.0%
Total	**$2,127.7**	**$2,127.7**	**$0.0M**	**0.0%**

Note – Some columns may not sum to indicated totals due to rounding

The results show that “averaging and smoothing” multiple data points over 5 years is more beneficial to the Power and Oilfield classes in this instance. They indicate that, with all other factors held constant, SaskPower would recover $11.2 million less from the Power and Oilfield class using the 5 year average of the 3 winter and summer peaks than it would using the 5 year average of the single winter and summer peaks.

For the second part of SIECA’s submission, Elenchus previously declined this request as they felt the use of a 1CP allocator was not appropriate, given their prior recommendation to SaskPower to continue its use of 2CP demand. However, in the interests of transparency for this study, please see the provided copy of the ‘2015 Base Embedded Cost of Service Study ReportWithTitlePage – SIECA Query 11.3.pdf’ which was calculated under 1 CP with all original methodology, dated May 30, 2017.

In particular, please take note when referring to Table 3 – Summary of Revenue to Revenue Requirement Ratios of the report, on page 10. In comparing the results of Table 3, to those in the original 2015 Base Embedded Cost of Service Study, dated October 14, 2016, which was prepared using 2 CP with all original methodology, the Allocated Revenue Requirement for the Power Class of Customers are as follows:

2015 Base Embedded Cost of Service Study ($ Millions)					
	Revenue	Allocated		Revenue to Revenue	
Customer Class		Revenue Requirement		Requirement Ratio	
	(Actuals)	1 CP	2 CP	1 CP	2 CP
Power - Published Rates	$ 464.5	$ 446.1	$ 440.6	1.04	1.05

It is worth nothing that the results calculated using 2 CP actually results in an Allocated Revenue Requirement for the Power Class of customers approximately $5.5 million less than the results calculated using 1 CP. Similarly, the Revenue to Revenue Requirement Ratios calculated using 2 CP yields 1.05 for the Power Class versus 1.04 calculated using 1 CP.

It is important for all parties to understand that a COS study is not an exercise in running hypothetical scenarios to find which ones benefit certain customers the most; but rather to select a methodology that best fits the utilities' circumstances and operating conditions and manage the outcomes of that methodology accordingly.