Final Report

Cost of Service Methodology Review

British Columbia Hydro and Power Authority

December 20, 2013

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Mr. Craig Godsoe
Sr. Solicitor and Counsel, Legal Services
British Columbia Hydro and Power Authority
333 Dusmuir, 16th Floor
Vancouver, B.C. V6B 5R3

Subject: **Final Report – 2013 Cost of Service Methodology Review**

Dear Mr. Godsoe:

SAIC Energy, Environment and Infrastructure, now called Leidos Engineering (Leidos), in conjunction with Cuthbert Consulting Inc. is pleased to submit this final report for the 2013 Cost of Service Methodology Review prepared for the British Columbia Hydro and Power Authority (BC Hydro). This report sets forth and summarizes the methodology, assumptions, analyses, and final results of the study.

The preparation of this study was a collaborative effort between BC Hydro, Leidos, and Cuthbert Consulting staff. I wish to express our appreciation for the friendly cooperation and assistance to all of those who provided the information and reviews necessary to successfully complete this study.

Once again, we appreciate the opportunity to be of service to BC Hydro.

Sincerely,

Leidos Engineering, LLC

Laurie A. Tomczyk

Laurie A. Tomczyk. P.E.
Project Manager

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Background

In March 2007, BC Hydro filed its 2007 Rate Design Application (2007 RDA) with the British Columbia Utilities Commission (BCUC). The 2007 RDA was BC Hydro's first general RDA since 1991, and it was prepared to update BC Hydro's rates and tariffs to reflect then current conditions and generally accepted rate design criteria. The 2007 RDA included an updated Cost of Service (COS) analysis that was used as a primary factor in adjusting rates in the RDA.

As described in its 2007 RDA, BC Hydro completes a two-phased process as part of its review of its rates and charges to its customers. The first phase of this ratemaking process is preparation of a revenue requirements analysis that is filed and reviewed in a proceeding before the BCUC. As such, the 2007 RDA began with an updated BCUC-approved revenue requirement for Fiscal Year 2008. This approved revenue requirements analysis served as the basis for the 2007 RDA.

The second phase of BC Hydro's ratemaking process is its preparation of both a COS study, which allocates and assigns its entire revenue requirement to the rate classes BC Hydro serves, and a rate design study, which modifies its rates and charges consistent with its policy objectives. The COS analysis results are a key component of BC Hydro's rate design. As detailed in the 2007 RDA, the principal focus of the rate design effort included (1) that each customer class bear a fair share of the costs necessary to serve the class, with fair represented as reasonable revenue to cost (R/C) ratios within a 90 percent to 110 percent range, (2) efficiency as indicated by rates providing pricing signals to encourage conservation, and (3) simplicity as indicated by clear, transparent, and cost-effective implementation.

A rate review proceeding occurred during the course of 2007 and ended with a BCUC Decision issued in October 2007. The 2007 BCUC Order G-130-07 directed BC Hydro to make a number of significant changes to its COS methodology and the resulting rates, and to investigate further several issues before it filed its next RDA. Since the Decision was issued in the 2007 RDA, BC Hydro has updated its COS analysis annually and filed these updates with the BCUC. Also, BC Hydro has undertaken a number of actions to implement the directives from the Decision.

As it began its efforts to prepare for a possible new RDA in 2013 or 2014, BC Hydro retained SAIC Energy, Environment & Infrastructure (SAIC) in October 2012 to complete an independent review of its COS methodology and a jurisdictional review of COS methodologies used by other selected North American electric utilities. The purposes of this effort were to provide guidance on modifications and improvements that BC Hydro may consider implementing in its COS methodology.

Key Issues for Review

In its October 2007 Decision issued in the 2007 RDA proceeding, the BCUC reviewed a number of issues that were raised during the course of the proceeding, and the regulatory and policy framework that guided its findings. As a result of reviewing the BC Hydro COS methodology and the BCUC 2007 decision, SAIC identified a number of key issues that would constitute the focus of our assessment as well as the focus of the jurisdictional review. These issues were reviewed with BC Hydro staff and several additional items were identified that were of concern to the utility. The primary items of concern included the following:

- What is the appropriate methodology for classifying and allocating BC Hydro’s hydro resources?
- What is the appropriate methodology for classifying and allocating BC Hydro’s thermal resources?
- What is the appropriate methodology for classifying and allocating BC Hydro’s independent power producer (IPP) and other purchased power costs?
- What is the appropriate methodology for classifying and allocating net power sales income obtained from BC Hydro’s Powerex wholesale power subsidiary?
- What is the appropriate methodology for classifying and allocating BC Hydro’s transmission resources?
- What is the appropriate methodology for classifying and allocating BC Hydro’s distribution assets and costs, and what role should minimum system studies and zero intercept studies have on this classification and allocation?
- What is the appropriate methodology for functionalizing, classifying, and allocating BC Hydro’s demand side management (DSM) costs?
- What are suitable guidelines or objectives for rate rebalancing, including what is the appropriate target range of R/C ratios?

Scope of Review

The specific scope of work conducted as part of this review included the following tasks:

- SAIC prepared a comprehensive data request for documents related to BC Hydro’s COS methodology and ratemaking process, and completed both an initial review of these documents and a more in-depth review of certain of the data during the course of our review to better understand the issues of concern to BC Hydro and the basis for the current COS methodology.
- SAIC staff attended a series of meetings in Vancouver, British Columbia, with BC Hydro staff reviewing the requested documents, learning more about the

financial and operational data sources available to prepare the COS analyses, and BC Hydro's policies and practices that impact its ratemaking practices and objectives.

- SAIC conducted a comprehensive review of the COS analyses, models, and spreadsheets that are used in BC Hydro's ratemaking process, focusing the review on several areas identified by BC Hydro staff to be of high interest. This review included relevant and recent BCUC COS-related proceedings and decisions, BC Hydro's current COS model and a minimum system and zero intercept analysis completed in 2010 with a focus on the functionalization, classification, and allocation of costs in BC Hydro's current COS model.
- SAIC and BC Hydro staff jointly completed a jurisdictional review of COS methodologies used by North American electric utilities that were selected based on criteria for similarity and relevance to BC Hydro. Based on these criteria, rate case filings or studies by nine utilities in ten separate jurisdictions were selected to include in the jurisdictional review.
- SAIC completed a summary report on the COS methodology review findings, including the jurisdictional review results, and recommended modifications to the COS methodology for BC Hydro's review and consideration.

Recommendations

The results of the jurisdictional review showed that a wide variety of approaches are used to classify and allocate generation, transmission, and distribution costs. In addition, a variety of approaches are used for rate rebalancing. Based on the results of the review of COS methods identified in the jurisdictional review as well as the prior experience of the SAIC review team, a number of observations were made and recommendations developed for BC Hydro staff to consider modifying when preparing its COS analysis for its next COS study. The recommendations are provided below.

Our review found that the overall COS approach used by BC Hydro in the 2007 RDA, as well as the current COS approach that incorporates the changes required by the 2007 BCUC order, are generally consistent with standard embedded cost of service methodologies used by other electric utilities in North America with one exception. Customer care costs are typically classified as 100 percent customer-related, but BC Hydro's customer care costs are currently classified as 65 percent demand-related and 35 percent customer-related in the BC Hydro COS model as a result of the outcome from the 2007 RDA. Unless specifically addressed below, therefore, the implication is that the COS methodologies currently employed by BC Hydro are generally acceptable and no other changes to the COS methodology are recommended.

Generation COS Methodologies

- We recommend that BC Hydro consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.
- For allocating demand-related hydro costs, we recommend BC Hydro first analyze how hydro units are designed or being used to serve peak loads throughout the year. To the extent that the hydro plants are designed or used to meet peak loads throughout the entire year, then a 12 coincident (CP) method is appropriate. If the hydro plants are primarily designed or used to help meet peak loads during only a few months of the year, then methods such as 3 CP or 4 CP would be more appropriate.
- As an alternative approach option for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.
- We recommend that BC Hydro continue to classify peaking thermal plant costs as demand-related and also classify associated operation and maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.
- For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the CP demands in the months when the thermal plants are primarily used.
- We recommend that BC Hydro modify the classification of IPP and other purchased power obligations to reflect either fixed versus variable payment obligations or capacity versus energy usage.
- We recommend that BC Hydro continue using the split between demand-related and energy-related generation revenue requirements, excluding subsidiary income, to classify subsidiary net income.

Transmission COS Methodologies

- For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, we believe it is most appropriate for the costs of these resources to be classified and allocated in the same manner as costs for the generation resources.
- For backbone or network transmission, we recommend BC Hydro's use of the current Demand Only method for classification should continue to be used. When selecting an allocation method, consideration should be given as to how these transmission assets are designed and used and BC Hydro's load patterns. It may be appropriate to sub-functionalize these transmission costs between areas, such as the southern interior and other areas, using different types of allocation factors for each. Based on testimony related to the 2007 RDA, it

appears that summer loads are of most importance to that portion of the BC Hydro system while loads during other times of the year may be of more importance for other parts of the system.

- For transmission/subtransmission assets that essentially serve as a radial high voltage distribution system, we recommend that the Demand Only method for classification should continue to be used and consideration should be given to using 1 non-coincident peak (NCP) as the demand allocator.

Distribution and Customer Care COS Methodologies

- We recommend BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.
- We recommend BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.
- We recommend if possible that BC Hydro consider using more direct assignment of distribution costs (e.g., transformers, services, and meters) based on fixed asset records, or consider using the weighted number of customers when calculating the allocation factors for transformer, services, and meter costs.
- We recommend BC Hydro review and revise the Distribution System Study to be more consistent with the theoretical foundation of the minimum system method and zero-intercept method as described in the *1992 NARUC Manual*, prior to its use by BC Hydro. As an alternative, we recommend BC Hydro consider classifying distribution substation, lines, and transformer costs as all demand-related and services and meter costs as all customer-related.
- We recommend that BC Hydro classify most, if not all, customer care costs as customer-related.

DSM COS Methodologies

- We recommend that BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro’s generation plant to transmission plant. As such, the functionalization approach would be consistent with the classification approaches.

Appropriate R/C Ratios

- We recommend BC Hydro consider adopting a range of reasonableness for customer class R/C ratios, with the goal of making changes in rate levels gradually over a several year period consistent with this and other ratemaking objectives when customer classes are outside of the target R/C range.
- We recommend BC Hydro consider more explicitly developing a policy for how rapidly customer classes should be moved towards this range of

reasonableness for R/C ratios with consideration also given to other ratemaking goals and objectives and the current legal limit on rebalancing (i.e., no more than two percentage points per year compared to the R/C ratio for that class immediately before the increase).

Sub-Functionalization

As indicated above, we think BC Hydro would benefit from greater sub-functionalization of its revenue requirements than is currently used in the COS model. We recommend BC Hydro consider adopting a greater level of detail in the breakdown of both operating costs and plant asset accounts in its COS model and analysis in order to avail itself to greater direct assignment of costs and greater transparency in assigning costs more accurately to its customer classes. It should be noted, however, that evaluating the feasibility of performing the sub-functionalization of costs required for several of these suggested approaches goes beyond the scope of this review.

Section 1
INTRODUCTION AND BACKGROUND

Purpose of Review

In October 2012, SAIC Energy, Environment & Infrastructure (SAIC) was engaged by British Columbia Hydro and Power Authority (BC Hydro) to prepare an independent review of its Cost of Service (COS) methodology and subsequently provide guidance on modifications and improvements that BC Hydro may consider implementing.

Scope of Review

The specific scope of work conducted as part of this review included the following tasks:

- SAIC prepared a comprehensive data request for documents related to BC Hydro's COS methodology and ratemaking process, and completed both an initial review of these documents and a more in-depth review of certain of the data during the course of our review.
- SAIC staff attended a series of meetings in Vancouver, British Columbia, with BC Hydro staff reviewing the requested documents, learning more about the financial and operational data sources available to prepare the COS analyses, and BC Hydro's policies and practices that impact its ratemaking practices and objectives.
- SAIC conducted a comprehensive review of the COS analyses, models, and spreadsheets that are used in BC Hydro's ratemaking process, focusing the review on several areas identified by BC Hydro staff to be of high interest. This review included relevant and recent British Columbia Utilities Commission (BCUC) COS-related proceedings and decisions, BC Hydro's current COS model and a minimum system and zero intercept analysis completed in 2010 with a focus on the functionalization, classification, and allocation of costs in BC Hydro's current COS model.
- SAIC and BC Hydro staff jointly completed a jurisdictional review of COS methodologies used by North American electric utilities that were selected based on criteria for similarity and relevance to BC Hydro.
- SAIC completed a summary report on the COS methodology review findings, including the jurisdictional review results, and recommended modifications to the COS methodology for BC Hydro's review and consideration.

Background

In March 2007, BC Hydro filed its 2007 Rate Design Application (2007 RDA) with the BCUC. The 2007 RDA was BC Hydro's first general RDA since 1991, and it was prepared to update BC Hydro's rates and tariffs to reflect then current conditions and generally accepted rate design criteria. The 2007 RDA included an updated COS analysis that was used as a primary factor in adjusting rates in the RDA.

A rate review proceeding occurred during the course of 2007 and ended with a BCUC Decision issued in October 2007. During the rate review process, a number of elements of BC Hydro's COS methodology were questioned and commented on by several interveners in the proceeding. Among the issues were the appropriate classification and allocation of generation, transmission, and distribution costs between BC Hydro's customer classes and target revenue to cost (R/C) ratios for rate design. The BCUC issued its Decision in the proceeding in October 2007, which directed BC Hydro to make a number of significant changes to its COS methodology and the resulting rates, and to investigate further several issues before it filed its next RDA.

Since the Decision was issued in the 2007 RDA, BC Hydro has updated its COS analysis annually and filed these updates with the BCUC. Also, BC Hydro has undertaken a number of actions to implement the directives from the Decision. As it began its efforts to prepare for a possible new RDA in 2013 or 2014, BC Hydro retained SAIC to complete this independent review of its COS methodology and jurisdictional review to help BC Hydro evaluate issues in preparation for the next COS study.

BC Hydro's Ratemaking Process and Cost of Service Methodology

As described in its 2007 RDA, BC Hydro completes a two-phased process as part of its review of its rates and charges to its customers. The first phase of this ratemaking process is preparation of a revenue requirements analysis that is filed and reviewed in a proceeding before the BCUC. As such, the 2007 RDA began with an updated BCUC-approved revenue requirement for Fiscal Year 2008. This approved revenue requirements analysis served as the basis for the 2007 RDA.

The second phase of BC Hydro's ratemaking process is its preparation of both a COS study, which allocates and assigns its entire revenue requirement to the rate classes BC Hydro serves, and a rate design study, which modifies its rates and charges consistent with its policy objectives. In the 2007 RDA, BC Hydro presented an embedded COS analysis that functionalized, classified, and then allocated the test year revenue requirement to the customer classes. Functionalization was used to separate the revenue requirement into generation, transmission, distribution, and customer care functions. These functional components were then classified as either energy-related, demand-related, or customer-related. Then these classified components were allocated to (1) residential, (2) small, medium, and large general service, (3) irrigation, (4) street lighting, and (5) transmission rate classes based on a number of allocation factors. Additional information on the COS methodology was provided in the 2007 RDA.

The COS analysis results are a key component of BC Hydro's rate design. As detailed in the 2007 RDA, the principal focus of the rate design effort included (1) that each customer class bear a fair share of the costs necessary to serve the class, with fair represented as reasonable R/C ratios within a 90 percent to 110 percent range, (2) efficiency as indicated by rates providing pricing signals to encourage conservation, and (3) simplicity as indicated by clear, transparent, and cost-effective implementation.

Key Issues for Review

In its October 2007 Decision issued in the 2007 RDA proceeding, the BCUC reviewed a number of issues that were raised during the course of the proceeding, and the regulatory and policy framework that guided its findings. As a result of reviewing the BC Hydro COS methodology and the BCUC 2007 decision, SAIC identified a number of key issues that would constitute the focus of our assessment as well as the focus of the jurisdictional review. These issues were reviewed with BC Hydro staff and several additional items were identified that were of current concern to the utility. The primary items of concern included the following:

- What is the appropriate methodology for classifying and allocating BC Hydro's hydro resources?
- What is the appropriate methodology for classifying and allocating BC Hydro's thermal resources?
- What is the appropriate methodology for classifying and allocating BC Hydro's independent power producer (IPP) and other purchased power costs?
- What is the appropriate methodology for classifying and allocating net power sales income obtained from BC Hydro's Powerex wholesale power subsidiary?
- What is the appropriate methodology for classifying and allocating BC Hydro's transmission resources?
- What is the appropriate methodology for classifying and allocating BC Hydro's distribution assets and costs, and what role should minimum system studies and zero intercept studies have on this classification and allocation?
- What is the appropriate methodology for functionalizing, classifying, and allocating BC Hydro's demand side management (DSM) costs?
- What are suitable guidelines or objectives for rate rebalancing, including what is the appropriate target range of R/C ratios?

SAIC Approach to the Review Process

The approach SAIC used in conducting this review included:

- Review documents and data provided by BC Hydro to better understand the issues of concern to BC Hydro and the basis for the current COS methodology.
- Conduct interviews with BC Hydro staff involved in functions of the utility, including generation, transmission, distribution, accounting, contracting, and administration to better understand the process of how BC Hydro obtains and delivers electricity to its customers.
- Complete the jurisdictional review to better understand how the issues of concern are handled by other utilities that are similar in operation to BC Hydro.
- Prepare an assessment of the strengths and weaknesses of the current BC Hydro COS methodology related to those issues and provide this assessment to BC Hydro for its review.

Overview of Report

The remainder of this report is organized into three sections: Section 2 provides a brief summary of BC Hydro's current COS methodology, including how the utility functionalizes, classifies, and allocates its revenue requirements and rate base plant in service. Section 3 summarizes the results of the jurisdictional review of COS methodologies used by other comparable utilities. Section 4 provides the findings and recommendations of SAIC's review. In addition, the following information is provided in the appendices to this report:

- Appendix A - Table showing characteristics of utilities included in the jurisdictional review.
- Appendix B – Definitions of the classification and allocation methodologies used by BC Hydro and the utilities in the jurisdictional review and descriptions of how the utilities use the methodologies.
- Appendix C – Tables showing classification and allocation COS methodologies used by the utilities in the jurisdictional review presented by type of resource, as well as target and actual R/C ratios used for proposed rate designs, as follows:

  - Table C-1 – Hydro Generation
  - Table C-2 – Non-Peaking Thermal Generation
  - Table C-3 – Peaking Thermal Generation
  - Table C-4 – Purchased Power
  - Table C-5 – Net Income from Wholesale Power Sales
  - Table C-6 – Transmission
  - Table C-7 – Distribution Substations
  - Table C-8 – Distribution Lines
  - Table C-9 – Distribution Transformers
  - Table C-10 – Distribution Services
  - Table C-11 – Distribution Meters
  - Table C-12 – DSM, Energy Efficiency, and Conservation Programs (also identifies functionalization approaches)
  - Table C-13 – Target and Actual R/C Ratios Used for Proposed Rate Designs

- Appendix D – Discussion of classification methodologies used for each type of resource from the jurisdictional review that corresponds with Tables C-1 through C-13 in Appendix C.

Section 2
REVIEW OF BC HYDRO'S COST OF SERVICE METHODOLOGY AND 2007 BCUC ORDER

Overview of the BC Hydro Cost of Service Methodology

BC Hydro uses an Excel-based cost of service model to estimate its costs to serve its major customer classes:

- Residential
- General Service under 35 kW
- Medium General Service < 150 kW
- Large General Service > 150 kW
- Irrigation
- Street Lighting
- Transmission

The model uses an embedded cost of service approach to functionalize, classify, and allocate projected test year revenue requirements[1]. Gross and net plant in service assets, excluding general plant, are also functionalized and classified for the purpose of developing factors used to classify certain portions of the revenue requirement. While the COS analysis is updated annually, the analysis that functionalizes and classifies gross and net plant has not been updated since the 2007 RDA.

The purpose of this section is to describe BC Hydro's COS methodology and the key issues raised in the 2007 BCUC decision. Definitions of the classification and allocation methodologies used by BC Hydro and the utilities in the jurisdictional review are provided in Appendix C, as well as descriptions of how they are used by the utilities.

1 Gross and net plant in service assets are functionalized and classified in a separate model from the main COS model. This analysis has not been updated since the last 2007 RDA. Some functionalization of the revenue requirement, plant, and other rate base items occurs in the revenue requirement model rather than the COS model.

Generation

In the 2007 RDA, BC Hydro proposed to classify its hydro heritage resources[2] plant in service as 50 percent demand-related and 50 percent energy-related. Regarding cost allocation, BC Hydro proposed to allocate the demand-related costs based on the 12 Coincident Peak (12 CP) method and allocate energy costs based on energy including losses, or the Energy at Generation method. In the 2007 BCUC Order, BC Hydro was required to change its classification of hydro plant to 55 percent demand-related and 45 percent energy-related and to change its use of the 12 CP method to a 4 CP method for allocation of demand-related generation costs. BC Hydro made these changes in the compliance filing.

Also in the 2007 RDA, BC Hydro proposed to classify costs for power purchases from IPPs as energy-related. As part of the 2007 BCUC order, the BCUC determined that "IPP contracts provide capacity benefits, and that the fact that the contract rates are based solely on energy is not determinative." However, the BCUC concluded that there was insufficient evidence as to the capacity benefits from these contracts. Therefore, BC Hydro's allocation was accepted as proposed, but BC Hydro was directed to prepare a study, for inclusion in its next COS or rate design filing that examines and quantifies the capacity benefits associated with IPP contracts. This analysis has been done, and BCUC expects that some allowance will be made going forward for capacity payments and other types of fixed costs associated with IPPs.

In its most recent 2012 COS Update model, BC Hydro made the changes required in the 2007 BCUC Order related to classification of its hydro heritage resources and allocation of demand-related cost. However, BC Hydro has not yet made changes to the classification approach used for IPP costs. As such, BC Hydro is using the approaches shown in Table 1 to classify and allocate other generation-related plant in service, operation and maintenance (O&M) costs, and purchased power costs.

[2] BC Hydro owns heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians.

Table 1
BC Hydro COS Methodology
Generation and Purchased Power Costs

	Classification			Allocation	
	Demand %	Energy %	Approach	Demand-Related	Energy-Related
Hydro Generation					
Plant In Service	55%	45%	Commission Ordered (1)	na	na
O&M	58%	42%	Derived from Classified Plant Costs (2)	4 CP (1)	Annual Energy at Generation
Water Rental	10%	90%	Water Rental Rates	4 CP (1)	Annual Energy at Generation
Peaking Thermal Generation					
Plant In Service	100%	0%	Demand Only	na	na
O&M	58%	42%	Derived from Classified Plant Costs (2)	4 CP (1)	Annual Energy at Generation
Fuel	0%	100%	Energy Only	na	Annual Energy at Generation
Diesel Generation - Integrated Areas					
Plant In Service	100%	0%	Demand Only	na	na
Diesel Generation - Non-Integrated Areas					
Plant In Service	0%	100%	Energy Only	na	na
O&M	0%	100%	Energy Only	na	Annual Energy at Generation
Fuel	0%	100%	Energy Only	na	Annual Energy at Generation
Purchased Power					
IPP and Long-Term Purchase Commitments (3)	0%	100%	Energy Only	na	Annual Energy at Generation
Market Purchases	0%	100%	Energy Only	na	Annual Energy at Generation

(1) As required in 2007 BCUC Order.
(2) Based on total classified gross generation plant in service.
(3) Other types of costs associated with IPPs included in BC Hydro's revenues requirement are treated differently.

The BC Hydro classification approaches shown in Table 1 for generation resources are as follows:

- **Energy Only –** BC Hydro classifies the following types of generation plant in service and O&M costs as 100 percent energy-related:
  - Fuel costs associated with thermal generation
  - Plant in service, O&M costs, and fuel costs associated with diesel generation in non-integrated areas[3]
  - Purchased power costs including market purchases and capacity and energy payments associated with purchases from IPPs
- **Demand Only –** BC Hydro classifies the following types of generation plant in service as 100 percent demand-related:
  - Plant in service associated with peaking thermal generation
  - Plant in service associated with diesel generation in integrated areas
- **Water Rental Rates** – BC Hydro allocates water rental costs based on the underlying fixed and variable rental rates.
- **Commission Ordered –** As discussed above, the 2007 BCUC Order required BC Hydro to change its classification of hydro plant in service to 55 percent demand-related and 45 percent energy-related. This classification has been used by BC Hydro since 2007.
- **Derived from Classified Plant Costs –** Using the generation plant in service classification approaches identified in Table 1, BC Hydro determined that total classified generation plant in service costs are 58 percent demand-related and 42 percent energy-related. This demand and energy split was subsequently used by BC Hydro to classify the following types of costs:
  - Hydro O&M costs
  - Peaking thermal generation O&M costs

The BC Hydro allocation approaches shown in Table 1 for generation resources are as follows:

- **4 CP –** BC Hydro uses this allocation approach for allocating the following:
  - Demand-related hydro O&M and water rental costs
  - Demand-related O&M costs associated with peaking thermal generation
- **Annual Energy at Generation –** BC Hydro uses this allocation approach for allocating the following:
  - Energy-related O&M costs for hydro, peaking thermal, and diesel generation in non-integrated areas
  - Energy-related water rental and fuel costs
  - Purchased power costs

[3] Generation in non-integrated areas is relatively expensive, and fuel costs represent a large portion of total O&M costs associated with generation in non-integrated areas. Thus, costs are classified as energy-related.

In the 2007 RDA, BC Hydro classified (1) subsidiary net income including Powerex net income, (2) revenues from electricity sales to Powerex, and (3) revenues from other surplus sales as 100 percent energy-related.

In the 2007 BCUC Order, it was determined that Powerex net income results from both capacity and energy availability on BC Hydro's system, but definitive evidence as to the split between capacity and energy was not presented. Therefore, BC Hydro was required to allocate these revenues to customer classes in the same proportions as the total generation revenue requirement. BC Hydro made these changes.

In its most recent 2012 COS Update model, BC Hydro uses the approaches shown in Table 2 to functionalize, classify, and allocate subsidiary income, including Powerex net income, and revenue from power sales, including surplus sales and sales to Powerex.

Table 2
BC Hydro COS Methodology
Powerex Net Income and Revenues from Power Sales

	Revenues from Power Sales (1)	Powerex Net Income
Functionalization		
Approach	Generation Only	Generation Only
Generation	100%	100%
Transmission	0%	0%
Classification		
Approach	Energy Only	Derived from Classified Generation Revenue Requirement (2)
% Generation Demand Related	na	31% (3)
% Generation Energy Related	100%	69% (3)
Approach	na	na
% Transmission Demand Relat	na	na
% Transmission Meter Related	na	na
Allocation		
Generation Demand Related	na	4 CP (4)
Generation Energy Related	Annual Energy at Generation	Annual Energy at Generation
Transmission Demand Related	na	na
Transmission Meter Related	na	na

(1) Revenues from sales of electricity to Powerex and other surplus sales.
(2) Based on the classified generation revenue requirement excluding subsidiary net income.
(3) Based on total classified gross transmission plant in service.
(4) As required in 2007 BCUC Order.

The BC Hydro classification and allocation approaches shown in Table 2 are as follows:

- Subsidiary Net Income (including Powerex net income)
  - Functionalization – 100 percent to generation
  - Classification – 31 percent demand-related and 69 percent energy-related based on the classified generation revenue requirement excluding subsidiary net income (i.e., Derived from Classified Generation Revenue Requirement method)
  - Allocation
    - Energy-Related – Energy at Generation method
    - Demand-related – 4 CP method
- Revenues from Power Sales (including surplus and Powerex sales revenues)
  - Functionalization – 100 percent to generation
  - Classification – 100 percent to energy (i.e., Energy Only method)
  - Energy-Related Allocation – Annual Energy at Generation method

Transmission

In the 2007 RDA, BC Hydro proposed to classify transmission plant in service as 99.99 percent demand-related and 0.01 percent meter related. For cost allocation, BC Hydro proposed to allocate the demand costs based on the 12 CP method. However, the 2007 BCUC Order required BC Hydro to change its use of the 12 CP method to a 4 CP method for demand-related transmission costs. Following the compliance order, BC Hydro made these changes.

In its most recent 2012 COS Update model, BC Hydro uses the approaches shown in Table 3 to classify and allocate transmission plant in service, O&M costs, and costs for wheeling by others.

Table 3
BC Hydro COS Methodology
Transmission Costs

	Classification			Allocation Approach	
	Demand %	Meter %	Approach	Demand-Related	Meter-Related
Transmission Assets and Lines					
Plant In Service	100%	0%	Demand Only	4 CP (1)	na
O&M	99.99%	0.01%	Derived from Classified Transmission Plant Costs (2)	4 CP (1)	Meter Replacement Costs (3)
Transmission Meters					
Plant In Service	0%	100%	Meter Only	na	Meter Replacement Costs (3)
O&M	99.99%	0.01%	Derived from Classified Transmission Plant Costs (2)	4 CP (1)	Meter Replacement Costs (3)
Domestic Transmission Related to Heritage Resources	99.99%	0.01%	Derived from Classified Transmission Plant Costs (2)	4 CP (1)	Meter Replacement Costs (3)

(1) As required in 2007 BCUC Order.
(2) Based on meter replacement costs for customers served at transmission voltages.
(3) Based on total classified gross transmission plant in service.

The BC Hydro classification approaches shown in Table 3 for transmission resources are as follows:

- **Demand Only** – BC Hydro classifies transmission assets and lines as 100 percent demand-related.
- **Meter Only –** BC Hydro classifies transmission meters as 100 percent meter related.
- **Derived from Classified Plant Costs –** Using the generation plant in service classification approaches identified in Table 3, BC Hydro determined that total classified transmission plant in service costs are 99.99 percent demand-related and 0.01 percent meter related. This demand and meter split was subsequently used by BC Hydro to classify the following types of costs:
    - O&M costs associated with transmission assets, lines, and meters
    - Domestic transmission costs for wheeling of power from heritage resources

The BC Hydro allocation approaches shown in Table 3 for transmission resources are as follows:

- **4 CP –** BC Hydro uses this allocation approach for allocating the following:
    - Demand-related O&M associated with transmission assets, lines, and meters
    - Demand-related domestic transmission costs related to heritage resources

- **Meter Replacement Costs –** BC Hydro allocates the following based on relative meter replacement costs for customers served at transmission voltages:
    - Meter-related O&M costs for transmission assets, lines and meters
    - Demand-related domestic transmission costs related to heritage resources

Distribution and Customer Care

In the 2007 RDA, BC Hydro proposed to classify its distribution plant assets as demand-related or customer-related based on several sub-functionalization categories: distribution wires system, streetlight, transformers, and revenue meters split between integrated and non-integrated service areas. A 75 percent demand-related and 25 percent customer-related split was used for plant in service related to distribution wire systems and transformers, while 100 percent of meter-related and street light-related plant in service was classified as customer-related. This resulted in classification of 71 percent of distribution plant in service as demand-related and 29 percent as customer-related. BC Hydro then proposed to use this split to classify distribution-related O&M costs. Finally, BC Hydro proposed to classify customer care costs as 100 percent customer-related.

As part of the rate case, BC Hydro submitted that if meter costs, direct-assigned street lighting costs, and customer care costs were also considered, then the “weighted average” demand/customer classification in their proposed COS analysis was 61 percent demand-related and 39 percent customer-related.

BC Hydro proposed to use variations of 1 NCP to allocate distribution demand-related O&M costs, and to use customer counts to allocate distribution customer-related costs, excluding meters and streetlight costs. BC Hydro proposed to allocate customer-related meter costs based on meter replacement costs, while assigning lighting costs directly to the streetlight class. Finally, BC Hydro proposed to use a blended allocator for customer care costs, with 90 percent based on the percentage of bills by rate class and 10 percent by the percentage of forecast revenues by rate class for customer care costs.

In the 2007 BCUC Order, BC Hydro was required to allocate the total distribution revenue requirement, from “primary to meters and including related customer care costs and directly assign street lighting”, on a 65 percent demand-related and 35 percent customer-related basis. Additionally the BCUC ordered BC Hydro to complete a minimum system study and a zero-intercept method study prior to its completion of its next COS study. In its compliance filing, BC Hydro used the 65 percent demand-related and 35 percent customer-related split and committed to complete the required studies. It completed these studies in a 2012 Distribution Study that supported the use of the 75 percent demand-related and 25 percent customer-related split classification.

In its most recent 2012 COS Update model, BC Hydro did not use these results from the 2012 Distribution Study, but rather continued the use of 65 percent demand and 35 percent customer split consistent with the 2007 Order. As such, BC Hydro is using the approaches shown in Table 4 to classify and allocate distribution and customer care O&M costs.

Table 4
BC Hydro COS Methodology
Distribution and Customer Care Costs

	Classification			Allocation Approach	
	Demand %	Customer %	Approach	Demand-Related	Customer-Related
Distribution O&M	65%	35%	Commission Ordered (1)	1 NCP	Number of Unweighted Customers
Customer Care O&M	65%	35%	Commission Ordered (1)	1 NCP	Blended Number of Bills/Revenue (2)

(1) As required in 2007 BCUC Order.
(2) Blended allocator with 90% based on the percentage of bills by rate class and 10% by the percentage of forecast revenues by rate class.

The BC Hydro allocation approaches shown in Table 4 for distribution and customer care O&M costs are as follows:

- **1 Non-Coincident Peak (NCP) –** BC Hydro allocates demand-related distribution and customer care O&M costs using this approach:
- **Number of Unweighted Customers –** BC Hydro allocates customer-related distribution O&M expenses based on the percentage of customers in each class.
- **Blended Number of Bills/Revenue** – BC Hydro uses a "blended" allocator for allocating customer care O&M costs classified as customer-related. The blended allocator is 90 percent based on the percentage of bills by rate class and 10 percent based on the percentage of forecast revenues by rate class.

DSM

In the 2007 RDA, amortization costs associated with DSM were functionalized 10 percent to transmission and 90 percent to distribution. In the 2007 BCUC Order, BC Hydro was required to functionalize all revenue requirements related to DSM as 90 percent generation-related and 10 percent transmission-related. BC Hydro was further required to allocate the portion related to generation to the customer classes in the same proportions that the total generation revenue requirement was allocated to the customer classes. BC Hydro made these changes in the compliance filing.

In its most recent 2012 COS Update model, BC Hydro uses the approach shown in Table 5 to functionalize, classify, and allocate DSM amortization costs.

Table 5
BC Hydro COS Methodology
DSM Costs

Functionalization	
Approach	Commission Ordered [1]
Generation	90% [1]
Transmission	10% [1]
Classification	
Approach	Derived from Classified Generation Plant Costs [2]
% Generation Demand Relate	58% [2]
% Generation Energy Related	42% [2]
Approach	Derived from Classified Transmission Plant Costs [3]
% Transmission Demand Rel	99.99% [3]
% Transmission Meter Relate	0.01% [3]
Allocation	
Generation Demand Related	4 CP [1]
Generation Energy Related	Annual Energy at Generation
Transmission Demand Related	4 CP [1]
Transmission Meter Related	Meter Replacement Costs [4]

(1) As required in 2007 BCUC Order.
(2) Based on total classified gross generation plant in service.
(3) Based on total classified gross transmission plant in service.
(4) Based on meter replacement costs for customers served at transmission voltages.

The BC Hydro approaches shown in Table 5 for functionalizing, classifying, and allocating DSM costs are as follows:

- Functionalization – 90 percent to generation and 10 percent to transmission
- Classification
    - Generation Classification – 58 percent to demand and 42 percent to energy based on classified gross generation plant in service as discussed above (i.e., Derived from Classified Generation Plant Costs method)
    - Transmission Classification – 99.99 percent demand-related and 0.01 percent meter-related based on classified gross transmission plant in service as discussed above (i.e., Derived from Classified Transmission Plant Costs methodology)

- Allocation
  - Demand-related – 4 CP methodology
  - Energy-Related – Energy at Generation methodology
  - Meter-Related – Based on meter replacement costs for customers served at transmission voltages (i.e., Meter Replacement Costs methodology)

Target R/C Ratios

For purposes of rate rebalancing in the 2007 RDA, BC Hydro proposed using a 90 percent to 110 percent range of reasonableness for customer class R/C ratios. As such, when a customer classes' revenue was within 90 to 110 percent of its estimated cost of service, then BC Hydro would not need to increase or decrease the revenue recovery from this customer class. In its Order, the BCUC noted the widespread practice of setting the range of reasonableness for R/C ratios at 95 percent to 105 percent in other jurisdictions and found that the "range of reasonableness of 95 percent to 105 percent is the correct range for the purpose of future rebalancing in the circumstances of BC Hydro". Furthermore, the BCUC found that the appropriate target for R/C ratios in each class is unity, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness. Finally, the BCUC directed BC Hydro to adjust its rates in equal percentage amounts over the following three-year period to achieve R/C ratios of unity for each customer class. However, the province intervened to halt any rebalancing of rates, and placed a limit on rebalancing to no more than two percentage points per year compared to the R/C ratio for that class immediately before the increase as set out in Section 58.1 of the *Utilities Commission Act*.

No significant rate rebalancing has occurred since that time. Along with other changes in costs and the changes in the cost of service methodology required by the BCUC Order from the 2007 RDA as discussed above, the R/C ratios from BC Hydro's 2012 COS study ranged from 87 percent to 126 percent.

Section 3
REVIEW OF COST OF SERVICE METHODOLOGIES FOR SELECTED UTILITIES

Approach and Selection Method

To understand better how other comparable utilities have addressed the COS methodological issues identified in Section 2 of this report, SAIC in conjunction with BC Hydro staff conducted a review of COS studies and filings made by similar North American electric utilities. These utilities were selected based on the following criteria:

- Significant portion of generation derived from hydro resources, preferably utility owned but also as purchased power
- Primarily winter peaking system
- Preference for utilizing an embedded COS methodology, but not excluding utilities utilizing a marginal COS methodology
- Providing vertically integrated services, including generation, transmission, and distribution of power
- Relatively large size in terms of revenue (greater than $500 million revenues) and customers served (greater than 100,000 customers)

In reviewing a number of listings of North American electric utilities, it was determined that only BC Hydro met all of these criteria. Consequently, the selection process was modified to include those utilities that best met most of these criteria. Rate case filings or studies by nine utilities in ten separate jurisdictions were selected to include in the survey as follows:

- Avista Corporation–Idaho (filing made before the Idaho Public Utilities Commission)
- Avista Corporation–Washington (filing made before the Washington Utilities and Transportation Commission)
- Bonneville Power Administration (BPA)
- Hydro-Québec Distribution
- Idaho Power Company (Idaho Power) (filing made before the Idaho Public Utilities Commission)
- Manitoba Hydro

- Newfoundland Power Inc.
- Portland General Electric Company (Portland General)
- Puget Sound Energy
- Seattle City Light

For ease of reference, Avista Corporation–Idaho and Avista Corporation–Washington will be referred to as separate utilities throughout this report.

Characteristics of Utilities in Jurisdictional Review

Appendix A includes a table showing key characteristics of the utilities included in the jurisdictional review as well as each utility's rate filings or studies used for the review. The utilities included in the jurisdictional review are vertically integrated utilities that supply the majority of their own power needs and primarily serve retail customers with the following exceptions:

- BPA is a federal nonprofit agency based in the Pacific Northwest. BPA markets wholesale power from federal hydro projects in the Columbia River Basin, one nonfederal nuclear plant, and several other small nonfederal power plants. BPA's power services customers primarily include cooperatives, municipalities, and public utility districts, but they also serve other federal agencies, investor-owned utilities, direct service industries, a port district, and tribal utilities. They do not have any distribution assets.
- Since 2000, Hydro-Québec has been divided into three major divisions (Hydro-Québec Production, Hydro-Québec TransÉnergie, and Hydro-Québec Distribution). Hydro-Québec Production supplies Hydro-Québec Distribution with power from heritage resources, which are dedicated supply resources reserved for Quebec markets up to a maximum of specified maximum amount per year. To meet demand beyond that volume, Hydro-Québec Distribution must enter into supply contracts by conducting calls for tenders among interested power suppliers.
- Newfoundland Power purchases approximately 90 percent of its electricity requirements from Newfoundland and Labrador Hydro, and it generates the balance from its own smaller hydro stations.

Additional characteristics of the utilities included in the jurisdictional review are as follows:

- A significant portion of all the utilities' power supply needs are provided by hydro resources. The percentages of their power supply requirements that come from hydro resources range from 42 percent for Portland General Electric to 98 percent for Hydro-Québec, as compared to 89 percent for BC Hydro.
- With the exception of Idaho Power, the utilities are all winter peaking like BC Hydro.

- Portland General and Seattle City Light use primarily marginal COS methodologies, while the other utilities primarily use embedded COS methodologies similar to BC Hydro.
- Five of the utilities are investor owned, while the others are publically owned like BC Hydro. The investor-owned utilities include Avista, Idaho Power, Newfoundland Power, Portland General Electric, and Puget Sound Energy.
- Without including Newfoundland Power that purchases 90 percent of its electricity requirements, the percentages of the utilities' power supplies that they purchase, rather than generate themselves, range from approximately 3 percent for Manitoba Hydro to 58 percent for Portland General Electric. This compares to 40 percent for BC Hydro.
- The utilities' electric sales revenues range from about $600 million for Newfoundland Power to $12.1 billion for Hydro-Québec, and the number of electric retail customers ranges from approximately 240,000 for Newfoundland Power to 4.1 million for Hydro-Québec. In comparison, BC Hydro has approximate $4.4 billion per year in electric sales revenues and 1.9 million customers.

The primary sources of information used in the jurisdictional review were the most recent case rate filings or COS and rate design studies prepared by each of the utilities.[4] Review of this information focused on COS methodology issues, including classification and allocation methods, R/C ratio targets, and related issues identified previously in this report. The focus of the review was to identify the COS methodologies used, but the bases for the methods chosen by the utilities were noted when readily identifiable. The rate filings and studies identified in Appendix A were reviewed between February and May 2013, and results were tabulated in June 2013.

Key Findings

The following categories of key findings from the jurisdictional review are summarized below:

- Generation COS Methodologies
- Transmission COS Methodologies
- Distribution COS Methodologies
- DSM, Energy Efficiency, and Energy Conservation COS Methodologies
- Target and Actual R/C Ratios Used for Proposed Rate Designs

Tables showing the detailed results of the jurisdictional review are provided in Appendix B. Definitions of the classification and allocation methodologies used by utilities in the jurisdictional review, as well as descriptions of how they are used by the

[4] Hydro-Québec Distribution staff provided oral and written information.

utilities, are provided in Appendix C. A discussion of the detailed results on classification methodologies is provided in Appendix D.

Generation COS Methodologies

The results of the jurisdictional review of generation COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The types of generation COS methodologies used by the utilities included in the jurisdictional review by type of resource are presented below.

The approaches used to classify and allocate hydro plant in service and associated O&M costs, including water costs, are summarized in Table 6. More detailed information is provided in Table C-1 of Appendix C and the written descriptions of the hydro generation classification and allocation methodologies in Appendices C and D.

Table 6
Results of Jurisdictional Review
Hydro Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Water Costs (2)	Water Costs (2)	
Classification Methodologies				
Energy Only	1	2	3	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
Generation Marginal Costs - Energy Only	na	1	1	0%
Hydro Peak Credit	1	1	na	42%
System Load Factor	3	2	3	34%-46%
System Load Factor/Energy Only (3)	na	1	na	44%
Thermal Peak Credit	1	1	1	19%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
4 CP	na	1	1	na
12 CP	3	3	2	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	4	4	4	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	2	4	4	na

(1) Four utilities do not classify and allocate hydro generation plant in service costs because it is either not required for their COS approach or they do not have any hydro assets.
(2) One utility does not classify and allocate hydro O&M costs or water costs because they do not have any of their own hydro assets.
(3) One utility uses the System Load Factor method to classify all hydro O&M costs, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate non-peaking thermal plant in service and associated O&M costs, including fuel costs, are summarized in Table 7. More detailed information is provided in Table C-2 of Appendix C and the written descriptions of the non-peaking thermal generation classification and allocation methodologies in Appendices C and D.

Table 7
Results of Jurisdictional Review
Non-Peaking Thermal Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Fuel Costs (2)	Fuel Costs (2)	
Classification Methodologies				
Demand Only	1	1	1	100%
Energy Only	1	2	4	0%
Generation Marginal Costs - Energy Only	na	1	1	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
System Load Factor	2	1	1	34%-46%
System Load Factor/Energy Only (3)	na	1	na	28%
Thermal Peak Credit	2	2	1	19%-42%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
4 CP	na	1	1	na
12 CP	3	3	1	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	3	3	3	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	2	4	4	na

(1) Four utilities do not classify and allocate non-peaking thermal generation plant in service costs because it is either not required for their COS approach or they do not have any non-peaking thermal generation assets.

(2) One utility does not classify and allocate non-peaking thermal generation O&M costs or fuel costs because they do not have any of their own non-peaking thermal generation assets.

(3) One utility uses the System Load Factor method to classify all non-peaking thermal generation O&M costs, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate peaking thermal plant in service and associated O&M costs, including fuel costs, are summarized in Table 8. More detailed information is provided in Table C-3 of Appendix C and the written descriptions of the peaking thermal generation classification and allocation methodologies in Appendices C and D.

Table 8
Results of Jurisdictional Review
Peaking Thermal Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Fuel Costs (2)	Fuel Costs (2)	
Classification Methodologies				
Demand Only	3	2	1	100%
Demand Only/Energy Only (3)	na	1	na	85%
Energy Only	1	2	4	0%
Generation Marginal Costs - Energy Only	na	1	1	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
System Load Factor	1	1	1	34%
Thermal Peak Credit	1	1	1	19%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
3 CP	1	1	na	na
4 CP	na	1	1	na
12 CP	2	2	1	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	2	2	3	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	1	4	4	na

(1) Four utilities do not classify and allocate peaking thermal generation plant in service costs because it is either not required for their COS approach or they do not have any peaking thermal generation assets.

(2) One utility does not classify and allocate peaking thermal generation O&M costs or fuel costs because they do not have any of their own peaking thermal generation assets.

(3) One utility classifies all peaking thermal O&M costs using the Demand Only method, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate purchased power costs are summarized in Table 9. More detailed information is provided in Table C-4 of Appendix C and the written descriptions of the purchased power classification and allocation methodologies in Appendices C and D.

Table 9
Results of Jurisdictional Review
Purchased Power Cost Classification and Allocation Methodologies

	Number of Utilities	% Classified as Demand-Related
Classification Methodologies		
Derived from Classified Plant Costs	1	48%
Energy Only	3 (1)	0%
Generation Marginal Costs - Energy Only	1	0%
Generation Marginal Costs - Demand & Energy	1	35%
Supplier COS Results	1	30%
System Load Factor	3 (1)	34%-44%
Thermal Peak Credit	1	19%
Demand-Related Allocation Methodologies		
1 CP	1	na
4 CP	1	na
12 CP	3	na
Ave of Loads During Select Peak Periods	1	na
Relationship of Class to System Load Factors	1	na
Energy-Related Allocation Methodologies		
Annual Energy at Generation	5	na
Direct Assignment/Annual Energy at Generation (aMW)	1	na
Weighted Annual Energy at Generation	5	na

(1) One utility classifies purchased power costs from their supplier's heritage resources using the System Load Factor method. Other purchased power costs are classified using the Energy Only method.

The approaches used to classify and allocate net income from wholesale power sales revenues are summarized in Table 10. More detailed information is provided in Table C-5 of Appendix C and the written descriptions of the net income from wholesale power sales allocation methodologies in Appendices C and D.

Table 10
Results of Jurisdictional Review
Net Income from Wholesale Power Sales Cost
Classification and Allocation Methodologies

	Number of Programs (1)	% Classified as Demand-Related
Overall Approach		
Recognizes Wholesale Power Sales as Separate Class in COS	2	na
Allocates Wholesale Power Sales Revenues to Other Customer Classes	4	na
Classification Methodologies		
Derived from Classified Plant Costs	1	48%
Energy Only	1	0%
Generation Maginal Costs - Revenue Only (2)	1	0%
System Load Factor	1	34%
Demand-Related Allocation Methodologies		
12 CP	2	na
Energy-Related Allocation Methodologies		
Annual Energy at Generation/aMW	3	na
Weighted Annual Energy at Generation	1	na
Revenue-Related Allocation Methodologies		
Derived from Marginal Allocated Revenue Requirements (2)	1	na

(1) Four utilities either did not separately show how net income from wholesale power sales were handled in their COS study or they do not have any net income from wholesale power sales.
(2) One utility classifies net income from wholesale power sales as 100 percent revenue-related and then allocates the revenues to customer classes using the Derived from Marginal Allocated Revenue Requirements method.

Observations on Classification of Generation Costs

The following are overall observations regarding the classification methodologies used by the utilities in the jurisdictional review to classify generation costs:

- There is not one single predominant method used to classify generation costs, even by type of generation resource.
- Six of the utilities use the same approach to classify all costs for hydro, non-peaking thermal, and peaking thermal generation, well as purchased power costs. The majority of these utilities use Energy Only or Marginal Cost classification methods.

- The other utilities use different approaches based on the type of generation, especially for peaking thermal generation costs as compared to hydro and non-peaking thermal generation costs.
- The classification methodologies used for peaking thermal generation costs generally classify a higher percentage of costs as demand-related as compared to those methodologies used for other types of generation costs.
- Two utilities use different classification approaches for fuel and water costs as compared to other types of generation O&M costs. These utilities classify fuel and/or water costs as energy-related while other O&M costs are classified as both demand-related and energy-related.
- Three of the utilities either currently use a Peak Credit method to classify generation costs or recently switched from using a Peak Credit method. One utility currently using a Peak Credit methodology indicated that they would prefer to use a System Load Factor approach for classification, but they continued to use the Peak Credit approach in their rate filing to potentially limit the number of issues in their rate case. The utility that recently switched from using a Peak Credit method went to a System Load Factor method, and indicated it changed from using a Peak Credit method because the Peak Credit method is complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines.

Hydro and Non-Peaking Thermal Generation

Observations specifically regarding the classification of hydro and non-peaking thermal generation costs by the utilities in the jurisdictional review are as follows:

- Six of the utilities use an approach that classifies some or all of their hydro generation plant in service costs and O&M costs as both demand-related and energy-related. Five of the utilities use an approach that classifies some or all of their non-peaking thermal generation plant in service costs and O&M costs as both demand- and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 46 percent as shown in Tables 6 and 7 as well as Tables C-1 and C-2 in Appendix C.
- Hydro and non-peaking thermal generation plant in service costs and O&M costs are most commonly classified using Energy Only, System Load Factor, and Hydro/Thermal Peak Credit methods.
- Of the three utilities using the Energy Only methodology, one is required to use it by law and they subsequently allocate hydro and non-peaking thermal costs using a combination of direct assignments and the Annual Energy at Generation methodology, or average load. The other two use energy allocation factors weighted for marginal costs (i.e., Weighted Annual Energy Generation methods) to allocate hydro and non-peaking thermal generation costs to customer classes, and one of these two utilities only classifies certain

O&M costs using the Energy Only method with the balance of O&M costs being classified using the System Load Factor method.

Peaking Thermal Generation

Observations specifically regarding the classification of peaking thermal generation costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities use an approach that classifies some or all of their peaking thermal generation plant in service costs and O&M costs as both demand-related and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 85 percent as shown in Table 8 and Table C-3 in Appendix C.
- Peaking thermal generation plant in service costs and O&M costs are most commonly classified using Demand Only and Energy Only methods.
- Of the three utilities using the Energy Only methodology, one is required to use it by law and they subsequently allocate peaking thermal costs using a combination of direct assignments and the Annual Energy at Generation method, or average load. The other two use energy allocation factors weighted for marginal costs (i.e., Weighted Annual Energy Generation methodology) to allocate peaking thermal costs to customer classes, and one of these two utilities only classifies certain O&M costs using the Energy Only method with the balance of O&M costs being classified using the Demand Only method.

Purchased Power

Observations specifically regarding the classification of purchased power costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities use an approach that classifies some or all of their purchased power costs as both demand-related and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 48 percent as shown in Table 9 and Table C-4 in Appendix C.
- Purchased power costs are most commonly classified using the Energy Only or System Load Factor methods.
- Seven of the utilities use the same approaches for allocating purchased power costs as other types of generation costs. The other utilities use an allocator this is derived from total classified generation plant in service costs or their power supplier COS results.

Net Income from Wholesale Power Sales

With regard to the functionalization and classification of net income from wholesale power sales, two of the utilities recognize customers purchasing wholesale power as a separate customer class. The other utilities generally classify and allocate the net revenues consistent with the aggregate classification and allocation results for other generation resources. The percentages of net income classified as demand-related by these utilities range from 34 percent to 48 percent as shown in Table 10 and Table C-5 in Appendix C.

Observations on Allocation of Generation Costs

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate demand-related generation costs are as follows:

- There is not one single predominant method used to allocate demand-related generation costs. However, the most common approach is the 12 CP method. This approach generally acknowledges that the majority of the utilities in the jurisdictional review experience their highest peaks in the winter, but they also experience high summer peaks.
- With one exception, each utility uses the same type of demand-related allocator for all their types of generation resources. The one exception uses 12 CP for all demand-related generation costs except for peaking thermal demand-related costs. These are allocated using a 3 CP approach.

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate energy-related generation costs are as follows:

- There is not one single predominant method used to allocate energy-related generation costs. Both the Annual Energy at Generation and Weighted Annual Energy at Generation are used.
- Weighted Annual Energy at Generation is used primarily by utilities using either the Energy Only or Marginal Costs classification approaches.

Transmission COS Methodologies

The results of the jurisdictional review of transmission COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The approaches used to classify and allocate transmission plant in service and associated O&M costs are shown in Table 11. More detailed information is provided in Table C-8 of Appendix C and the written descriptions of the transmission classification and allocation methodologies in Appendices C and D.

Table 11
Results of Jurisdictional Review
Transmission Costs Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs	Demand-Related
Classification Methodologies			
Demand Only	4	6 (2)	100%
Energy Only	na	1	0%
System Load Factor	1	1	34%
Thermal Peak Credit	1	1	19%
Transmission Division's Classified Rev Reqmt	na	1 (2)	43%
Transmission Marginal Costs - Demand Only	na	1 (3)	100%
Transmission Marginal Costs - Energy Only	na	1 (3)	0%
Demand-Related Allocation Methodologies			
1 CP	1	2 (2)	na
12 CP	2	2	na
1 NCP	1 (4)	2 (2)(4)	na
Weighted 12 CP	1	1	na
Ave of Loads During Select Peak Periods	2 (4)	3 (3)(4)	na
Energy-Related Allocation Methodologies			na
Annual Energy at Generation/aMW	2	5 (3)	na
Weighted Annual Energy at Generation	na	na	na

(1) Four utilities do not classify and allocate transmission plant in service costs because it is either not required for their COS approach or they do not have transmission assets.
(2) One utility classifies the costs charged to it by another division of the utility for generation-related transmission and interconnections with neighboring systems based on the transmission division's load factor. Network transmission costs, and costs related to customer connections, are classified as 100 percent demand-related. The demand-related costs for the generation-related transmission, interconnections with neighboring systems and network transmission costs are allocated using the 1 CP method. The costs related to customer connections are allocated using the 1 NCP method.
(3) One utility treats marginal transmission costs as demand-related and costs for wheeling by others as energy-related. Demand-related costs are allocated based on averages of peak loads during 48 costing period. Energy-related costs are allocated based on annual energy at generation.
(4) One utility sub-functionalizes their system into transmission and subtransmission. Transmission costs are allocated based on the average loads during the highest 50 peak hours in the summer and winter seasons. Subtransmission costs are allocated using the 1 NCP method.

Observations

The following are observations regarding the methodologies used by the utilities in the jurisdictional review to classify and allocate transmission costs:

- In the jurisdictional review, the Demand Only method is the most common classification method for transmission costs. However, several other methods are also used. The types of allocation factors used for demand-related transmission costs are spread fairly evenly between the 1CP, 12 CP, 1 NCP, and Average of Loads During Select Peak Periods methods.

- Three of the utilities use an approach that classifies some or all of their transmission plant in service costs and associated O&M costs as both demand-related and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 43 percent as shown in Table 11 and Table C-6 in Appendix C.

- Six of the utilities in the jurisdictional review use the same general approach to classify transmission resources as generation resources. Five utilities use the same general approach to allocate transmission demand-related costs and generation demand-related costs. Four utilities use the same approach to allocate transmission energy-related costs and generation energy-related costs.
- Three of the utilities sub-functionalize their transmission costs to separate out transmission by type of use such as (1) generation-related or long-distance related versus in-area or network-related, (2) backbone power transmission versus radial transmission/subtransmission being used primarily as high voltage distribution, etc.

Distribution COS Methodologies

The results of the jurisdictional review of distribution COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The types of distribution COS methodologies used by the utilities included in the jurisdictional review by type of resource are presented below.

The approaches used to classify and allocate distribution substation plant in service and associated O&M costs are summarized in Table 12. More detailed information is provided in Table C-9 of Appendix C and the written descriptions of the distribution substation classification and allocation methodologies in Appendices C and D.

Table 12
Results of Jurisdictional Review
Distribution Substation Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Demand Only	7	7	100%
Dist Substation Marginal Costs - Demand Only	na	2	100%
Demand-Related Allocation Methodologies			
1 NCP	3	4	na
12 NCP	3	3	na
Ave of Loads During Select Peak Periods	na	1	na
Substation 12 NCPs	1	1	na

(1) Three utilities do not classify and allocate distribution substation plant in service costs because it is either not required for their COS approach or they do not have distribution substation assets.
(2) One utility does not classify and allocate distribution substation O&M costs because it does not have distribution substation assets.

The approaches used to classify and allocate distribution lines plant in service and associated O&M costs are summarized in Table 13. More detailed information is provided in Table C-10 of Appendix C and the written descriptions of the distribution wires classification and allocation methodologies in Appendices C and D.

Table 13
Results of Jurisdictional Review
Distribution Lines Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Computation Method	1	1	64%
Demand Only	3	3	100%
Distribution Lines Marginal Costs - Demand Only	na	2	100%
Historic Study	1	1	60%
Minimum System Study	2	2	64%-79%
Demand-Related Allocation Methodologies			
1 NCP	3	4	na
12 NCP	3	3	na
Ave of Loads During Select Peak Periods	na	1	na
Feeder 12 NCPs and Miles	1	1	na
Customer-Related Allocation Methodologies			
Number of Unweighted Customers	4	4	na

(1) Three utilities do not classify and allocate distribution line costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution line costs because it does not have any distribution assets.

The approaches used to classify and allocate distribution transformer plant in service and associated O&M costs are summarized in Table 14. More detailed information is provided in Table C-11 of Appendix C and the written descriptions of the distribution wires classification and allocation methodologies in Appendices C and D.

Table 14
Results of Jurisdictional Review
Distribution Transformer Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Computation Method	1	1	64%
Customer Only	2	2	0%
Demand Only	3	3	100%
Distribution Transformer Marginal Costs - Customer Only	na	1	0%
Distribution Transformer Marginal Costs - Demand Only	na	1	100%
Zero Intercept Analysis	1	1	73%
Demand-Related Allocation Methodologies			
1 NCP	3	3	na
12 NCP	2	2	na
Connected Load	na	1	na
Customer-Related Allocation Methodologies			
Direct to Customer Classes	1	1	na
Number of Unweighted Customers	1	1	na
Number of Weighted Customers	2	3	na

(1) Three utilities do not classify and allocate distribution transformer plant in service costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution transformer O&M costs because it does not have any distribution assets.

The approaches used to classify and allocate distribution services plant in service are summarized in Table 15. More detailed information is provided in Table C-12 of Appendix C and the written description of the distribution services plant classification and allocation methodologies in Appendices C and D.

Table 15
Results of Jurisdictional Review
Distribution Services Cost Classification and Allocation Methodologies

	Number of Utilities (1)	% Classified as Demand-Related
Classification Methodologies		
Customer Only	7	0%
Distribution Services Marginal Costs - Customer Only	1	0%
Distribution Services Marginal Costs - Demand Only	1	100%
Demand-Related Allocation Methodologies		
Ave of Loads During Select Peak Periods	1	na
Customer-Related Allocation Methodologies		
Direct to Customer Classes/No. of Services	1	na
Number of Unweighted Customers	3	na
Number of Weighted Customers	4	na

(1) One utility does not classify and allocate distribution service plant in service costs because they do not have distribution assets.

The approaches used to classify and allocate distribution meters plant in service and associated O&M costs are summarized in Table 16. More detailed information is provided in Table C-13 of Appendix C and the written description of the distribution meter classification and allocation methodologies in Appendix D.

Table 16
Results of Jurisdictional Review
Distribution Meter Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Customer Only	7	7	0%
Distribution Meter Marginal Costs - Customer Only	na	2	0%
Customer-Related Allocation Methodologies			
Book Value	1	1	na
Number of Weighted Customers	6	7	na
Number of Weighted Meters	na	1	na

(1) Three utilities do not classify and allocate distribution meter plant in service costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution meter O&M costs because it does not have any distribution assets.

Observations on Classification of Distribution Costs

The following are overall observations regarding the classification methodologies used by the utilities in the jurisdictional review to classify distribution costs:

- All the utilities classify distribution substation costs as 100 percent demand-related and distribution services and meter costs as 100 percent customer-related.
- Four utilities classify costs for distribution lines as both demand-related and energy-related, while only two utilities classify costs for transformers as both demand-related and customer-related. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related ranged from 60 percent to 79 percent. The other utilities classified these types of costs as either 100 percent demand-related or 100 percent customer-related.
- Three utilities use the same approach for classifying costs associated with distribution lines as for classifying distribution transformer costs. The others use different approaches.
- Seven of the utilities use the same demand-related allocator to allocate demand-related costs for distribution substations, lines, and transformers.
- The type of customer-related allocation factors used by the utilities generally varied by type of distribution costs. Most commonly, the methods used are either Number of Weighted Customers or Number of Unweighted Customers.

For the Number of Weighted Customer method, the type of weightings vary by type of distribution costs.

Distribution Substations

Observations specifically regarding classification of distribution substation costs by the utilities in the jurisdictional review are as follows:

- As stated above, all of the utilities with distribution assets classified associated plant in service and O&M costs as 100 percent demand-related.
- Seven of the utilities used the Demand Only method while the other two utilities, as part of their overall marginal cost methodology, treat their distribution substation marginal costs as 100 percent demand-related.

Distribution Lines

Observations specifically regarding classification of costs for lines by the utilities in the jurisdictional review are as follows:

- Five of the utilities in the jurisdictional survey classify costs for distribution lines as 100 percent demand-related. Of these utilities, three use the Demand Only method while the other two utilities, as part of their overall marginal cost methodology, treat their marginal costs for lines as 100 percent demand-related.
- None of the utilities classify 100 percent of costs for distribution lines as 100 percent customer-related.
- Four of the utilities use classification approaches that classify costs for distribution lines as both demand-related and customer-related. Some of the studies or approaches used to classify these costs appeared to be somewhat dated. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related ranged from 60 percent to 79 percent as shown in Table 13 and Table C-10 of Appendix C.

Distribution Transformers

Observations specifically regarding classification of transformer costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities in the jurisdictional survey classify transformer costs as 100 percent demand-related. Of these utilities, three use the Demand Only method while the other utility, as part of their overall marginal cost methodology, treats their distribution transformer marginal costs as 100 percent demand-related.
- Three of the utilities in the jurisdictional survey classify transformer costs as 100 percent customer-related. Of these utilities, two use the Customer Only method while the other utility, as part of their overall marginal cost methodology, treats their distribution transformer marginal costs as 100 percent customer-related.

- Two of the utilities use classification approaches that classify transformer costs both demand-related and customer-related. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related range from 64 percent to 73 percent as shown in Table 14 and Table C-11 of Appendix C. The other utilities classify these types of costs as either 100 percent demand-related or 100 percent customer-related.

Distribution Services and Meters

All of the utilities in the jurisdictional review classify distribution services and meter costs as 100 percent customer-related. They all use the Customer Only method except the two utilities that, as part of their overall marginal cost methodology, treat their marginal costs for distribution services, and/or meters, as 100 percent customer-related.

Observations on Allocation of Distribution Costs

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate demand-related and customer-related distribution costs are as follows:

- There is not one single predominant method used to allocate demand-related distribution costs. Both the 1 NCP and 12 NCP methods are common.
- Also, there is not one single predominant method used to allocate customer-related distribution costs. The Number of Unweighted Customers method and the Number of Weighted Customers method are most common, but it should be noted that the type of weightings used by those utilities that employ the Number of Weighted Customers method vary significantly between utilities and types of distribution costs.
- As discussed previously, the majority of the utilities use the same demand-related allocator to allocate demand-related costs for distribution substations, lines, and transformers.
- Some of the utilities use rather sophisticated distribution costs allocation methodologies that require detailed accounting data or feeder load data to either directly assign or allocate certain distribution costs. Not all facilities have this type of data available.

COS Methodologies for DSM, Energy Efficiency, and Conservation Programs

The results of the jurisdictional review of COS methodologies for DSM, energy efficiency, and conservation programs, and observations about those results, are presented below.

Results of Jurisdictional Review

The approaches used to functionalize, classify, and allocate DSM, energy efficiency, and conservation program costs by the utilities in the jurisdictional review are summarized in Table 17. More detailed information is provided in Table C-12 of Appendix C and the written description of the DSM, energy efficiency, and conservation program classification and allocation methodologies in Appendices C and D.

Table 17
Results of Jurisdictional Review
DSM, Energy Efficiency, and Conservation Program Cost
Classification and Allocation Methodologies

	Number of Programs (1)	% Functionized as Gen/Trans/Dist Related	% Classified as Demand-Related
Functionalization Methodologies			
Generation Only	7	100%	na
Derived from Other Functionalized O&M Costs	2	Gen 13%-95% / Trans 2%-10% / Dist 4%-59%	na
Supply Cost Savings	1	Gen 97% / Trans 3%	na
Classification Methodologies			
Demand Only	3	na	100%
Derived from Classified Plant Costs	1	na	48%
Derived from Other Classified O&M Costs	1	na	49%
Energy Only	1	na	0%
Generation Marginal Costs - Energy Only	1	na	0%
Supply Cost Savings	1	na	5%
System Load Factor	1	na	46%
Thermal Peak Credit	1	na	19%
Demand-Related Allocation Methodologies			
1 CP	2	na	na
3 CP	1	na	na
12 CP	2	na	na
Derived from Other Demand-Related Allocated C	2	na	na
Ave of Loads During Select Peak Periods	1	na	na
Energy-Related Allocation Methodologies			
Derived from Other Energy-Related Allocated O&	1	na	na
Annual Energy at Generation/aMW	4	na	na
Weighted Annual Energy at Generation	2	na	na

(1) Two of the utilities separately identified costs for multiple types of programs. Costs for DSM, energy efficiency, or conservation programs were not separately identified in three of the utilities' COS analyses.

Observations

Observations regarding the functionalization and classification of DSM, energy efficiency, and energy conservation costs by the utilities in the jurisdictional review are as follows:

- The majority of the utilities functionalize 100 percent of these costs to generation. The other utilities allocate the costs to multiple functions using functionalization factors derived from other types of functionalized costs or savings such as administrative and general expenses, supply costs savings, and total functionalized O&M costs. For those utilities allocating costs to multiple functions, the ranges of amounts allocated to each function are as follows:
    - Generation - 13 percent to 95 percent.
    - Transmission - 2 percent to 10 percent.
    - Distribution - 0 percent to 59 percent.
- For the majority of the utilities, the approaches used to classify some or all of their DSM, energy efficiency, and energy conservation costs differ from the approaches used for other types of generation resources.

Target R/C Ratios

The results of the jurisdictional review regarding approaches for establishing target R/C ratios for rate design are presented below.

Results of Jurisdictional Review

The utilities' approaches for establishing the R/C ratios for their proposed rate design are summarized in Table 18. More detailed information is provided in Table C-13 of Appendix C and the written description of the distribution meter classification and allocation methodologies in Appendices C and D.

Table 18
Results of Jurisdictional Review
Approaches for Establishing R/C Ratios for Proposed Rate Design

		Based on Existing Rates		Based on Proposed Rates
Approaches for Establishing R/C Ratios for Proposed Rate Design	Target R/C Ratios	Total System R/C Ratio	Range of Class R/C Ratios	Range of Class R/C Ratios
Across-the-Board Increases	na	92%	81% - 119%	89% - 130%
Across the Board Increases w/ Specified Residential R/C Ratio	na	na	na	83% - 134%
Caps on Rate Increases	100%	92%	41% - 106%	48 % - 104%
COS Results as a "Guide"	na	96%	86% - 107%	90% - 111%
Dictated by Law	100%	na	na	100%
Dictated by City Council Resolutions	100%	96%	79% - 103%	100%
Limits on Rate Increases and Decreases	100%	92%	57% - 216%	66% - 216%
Mutiple Guidelines	95% - 105%	92%	81% - 98%	93% - 105%
Target Range of R/C Ratios	90% - 110%	100%	95% - 113%	96% - 110%
Target Range of R/C Ratios /Across-the-Board Rate Changes	95% - 105%	100%	89% - 108%	94% - 114%

The information in Table 18 shows the following:

- **Across-the-Board Increases –** Two utilities primarily used across-the-board increases in their rate design approach, with provincial law requiring one utility to keep the residential R/C ratio at 0.83. This resulted in class R/C ratios for proposed rates in the range of 89 percent to 130 percent and 83 percent to 134 percent for these two utilities, respectively.

- **Caps on Rate Increases –** One of the utilities limited rate increases to a maximum increase of 17 percent per class, and the resulting range of class R/C ratios for proposed rates was 48 percent to 104 percent.

- **COS Results as a "Guide" –** One of the utilities indicated they use the COS results as a "guide" for rate design. The range of R/C ratios resulting from their proposed rates was 90 percent to 111 percent.

- **Dictated by Law/City Resolutions –** Two of the utilities identified target R/C ratios of 100 percent in their rate design objectives and proposed rates generally brought customer classes to R/C ratios of 100 percent. The rate design approaches used by these two utilities are largely dictated by law or city council resolutions.

- **Limits on Rate Increases and Decreases –** One utility uses the following guidelines to move their customer classes toward R/C ratios of 100 percent: (1) no decreases for any rate class and (2) a cap of 1.5 times the system average rate increase for any class. The range of R/C ratios resulting from their proposed rates was 66 percent to 216 percent.

- **Multiple Guidelines –** One of the utilities reported that a range of target R/C ratios for rate design equal to 95 percent to 105 percent was among their rate design objectives. With some additional guidelines that limited increases and decreases, the utility's range of class R/C ratios resulting from their proposed rate designs was 93 percent to 105 percent.

- **Target Range of R/C Ratios –** One of the utilities reported a range of target R/C ratios for rate design equal to 90 percent to 110 percent, and their proposed rates resulted in all class R/C ratios being within the target range. The range of R/C ratios resulting from the proposed rates was 96 percent to 110 percent.
- **Target Range of R/C Ratios/Across-the-Board Rate Increases –** One of the utilities reported that a range of 95 percent to 105 percent for targeted class R/C ratios was among their rate design objectives, but then proposed across-the-board rate increases that resulted in class R/C ratios for proposed rates in the range of 94 percent to 114 percent.

Observations

In general, the utilities in the jurisdictional review all indicated they advocate movement towards cost based rates in their rate design proposals, but other objectives such as rate stability and minimizing customer impacts were also of importance. Only one utility proposed rates that brought all their customer classes with their target range of R/C ratios. As shown in Table 18, the rates proposed by several of the utilities result in class R/C ratios outside a range of 90 percent to 110 percent. Most of the utilities have multiple guidelines or rate design objectives that are used for rate rebalancing.

The overall COS approach used by BC Hydro in the 2007 RDA, as well as the current COS approach that incorporates the changes required by the 2007 BCUC order, are generally consistent with standard embedded cost of service methodologies used by other electric utilities in North America with one exception. Customer care costs are typically classified as 100 percent customer-related, but customer care costs are currently classified as 65 percent demand-related and 35 percent customer-related in the BC Hydro COS model as a result of the outcome from their 2007 RDA.

The results of the jurisdictional review showed that a wide variety of approaches are used to classify and allocate generation, transmission, and distribution costs. In addition, a variety of approaches are used for rate rebalancing. Based on the results of the review of COS methods identified in the jurisdictional review discussed in Section 3 as well as the prior experience of the SAIC review team, a number of observations were made and recommendations developed for BC Hydro staff to consider modifying when preparing its COS analysis for its next COS study. These observations and recommendations are summarized in the following paragraphs.[5] Unless specifically addressed in this section, the implication is that the COS methodologies currently employed by BC Hydro are generally acceptable and no other changes to the COS methodology are recommended.

Generation COS Methodologies

Based on the results of the jurisdictional review and our review of the BC Hydro system and BC Hydro's COS methodology, we believe it is appropriate for BC Hydro to evaluate the feasibility of using either (1) a system load factor approach (i.e., ratio of system average demand to system peak demand) to classify all hydro plant in service and O&M costs, except water rental costs; or (2) a plant capacity factor approach (i.e., ratio of average plant load to nameplate plant capacity) that sub-functionalizes hydro plant in service and O&M costs by individual plant or groups of plants and then uses the corresponding plant capacity factors to classify hydro plant and O&M costs, excluding water costs.

We also believe that it would be appropriate for BC Hydro to classify all peaking thermal generation plant in service and associated O&M costs excluding fuel costs (to the extent those costs can be separately identified) as demand-related rather than the current approach of classifying peaking thermal generation plant in service costs as demand-related and classifying peaking thermal generation O&M costs, as well as other types of generation O&M costs excluding costs for fuel and water rentals, as both demand-related and energy-related.

[5] In addition, we provided to BC Hydro certain suggestions on several COS methodology modifications beyond those discussed in this section, but the impact of making these changes would be minimal.

When considering the type of allocation factors to use for generation costs, it is important to consider these in context with the type of classification factors used. The use of a system load factor or plant capacity approach for classifying hydro costs inherently acknowledges that the hydro resources are used for both baseload and peaking purposes with the amount classified as demand-related being attributable to usage for peaking or capacity purposes and the costs classified as energy-related being attributable to usage for baseload or energy purposes.

Therefore, the type of demand-related allocation factor used should reflect how the hydro resources are designed or used to satisfy peak demands throughout the year. To the extent that the hydro plants are designed or used to help meet peak loads throughout the entire year, then a 12 CP method is appropriate for allocating the associated demand-related hydro costs. If the hydro plants are primarily designed or used to help meet peak loads during only a few months of the year, then methods such as 3 CP or 4 CP would be more appropriate. If the detailed accounting data is available, different demand-related allocation factors could be used for allocating demand-related costs for different plants or groups of plants. For demand-related costs associated with peaking thermal plants, the allocation factor should reflect the CP demands in the months when the thermal plants are primarily used.

Although not used by any of the utilities in the jurisdictional survey, another option for allocating BC Hydro's hydro costs that we believe has merit is to use the Average and Excess (A&E) allocation method. Using this method, generation costs are usually classified as 100 percent demand-related. This method then allocates generation costs to classes using factors that combine the classes' average demands and NCP demands, thus acknowledging that the generation resources are used to supply both capacity and energy needs. A&E allocation factors reflect two cost components. The first component of each class's allocation factor is its portion of total average demand, or energy consumption times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor". It is the proportion of the difference between the sum of all classes' NCPs and the system average demand.[6]

Regarding IPP and purchased power resources, we believe these costs should be classified and allocated based on either (1) their fixed versus variable payment obligations (with fixed payment for fixed capacity purchases classified as demand, and variable or uncertain capacity purchases classified as energy) or (2) whether they were originally contracted predominantly for or currently providing BC Hydro fixed capacity or variable energy.

The net income from BC Hydro's Powerex subsidiary helps to offset generation costs for all customer classes. As such, the current approach of classifying and allocating subsidiary net income consistent with the aggregate classification and allocation results for generation resources is appropriate.

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[6] *Electric Utility Cost Allocation Manual*, published January 1992, by the National Association of Regulatory Utility Commissioners.

In summary regarding BC Hydro's generation COS methodology:

- We recommend that BC Hydro consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.
- For allocating demand-related hydro costs, we recommend BC Hydro first analyze how hydro units are designed or being used to serve peak loads throughout the year. To the extent that the hydro plants are designed or used to meet peak loads throughout the entire year, then a 12 CP method is appropriate. If the hydro plants are primarily designed or used to help meet peak loads during only a few months of the year, then methods such as 3 CP or 4 CP would be more appropriate.
- As an alternative approach option for hydro costs, we recommend BC Hydro consider using the A&E method for allocating demand-related hydro costs.
- We recommend that BC Hydro continue to classify peaking thermal plant in service costs as demand-related and also classify associated O&M costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.
- For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the CP demands in the months when the thermal plants are primarily used.
- We recommend that BC Hydro modify the classification of IPP and other purchased power obligations to reflect either fixed versus variable payment obligations or capacity versus energy usage.
- We recommend that BC Hydro continue using the split between demand-related and energy-related generation revenue requirements, excluding subsidiary income, to classify subsidiary net income.

It should be noted, however, that evaluating the feasibility of performing the sub-functionalization of generation costs required for several of these suggested approaches goes beyond the scope of this review.

Transmission COS Methodologies

Based on the results of the jurisdictional review and our review of the BC Hydro system and BC Hydro's COS methodology, we believe it is appropriate for BC Hydro to evaluate the feasibility of sub-functionalizing its transmission assets and associated costs based on how those assets are used to transmit power. For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, it would be most appropriate for the costs of these resources to be classified and allocated in the same manner as costs for the generation asset.

For backbone or network transmission, use of BC Hydro's current Demand Only method for classification is reasonable. When selecting an allocation method, consideration should be given as to how these transmission assets, in part or as a whole, are designed and used and BC Hydro's load patterns. For example, it may be appropriate to sub-functionalize transmission plant in service or O&M costs between the southern interior region and other areas using different types of allocation factors for each. Based on testimony related to the 2007 RDA, it appears that summer loads are of most importance to that portion of the system while loads during other times of the year may be of more importance for other parts of the system. For transmission/subtransmission assets that essentially serve as radial high voltage distribution systems, the Demand Only method for classification is reasonable and consideration should be given to using the type of demand-related allocation factors used for substation distribution costs, or 1 NCP.

In summary, regarding BC Hydro's transmission COS methodology:

- For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, we believe it is most appropriate for the costs of these resources to be classified and allocated in the same manner as costs for the generation resources.
- For backbone or network transmission, we recommend BC Hydro's use of the current Demand Only method for classification should continue to be used. When selecting an allocation method, consideration should be given as to how these transmission assets are designed and used and BC Hydro's load patterns. It may be appropriate to sub-functionalize these transmission costs between areas, such as the southern interior and other areas, using different types of allocation factors for each. Based on testimony related to the 2007 RDA, it appears that summer loads are of most importance to that portion of the BC Hydro system while loads during other times of the year may be of more importance for other parts of the system.
- For transmission/subtransmission assets that essentially serve as a radial high voltage distribution system, we recommend that the Demand Only method for classification should continue to be used and consideration should be given to using 1 NCP as the demand allocator.

It should be noted, however, that the feasibility of performing the sub-functionalization of transmission costs required for some of these suggested approaches goes beyond the scope of this review.

Distribution and Customer Care COS Methodologies

Our review of the 2012 Distribution System Study identified a number of issues related both to methodology and application that we discussed with BC Hydro staff and the preparer of that study. We recommend that the distribution system study be reexamined and updated prior to its use by BC Hydro for use in its COS study.

The jurisdictional survey indicates that few utilities utilize the results of a recently prepared minimum system study and/or zero-intercept study in their COS methodology. More typically, the various types of distribution costs are classified as either 100 percent demand-related or 100 percent customer-related, with broad classification of the distribution system's sub-functionalized costs.

Consistent with the results of the jurisdictional review, it is reasonable for BC Hydro to classify distribution substation costs as 100 percent demand-related and distribution services and meter costs as 100 percent customer-related.

Generally, the use of minimum system studies and zero intercept studies in COS studies is declining and sub-functionalized distribution costs are being classified as either 100 percent demand-related or 100 percent customer-related. This is in part due to the difficulties with collecting the data necessary to accurately complete these studies, as well as the complexity of the studies themselves. An approach that has been gaining acceptance in the U.S. is to clearly separate, for classification purposes, certain identifiable plant in service that (1) provides service only to individual customers, or customer-related plant in service, from (2) plant in service that is part of the interconnected distribution network, or demand-related plant in service. Typically, the customer-related plant in service includes services and meters and the demand-related plant in service includes substations, lines, and transformers.

For the four utilities in the jurisdictional review that classify costs for distribution lines as both demand-related and customer-related, the percentage classified as demand-related ranged from 60 percent to 79 percent. For the two utilities in the jurisdictional review that classify transformer costs as both demand-related and customer-related, the percentage classified as demand-related ranged from 64 percent to 73 percent. Therefore, the 75/25 split proposed by BC Hydro in the 2007 RDA and the 65/35 split from the 2007 BCUC order are both generally within the ranges reported by the utilities in the jurisdictional review.

The majority of the utilities in the jurisdictional review use weighted number of customers for purposes of allocating transformer, services, and meter costs. In BC Hydro's current COS study, all customer-related distribution costs area allocated using unweighted number of customers.

As a result of the outcome of the 2007 RDA, BC Hydro currently classifies customer care costs as 65 percent demand-related and 35 percent customer-related. However, common practice is to classify most or all customer care costs as customer-related. Therefore, we believe BC Hydro should change how they classify their customer care costs to customer-related.

In summary regarding BC Hydro's distribution COS methodology:

- We recommend BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.
- We recommend BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.

- We recommend if possible that BC Hydro consider using more direct assignment of distribution costs (e.g., transformers, services, and meters) based on fixed asset records, or consider using the weighted number of customers when calculating the allocation factors for transformer, services, and meter costs.
- We recommend BC Hydro review and revise the Distribution System Study to be more consistent with the theoretical foundation of the minimum system method and zero-intercept method as described in the *1992 NARUC Manual*, prior to its use by BC Hydro. As an alternative, we recommend BC Hydro consider classifying distribution substation, lines, and transformer costs as all demand-related and services and meter costs as all customer-related.
- We recommend that BC Hydro classify most, if not all, customer care costs as customer-related.

It should be noted, however, that the feasibility of performing the sub-functionalization of distribution costs required for some of these suggested approaches goes beyond the scope of this review.

DSM COS Methodologies

DSM resources are valuable to BC Hydro in that these resources reduce the utility's need for both energy and capacity resources. As such, classifying and allocating DSM costs consistent with the aggregate classification and allocation results for other generation and transmission resources would be clear and representative of the cost savings these DSM resources provide. As such, an option for BC Hydro to consider would be to functionalize DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service. The current approach of using classified plant in service costs for classifying both generation-related and transmission-related DSM costs would then be consistent with the functionalization approach.

We recommend that BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service. As such, the functionalization approach would be consistent with the classification approaches.

Appropriate R/C Ratios

In general, all utilities in the jurisdictional review indicated they advocate movement of customer class R/C ratios more towards cost based rates in their rate design proposals, but other objectives such as rate stability and minimizing customer impacts are also of importance. No significant rebalancing of BC Hydro's rates has occurred since the 2007 RDA. Along with changes in costs and changes in the COS methodology required by the BCUC Order from the 2007 RDA as discussed above, the customer class R/C ratios in BC Hydro's 2012 COS study range from 87 percent to 126 percent.

It is our view that the 90 percent to 110 percent range of reasonableness for customer class R/C ratios proposed by BC Hydro in the 2007 RDA, as well as the BCUC discussed 95 percent to 105 percent range from the 2007 Order, are both reasonable target ranges for R/C ratios and consistent with generally accepted utility practice. Essentially we believe this is a policy decision that should rest with BC Hydro's decision makers. Currently by law, BC Hydro is limited on rebalancing customer classes to no more than two percentage points per year compared to the R/C ratio for that class immediately before a rate increase.

We also believe that it is important for BC Hydro to have some flexibility in making decisions regarding rate design for other types of objectives. We believe that some variability from a unity R/C ratio target should be acceptable in order to provide general rate consistency over time. Either of the two ranges of reasonableness would be consistent with the intent of the COS methodology, and target R/C ratios should be considered as one important element of ratemaking to be evaluated along with other ratemaking goals and objectives (e.g., rate consistency over time, gradual implementation of rate changes, etc.).

In summary regarding BC Hydro's R/C and related rate design policies:

- We recommend BC Hydro consider adopting a range of reasonableness for customer class R/C ratios, with the goal of making changes in rate levels gradually over a several year period consistent with this and other ratemaking objectives when customer classes are outside of the target R/C range.
- We recommend BC Hydro consider more explicitly developing a policy for how rapidly customer classes should be moved towards this range of reasonableness for R/C ratios with consideration also given to other ratemaking goals and objectives and the current legal limit on rebalancing (i.e., no more than two percentage points per year compared to the R/C ratio for that class immediately before the increase).

Sub-Functionalization

One general observation we made from our review of the BC Hydro COS model is that BC Hydro utilized a more limited sub-functionalization of its revenue requirement compared with the levels being used by other utilities of similar size and complexity. Significantly greater detailed information for both costs and operational aspects of the utility may be available to BC Hydro, and this more detailed information may add value if incorporated into the COS methodology.

As indicated above, we think BC Hydro would benefit from greater sub-functionalization of its revenue requirements than is currently used in the COS model. We recommend BC Hydro consider adopting a greater level of detail in the breakdown of both operating costs and plant asset accounts in its COS model and analysis in order to avail itself to greater direct assignment of costs and greater transparency in assigning costs more accurately to its customer classes.

Appendix A
UTILITIES IN JURISDICTIONAL REVIEW

Please see the table showing characteristics of utilities included in the jurisdictional review on the following page.

Table A-1
Comparison of Utilities for Jurisdictional Review

	Peak Season	Hydro Power % (incl purchases)	Number of Electric Customers	Total Electric Sales Revenues	Ownership	Electric Functions	Purchased as % of total kWh	Exports as % of kWh Sales	Service Area	Last Filing/COS Analysis	Docket	Type of RR	Type of COS
Avista	Winter	51%	360,000	$800 million	Private	Vertically integrated	49%	31%	Electric and natural gas customers in northern Idaho (1)	2012	AVU-E-12-08	Historical	Embedded
									Electric and natural gas customers in eastern Washington	2011	UE-120436	Historical	Embedded
Bonneville Power	Winter	80%	146 (455 transmission customers)	$3,200 million	Government	G&T (generation and transmission)	10%	8%	Electric customers in the Pacific Northwest including utilities, federal agencies, industries, and port districts	2012	BP-14	Prospective	Embedded (2)
Hydro-Québec Distribution	Winter	98%	4,060,000	$12,100 million	Government	Four divisions (G & T & D & Equipmt Services) with only T & D being regulated (3)	16%	14%	Quebec	2012	Demande R–3814–2012	Prospective	Embedded
Idaho Power	Summer	63%	410,000	$1,000 million	Private	Vertically integrated	15%	26%	Eastern Oregon and Southern Idaho	2011	UE 233 (Oregon)	Prospective	Embedded (4)
										2011	IPC-E-11-08 (Idaho)		
Manitoba Hydro	Winter	96%	540,000	$1600 million	Government	Vertically integrated	3%	33%	Maintoba	2012	2012/13 AND 2013/14 GENERAL RATE APPLICATION	Prospective	Embedded (5)
Newfoundland Power	Winter	69%	240,000	$600 million	Private	Vertically integrated, but most power needs are met with purchased power	90% from Newfoundland and Labrador Hydro	<1%	Approximately 86% of consumers in province	2012	2013/2014 General Rate Application	Historical	Embedded
Portland General Electric	Winter	42%	810,000	$1,800 million	Private	Vertically integrated	58%	14%	Portland and surrounding communities	2010	UE-215	Prospective	Marginal
Puget Sound Energy	Winter	54%	1,100,000	$2,200 million	Private	Vertically integrated	54%	23%	Puget Sound region of Western Washington	2011	UE-111048	Historic	Embedded
Seattle City Light	Winter	92%	400,000	$800 million	Government	Vertically integrated	56%	41%	Seattle and parts of its metro areas	2012	NA	Prospective	Marginal
BC Hydro	Winter	89%	1,870,000	$4,400 million	Government	Vertically integrated	40%	32%	British Columbia	2007	2007 Rate Design Application	Prospective	Embedded

(1) Also services natural gas customers in southern and eastern Oregon.
(2) Marginal costs are used for rate design purposes.
(3) The Regie de L'energie only regulates the transmission and distribution functions. Beyond their heritage pool volume, Hydro-Quebec Production competes with other generators in response to Hydro-Quebec Distribution's calls for tenders, which determine the cost of electric power other than the heritage pool. Heritage pool power if provided at fixed $/kWh rate to Distribution.
(4) Energy-related production plant and expenses are allocated based on annual energy at generation with monthly marginal energy cost weightings (averaged with unweighted values).
(5) Energy-related production plant and expenses are allocated based on annual energy at generation with seasonal/time-of-day marginal energy cost weightings.

Classification Methodologies for Generation and Transmission Resources

The following approaches are used by the utilities surveyed to classify generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, and energy conservation program costs:

- **Commission Ordered –** One utility uses this approach. BC Hydro classifies its hydro plant in service as 55 percent demand-related and 45 percent energy-related based on the 2007 BCUC Order.
- **Demand Only** – Using this approach, generation plant in service and associated O&M expenses are classified as 100 percent demand-related.

  Seven utilities, including BC Hydro, use this approach as follows:

  - Avista Corporation–Idaho, Portland General, and Newfoundland Power classify all transmission plant in service and associated O&M expenses as demand-related.
  - BC Hydro uses this approach to classify plant in service associated with peaking thermal generation, diesel generation in integrated areas, and transmission assets and lines.
  - Hydro-Québec Distribution classifies network transmission costs and customer interconnection costs as 100 percent demand-related.
  - Idaho Power uses this methodology to classify peaking thermal plant in service costs, as well as certain related O&M costs excluding fuel, and DSM incentive payments. They also use it to classify all transmission plant in service costs and associated O&M costs, with the exception of costs associated with wheeling by others.
  - Manitoba Hydro classifies all transmission and subtransmission plant in service, and associated O&M costs, as demand-related.
  - Newfoundland Power uses this methodology to classify non-peaking thermal plant in service and peaking thermal plant in service, as well as associated O&M costs including fuel, and DSM incentive account expenses.

- **Derived from Classified Generation Plant Costs –** Using this approach, the percentage of total generation plant in service that is classified as demand-related (versus energy-related) is first calculated. Then the share of costs being classified that is attributable to demand is equal to that percentage.

  Two utilities use this approach as follows:

  - Avista Corporation–Idaho uses the demand/energy split for total classified generation plant in service to classify purchased power costs between demand and energy, as well as DSM investment in rate base, related amortization expense, and net income from wholesale power sales.
  - BC Hydro uses the demand/energy split for total classified generation plant in service to classify O&M costs for hydro and peaking thermal generation resources, as well as generation-related DSM costs.

- **Derived from Classified Transmission Plant Costs –** Using this approach, the percentage of total transmission plant in service that is classified as demand-related (versus meter-related) is first calculated. Then the share of costs being classified that is attributable to demand is equal to that percentage.

  One utility uses this approach. BC Hydro uses the demand/meter split for classifying transmission assets, lines, and meters, domestic transmission costs for wheeling of power from heritage resources as well as transmission-related DSM costs.

- **Derived from Classified Generation Revenue Requirement –** One utility uses this approach. BC Hydro classifies subsidiary net income based on the classified generation revenue requirement excluding subsidiary net income.

- **Derived from Other Classified O&M Costs –** One utility uses this approach. Newfoundland Power functionalizes, classifies, and allocates conservation and DSM general costs based on the percentages of corporate administration and general expenses functionalized, classified, and allocated to customer classes.

- **Energy Only –** Using this approach, generation and transmission plant in service and associated O&M expenses are classified as 100 percent energy-related.

  Six utilities use this approach, including BC Hydro, as follows:

  - Avista Corporation–Idaho uses this methodology to classify hydro water costs as well as non-peaking and peaking fuel costs.
  - BC Hydro uses this methodology to classify (1) fuel costs associated with thermal generation, (2) plant in service, O&M costs, and fuel costs associated with diesel generation in non-integrated areas, (3) purchased power costs including market purchases and capacity and energy payments associated with purchases from IPPs, and (4) revenues from power sales including surplus sales and sales to Powerex.

  - BPA's cost of COS methodology generally treats all generation and purchased power-related costs, as well as conservation and energy efficiency costs, as energy-related for subsequent allocation to customer classes using a combination of energy-related allocation factors and direct assignment. It also treats all transmission O&M costs as energy-related.
  - Hydro-Québec Distribution uses this methodology to classify purchased power costs from non-heritage resources.
  - Idaho Power uses this methodology for classifying certain O&M costs associated with hydro and non-peaking thermal plant in service that are not classified using the system load factor approach including non-peaking plant fuel costs. In addition, this methodology is also used for classifying certain O&M costs associated with peaking thermal plant O&M costs, excluding fuel, that are not classified using the energy-only approach. Finally, it is used to classify costs associated with wheeling by others and net income from wholesale power sales.
  - Manitoba Hydro's methodology generally treats all generation and purchased power-related costs as energy-related for subsequent allocation to customer classes using weighted energy non-peaking-related allocation factors.

- **Hydro Peak Credit –** One utility uses this approach. Avista Corporation–Idaho uses the ratio of its current replacement cost per kilowatt (kW) of their peaking units to the current replacement cost per kW of their hydro plant to classify hydro plant and related O&M costs, excluding water costs. The share of hydro costs attributable to demand is equal to the ratio.

- **Marginal Costs –** Using a marginal cost approach, utilities generally (1) calculate marginal production and transmission capacity and energy costs for a test year, thus identifying the demand-related and/or energy-related portions of marginal costs, (2) allocate demand-related and/or energy-related components of marginal costs to customer classes, and (3) allocate embedded costs for generation and transmission based on the percentages by class of total allocated marginal capacity and energy costs.

  Two utilities use somewhat different approaches to calculate marginal generation costs as follows:

  - **Generation Marginal Costs – Demand and Energy –** Portland General separately calculates long-run marginal production capacity and energy costs for a test year, thus identifying the demand-related and energy-related portions of marginal generation costs.
  - **Generation Marginal Costs – Energy Only –** Seattle City Light uses forecasted hourly wholesale per megawatt hour (MWh) market prices plus externality costs as their marginal energy generation costs, so all marginal generation costs are considered energy-related.

One utility, Seattle City Light, uses this approach and calculates marginal transmission costs as follows:

- o **Transmission Marginal Costs – Demand Only –** First, annualized costs for transmission service in Seattle City Light's service area are calculated. Historical three-year annual average transmission O&M costs are adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent demand-related.
- o **Transmission Marginal Costs – Energy Only –** Seattle City Light calculates marginal costs for long-distance transmission service as BPA's monthly transmission service price on a $ per MW basis multiplied by estimated peak system load multiplied by 12. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent energy-related.

- **Meter Only** – One utility uses this approach. BC Hydro classifies transmission meters as 100 percent meter related.
- **Revenue Only –** One utility uses this approach. Seattle City Light classifies 100 percent of their net income from wholesale power sales as revenue related.
- **Supplier COS Results** – One utility uses this approach. Newfoundland Power purchases the majority of their power from Newfoundland and Labrador Hydro. Newfoundland Power classifies purchased power based on Newfoundland and Labrador Hydro's classified cost to serve Newfoundland Power for the 2007 forecast test year. Newfoundland and Labrador Hydro use the System Load Factor method to classify hydro resources and associated transmission resources, and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power are classified as demand-related.
- **Supply Cost Savings –** One utility uses this approach. Newfoundland Power uses it for classifying conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage. The programs are classified between demand and energy reflective of the supply cost savings that occurred (95 percent to production energy, 2 percent to production demand, and 3 percent to substation demand).
- **System Load Factor** – Using this method, the utility's electric system load factor for the test year is first calculated as the ratio of system average demand divided by system peak demand. Then the share of plant in service and/or associated O&M costs attributable to demand is equal to one minus the load factor.

  Four utilities use this approach as follows:

- Avista Corporation–Washington uses this methodology to classify (1) all of its hydro, non-peaking thermal, peaking thermal, and renewables plant costs, (2) associated generation O&M costs including fuel and water costs, (3) purchased power costs, (4) transmission plant in service costs, (5) associated transmission O&M costs, and (6) net income from wholesale power sales.
- Hydro-Québec Distribution uses this methodology to classify purchased power costs from heritage resources and generation-related transmission costs and costs for interconnections with neighboring systems based on the load factor of Hydro-Québec Transmission Division (TransÉnergie).
- Idaho Power uses this methodology for classifying (1) hydro plant in service and non-peaking thermal plant in service, (2) certain O&M costs associated with hydro and non-peaking thermal plant including hydro water costs, (3) purchased power costs, and (4) customer assistance costs for energy efficiency programs..
- Newfoundland Power uses this methodology to classify hydro plant in service and related O&M costs including water costs.

* **Thermal Peak Credit** – Two utilities use this methodology, but their approaches somewhat differ as follows:
  - Avista Corporation–Idaho uses the ratio of their current replacement cost per kW of their peaking units to the current replacement cost per kW of their thermal plant for classification of costs associated with non-peaking thermal resources and renewables, excluding thermal fuel costs.
  - Puget Sound Energy's approach uses the ratio of the cost per kW-year of generating capacity for a proxy peaking generating resource to the cost per kW-year of generating capacity for a proxy baseload generating resource (thermal peak credit). The share of production costs attributable to demand is equal to the ratio. Puget Sound Energy uses this approach to classify all of its generation plant in service accounts and related O&M costs including water costs, thermal fuel costs, and purchased power costs, as well as weatherization customer assistance costs. Using this method, the ratio of the per unit cost of peaking plant divided by per unit cost of baseload plant is first calculated. The share of generation plant in service and associated O&M costs attributable to demand is equal to the ratio. Puget Sound Energy also uses the thermal peak credit approach for classifying transmission plant in service and associated O&M costs. Peak credit percentages are applied to transmission costs by Puget Sound Energy under the theory that transmission lines are constructed to deliver energy and capacity provided by generating plant, and in the same proportion as it is being provided.

- **Water Rental Rates –** One utility uses this approach. BC Hydro allocates water rental costs based on the underlying fixed and variable rental charges.

Allocation Methodologies for Generation and Transmission Resources

The following approaches are used by the utilities in the jurisdictional review to allocate demand-related, revenue-related, and meter-related generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, conservation costs:

- **1 CP –** This approach first determines the system peak that is the highest system demand during the entire year. Then each class's CP percentage is the ratio of that class's demand at the time that the system peak occurred divided by the system peak demand at that time that the system peak occurred.

  Two utilities use this approach as follows:

  - Hydro-Québec Distribution uses 1 CP for allocation of demand-related transmission O&M expenses, with the exception of costs associated with customer connections.
  - Newfoundland Power uses 1 CP to allocate demand-related hydro, non-peaking thermal, and peaking thermal generation plant in service costs and associated demand-related O&M costs. In addition, they use it to allocate demand-related costs for (1) conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage, (2) transfers to the reserve stabilization fund associated with their demand management incentives, and (3) transmission plant in service and associated O&M.

- **3 CP –** This approach first determines the three months with the highest monthly system peak demands over a twelve-month period, and then determines each class's demand at the time of those three monthly system peak demands. Each class's 3 CP percentage is then determined as the ratio of the sum of the class's demands at the time of the three highest system peaks divided by the sum of the three highest system peak demands.

  One utility uses this approach. Idaho Power uses 3 CP during the summer months to allocate demand-related plant in service and associated O&M costs for peaking resources that are primarily used during the summer as well as demand-related DSM costs for incentive payments and costs for customer assistance related to energy efficiency programs.

- **4 CP –** This approach first determines the four months with the highest monthly system peak demands over a twelve-month period, and then determines each class's demand at the time of those four monthly system peak demands. Each class's 4 CP percentage is then determined as the ratio of the sum of the class's demands at the time of the four highest system peaks divided by the sum of the four highest system peak demands.

Two utilities use this approach as follows:

- BC Hydro uses this approach to allocate demand-related hydro O&M and water rental costs and demand-related O&M costs associated with peaking thermal generation. BC Hydro also uses this approach to allocate demand-related O&M associated with transmission assets, lines, and meters, and demand-related transmission costs related to heritage resources. Finally, BC Hydro uses this approach to allocate demand-related DSM costs and subsidiary net income.
- Portland General allocates marginal capacity-related generation O&M costs using the demands from the months of January, July, August and September. They also allocate demand-related transmission O&M costs using the demands from the same four months.

- **12 CP –** This approach first determines the highest system peak demand for each month over a twelve-month period, and then each class's demand at the time of each system peak. Each class's 12 CP percentage is then determined by taking the ratio of the sum of the class's demands at the time of the twelve system peaks dividing by the sum of the twelve system peak demands.

  Three utilities use this approach as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho both use this approach to allocate all demand-related generation and transmission plant in service costs and associated O&M costs as well as demand-related net income from wholesale sales. Avista Corporation–Idaho also uses it to allocate amortization expenses related to weatherization and DSM investment. They indicated that although they are usually winter peaking utilities, they experience high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.
  - Idaho Power also uses the 12 CP approach to allocate demand-related plant in service and associated costs for hydro and non-peaking thermal resources. They also use it to allocate demand-related transmission plant in service and related O&M costs.

- **1 NCP –** This approach first determines each class's NCP load during the year regardless of when the other class's or system peak loads occur. Then each class's NCP percentage is the ratio of that class's NCP demand at the time class peaked divided by the sum of all the classes' NCP demands.

  Two utilities use this methodology:

- Hydro Quebec Distribution uses this approach to allocate demand-related transmission O&M expenses associated with customer connections.
- Manitoba Hydro uses this approach to allocate demand-related O&M costs associated with sub-transmission.

- **Average of Loads During Select Periods –** This approach first determines the average loads of each class during selected period(s). Each class's allocation percentage is the ratio of that class's average load during the selected period(s) divided by the sum of all classes' loads during the selected period(s).

  Three utilities use this approach as follows:

  - Manitoba Hydro utilizes a summer and winter coincident demand peak allocator based upon the average of the highest 50 peak hours in each season, adjusted for losses, for transmission facilities larger than 100 kV. Peak loads on the transmission system are approximately equivalent in magnitude in both seasons. High winter loads are caused by domestic retail space heating, while summer loads can be comparatively high because of export sales.
  - Puget Sound Energy allocates (1) demand-related generation plant in service costs and related O&M costs, (2) demand-related transmission plant in service and related O&M costs, and (3) weatherization customer assistance expenses based on each class's average contribution to the average hourly class loads that occurred coincident with the top 75 system hourly loads during the test year. The percentage allocated to each class is the ratio of that class's average demand during the 75 peak hours divided by the average system peak demand during those 75 peak hours.[7]
  - Seattle City Light uses class contributions to the highest average system MW load in 48 costing periods during the year to allocate marginal demand-related costs for transmission in their service area.[8]

- **Derived from Marginal Allocated Revenue Requirements -** Seattle City Light's net revenues from wholesale sales are allocated based on the shares of the total marginal revenue requirements allocated by marginal cost shares.

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7 Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours.

8 For the last several rate reviews, estimates of projected consumption for aggregations of the hourly data were used (four costing periods each month or 48 per year) with the expectation that statistical errors in individual hours would, on average, balance out in the forecast periods. The total energy estimated for each period is then divided by the number of hours in the period to estimate the expected average hourly consumption. The coincident peaks for classes as total groups are then determined for the costing period with the largest hourly average consumption. Class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate costs.

- **Derived from Other Demand-Related Allocated Costs –** One utility uses this approach. Newfoundland Power allocates demand-related conservation and DSM general costs based on the percentage allocations of total demand-related corporate administration and general expenses to customer classes. They also allocate demand-related curtailable service options costs based on the percentage allocations of total demand-related O&M costs.
- **Meter Replacement Costs –** One utility uses this approach. BC Hydro uses relative meter replacement costs for customers served at transmission voltages to allocate meter-related O&M costs for transmission assets, lines, and meter, and demand-related domestic transmission costs related to heritage resources. BC Hydro also uses this approach for allocating transmission meter-related DSM costs.
- **Relationship of Class to System Utilization Factors –** Using this approach, the ratio of class to system utilization factors is a key component in the calculation of the allocation factors.

  One utility uses this approach. Hydro-Québec Distribution allocates demand-related purchased power costs from heritage resources based on the relationship between the specific load factor (i.e., utilization factor), of each class of consumers and the total distribution load factor. A class load factor, or utilization factor, is equal to the class average annual MW divided by the class non-coincident peak MW within a defined 300-hour peak period. For example, assuming a class load factor of 48.0 percent, class power losses of 9 percent, and system power losses of 8 percent, and heritage pool demand-related costs of 0.96¢ per kWh, the allocated cost to the class would be 0.96¢/kWh X 65.6%/48.0% X (1+9%)/(1+8%) = 1.32 ¢/kWh. This cost would then be multiplied by class annual energy consumption with appropriate adjustments for losses.

The following approaches are used by the utilities in the jurisdictional review to allocate energy-related, revenue-related, and meter-related generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, conservation costs:

- **Annual Energy at Generation –** Using this approach, costs are allocated to each class based on the ratio of annual energy needed to serve that class, including adjustment for losses, divided by the sum of the annual energy needed to serve all customer classes.

  Eight utilities use this methodology as follows:

  - Avista Corporation–Idaho uses this approach for allocating (1) energy-related generation plant in service, associated O&M costs, and purchased power costs, (2) energy-related amortization expenses for weatherization and DSM investment, and (3) energy-related net income from wholesale power sales.

- Avista Corporation–Washington, uses this approach for allocating energy-related generation and transmission plant in service, associated O&M costs, purchased power costs, and net income from wholesale power sales.
- BC Hydro uses this approach to allocate (1) energy-related O&M costs for hydro, peaking thermal, and diesel generation in non-integrated areas, (2) energy-related water renal and fuel costs, (3) energy-related purchased power costs, and (4) energy-related subsidiary net income and revenues from power sales.
- Hydro-Québec Distribution takes energy-related heritage pool costs on a cents per kWh basis multiplied by class annual energy consumption with appropriate adjustments to determine each class's share of energy-related heritage pool costs. They also use this approach for allocating energy-related transmission costs for generation-related transmission and interconnections with neighboring systems.
- Newfoundland Power also uses this approach to allocate energy-related costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage.
- Puget Sound Energy uses this approach for allocating energy-related generation plant in service, associated O&M costs, and purchased power costs.
- Seattle City Light uses class contribution percentages to average annual system demand, or aMW, to allocate marginal costs for long-distance transmission services.

- **Derived from Other Energy -Related Allocated Costs –** One utility uses this approach. Newfoundland Power allocates conservation and demand management general costs based on the percentage allocations of energy-related corporate administration and general expenses to customer classes.
- **Direct Assignment/Annual Energy at Generation (aMW) –** One utility uses this approach. BPA uses a combination of direct assignment and the Annual Energy at Generation method, or aMW, to allocate energy-related generation and transmission costs and conservation and energy efficiency costs.
- **Weighted Annual Energy at Generation –** Using this approach, costs are allocated to each class based on the ratio of annual energy needed to serve that class, weighted for various factors and adjusted for losses, divided by the sum of weighted annual energy for all customer classes.

  Five utilities use variations of this approach as follows:

  - Hydro-Québec Distribution allocates purchased power costs from non-heritage resources using an "hourly method" that consists of (1) the establishment of an hourly weighted-cost for all the different supply contracts on the basis of their duration during the year and (2) the attribution of those costs on the basis of the hourly consumption for each customer class.

- Idaho Power uses allocation factors derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocation factors used in their approach.
- Manitoba Hydro’s energy-related generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro’s Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Manitoba Hydro’s approach accounts for the differences in economic value of the underlying resources to supply energy by timeframe.
- Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in dollar per kWh to allocate marginal energy-related generation costs.
- Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly dollar per MWh market energy prices plus forecasted hourly dollar per MWh externality costs to determine allocated marginal energy-related costs.

Also, the two utilities that use primarily a marginal COS approach use a form of the Derived from Other Allocated Costs method to allocate embedded generation and transmission costs in that costs are allocated using the percentages by class of marginal capacity and/or energy costs.

Classification Methodologies for Distribution Resources

The following approaches are used by the utilities surveyed to classify distribution plant in service costs and associated O&M expense:

- **Commission Ordered –** One utility uses this approach. BC Hydro uses the 65 percent demand-related and 35 percent customer-related split as ordered in the 2007 BCUC Order to classify distribution and customer care O&M costs.
- **Computation Method –** One utility uses this approach. Idaho Power classifies distribution lines and transformer plant in service costs and associated O&M costs using a fixed and variable ratio computation method used in prior rate cases. The ratios are periodically updated according to

system capacity utilization measurements based on three-year average load duration curves.

- **Customer Only –** Using this approach, distribution plant in service and/or O&M expenses are classified as 100 percent customer-related.

  Seven of the utilities use this approach to classify various types of distribution plant in service and O&M expenses as follows:

  - Hydro-Québec Distribution and Puget Sound Energy use this approach to classify distribution transformer, services, and meter plant in service and associated O&M expenses.
  - Avista Corporation–Washington, Avista Corporation–Idaho, Idaho Power Company–Idaho, Manitoba Hydro, and Newfoundland Power use this approach to classify distribution services and meter plant in service and associated O&M expenses

- **Demand Only –** Using this approach, distribution plant in service and/or O&M expenses are classified as 100 percent demand-related.

  Seven of the utilities use this approach to classify various types of distribution plant in service and O&M expenses as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to classify all distribution plant in service and related O&M costs except for services and meters plant in service and related O&M costs.
  - Hydro-Québec Distribution uses this approach to classify distribution substation plant in service and associated O&M expenses.
  - Idaho Power–Idaho and Newfoundland Power use this approach to classify distribution substation plant in service and related O&M expenses.
  - Manitoba Hydro uses this approach to classify distribution substation and transformer plant in service and related O&M expenses.
  - Puget Sound Energy uses this approach to classify plant in service and related O&M costs for distribution substations as well as distribution lines.

- **Historic Study** – One utility uses this approach. Manitoba Hydro classifies distribution lines plant in service costs and related O&M costs using the results of a study completed in 1990.

- **Marginal Costs** – In general, utilities using a marginal cost approach (1) calculate marginal demand-related and/or customer-related distribution costs for a test year, (2) allocate demand-related and/or customer-related components of marginal costs to customer classes, and (3) allocate embedded costs for distribution based on the percentages by class of total allocated marginal capacity and energy costs.

Two utilities use various different approaches to classify marginal distribution costs as follows:

- o **Distribution Services Marginal Costs – Demand Only –** Portland General treats marginal costs for distribution services as demand-related.
- o **Distribution Services Marginal Costs – Demand Only –** Seattle City Light treats marginal costs for distribution services as demand-related.
- o **Distribution Substations Marginal Costs – Demand Only –** Portland General and Seattle City Light treat marginal costs for distribution substations as demand-related.
- o **Distribution Lines Marginal Costs – Demand Only** – Portland General and Seattle City Light treat marginal costs for distribution lines as demand-related.
- o **Distribution Transformers Marginal Costs – Customer Only –** Portland General treats marginal costs for distribution transformers as customer-related.
- o **Distribution Transformers Marginal Costs – Demand Only** – Seattle City Light treats marginal costs for distribution transformers as demand-related.
- o **Distribution Meters Marginal Costs – Customer Only –** Portland General and Seattle City Light treat marginal costs for meters as customer-related.

- **Minimum System Study –** Using this method, it is assumed that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. In order to determine the customer-related portion of the utility's distribution system, it is assumed that the utility's lines, transformers, services, etc., are all replaced by the corresponding minimum size assets. Using replacement costs, the value for the minimum system distribution system is compared to the value of replacing all the poles, lines, transformers, services, etc. The ratio of the value of the minimum system to the value of the replacement of all the poles, lines, transformers, services, etc. reflects the percentage of the customer-related portion to be used in categorizing costs.

  Two of the utilities use this approach. Both Hydro-Québec Distribution and Newfoundland Power use this approach to classify distribution plant in service costs and associated O&M costs.

- **Zero Intercept Analysis –** Using this method, data on costs of various sizes of equipment is first gathered to determine a common investment per customer-related to a no-demand situation. This method uses a linear regression on the equipment cost data to determine the dollar value of the common investment in a specific type of distribution plant. The point of zero intercept is the customer-related per unit cost. Multiplying that cost by the number of customers yields the customer-related cost of that type of distribution plant in service. The remainder of the cost is demand-related.

One utility uses this approach. Newfoundland Power classifies distribution transformer plant in service and associated O&M costs using the zero intercept analysis.

Allocation Methodologies for Distribution Resources

The approaches used by the surveyed utilities for allocation of demand-related distribution plant in service and associated O&M costs are summarized below:

- **1 NCP –** Five utilities use this approach as follows:
  - BC Hydro uses this approach to allocate demand-related distribution and customer care O&M costs.
  - Idaho Power, Manitoba Hydro, and Newfoundland Power use this approach to allocate all demand-related distribution plant in service and associated O&M costs.
  - Portland General uses 1 NCP to calculate allocated marginal distribution substation and feeder costs. Marginal substation costs are allocated to each rate schedule by multiplying marginal substation cost dollar per kW multiplied by class NCP. Marginal feeder costs for each rate schedule are allocated to each rate schedule by multiplying average marginal feeder cost dollar per kW multiplied by class NCP.
- **12 NCP –** Three utilities use this approach. Avista Corporation–Washington, Avista Corporation–Idaho, and Hydro Quebec use this approach for allocating all demand-related distribution plant in service and associated O&M costs.
- **Average of Loads During Select Periods –** One utility uses this approach. Seattle City Light takes marginal dollar per kW operating and annualized capital costs for distribution substations and lines for each rate schedule and multiplies them by class contributions to the highest average system MW load in 48 costing periods during the year to calculate marginal costs for each rate schedule.
- **Connected Load –** One utility uses this approach. Seattle City Light takes annualized dollar per kW marginal transformer costs for each rate schedule multiplied by connected load (sum of non-coincident peaks of customers) of each class to determine allocated marginal transformer costs.
- **Feeder 12 NCPs and Miles –** One utility uses this approach. Puget Sound Energy uses its customer and distribution feeder databases to associate each customer with a feeder. Monthly NCP load factors are then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peak on the feeder. Each class's contribution to monthly peak load on the feeder is multiplied by the number of overhead and underground miles on the feeder. These load-weighted line

miles are then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for overhead and underground lines are then developed by dividing the total load weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocation factors are applied to costs for overhead lines and the underground allocation factors are applied to costs for underground lines.

- **Substation 12 NCPs –** One utility uses this approach. Puget Sound Energy first determines each class's contribution to the peaks of individual distribution substations, as a percent of those peaks, by using the average hourly consumption of each class's load on the substation, divided by the NCP load factor of that class in that month. Each class's contribution to the peak load on each individual substation is then averaged across the months of the year. This average monthly contribution to each substation's peak load is then multiplied by the booked cost of the individual substation to derive the allocated cost of each substation. These allocated substation costs are then summed by customer class and compared with Puget Sound Energy's total substation investment to develop the substation cost allocations.

The approaches used by the surveyed utilities for allocation of customer-related and meter-related distribution plant in service and associated O&M costs are summarized below:

- **Book Value –** One utility uses this approach. Puget Sound Energy allocates customer-related distribution plant in service costs associated with meters based on the meter book values per class.
- **Blended Number of Bills/Revenue –** One utility uses this approach. BC Hydro uses this approach for allocating customer care O&M costs classified as customer-related. The blended allocator is 90 percent based on the percentage of bills by rate class and 10 percent based on the percentage of forecast revenues by rate class.
- **Direct to Customer Classes/Number of Services –** One utility uses this approach. Puget Sound Energy allocates customer-related distribution plant in service costs associated with underground services directly to the residential class. Overhead services are allocated to customer classes based on number of overhead services provided per class.
- **Number of Weighted Customers –** Using this approach, costs are allocated based on the weighted number of customers in a class versus total number of weighted customers. The weightings represent varying levels of effort or investment for different rate classes.

  Nine utilities use this approach as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to allocate customer-related distribution plant in service and O&M costs associated with meters.

    - Hydro-Québec Distribution and Newfoundland Power use this approach to allocate customer-related distribution plant in service and O&M costs associated with line transformers, service drops, and meters.
    - Idaho Power – Idaho and Manitoba Hydro use this approach to allocate customer-related distribution plant in service and O&M costs associated with service drops and meters.
    - Newfoundland Power uses this approach to allocate customer-related distribution plant in service costs associated with lines, transformers, services, and meters based on weighted number of customers.
    - Portland General uses this approach to allocate customer-related distribution plant in service and O&M costs associated with transformers, service drops, and meters.
    - Seattle City Light uses this approach to allocate customer-related distribution plant in service and O&M costs associated with meters.

- **Number of Weighted Meters –** One utility uses this approach. Seattle City Light calculates marginal meter costs by customer class by taking annual per meter O&M cost plus annualized capital costs per meter for each customer class and multiplying by number of meters in each class.
- **Number of Unweighted Customers –** Using this approach, costs are allocated based on the percentage of customers in each class.

  Five utilities use this approach as follows:

    - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to allocate customer-related costs associated with services drops.
    - BC Hydro uses this approach to allocate customer-related distribution O&M costs.
    - Hydro-Québec Distribution uses this approach to allocate customer-related lines plant in service costs and related O&M costs.
    - Idaho Power Company uses this to approach to allocate customer-related lines and transformers plant in service costs and associated O&M costs.

Also, the two utilities that use primarily a marginal COS approach use a form of the Derived from Other Allocated Costs method to allocate embedded distribution costs in that costs are allocated using the percentages by class of marginal demand and/or customers.

Table C-1
Results of Jurisdictional Review
COS Methodologies for Hydro Resources

	Classification									Allocation Approach	
	Hydro Plant In Service Costs			Hydro O&M Costs			Hydro Water Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	42%	58%	Hydro Peak Credit (3)	42%	58%	Hydro Peak Credit (3)	0%	100%	Energy Only	12 CP (4)	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na (5)	na	na	na (5)	na	na	na (5)	na	na (5)
Idaho Power	46%	54%	System Load Factor	44%	56%	System Load Factor/Energy Only (6)	46%	54%	System Load Factor	12 CP	Weighted Annual Energy at Generation (7)
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (8)
Newfoundland Power	46%	54%	System Load Factor (9)	46%	54%	System Load Factor (9)	46%	54%	System Load Factor (9)	1 CP	Annual Energy at Generation
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy (10)	35%	65%	Generation Marginal Costs - Demand & Energy (10)	4 CP (10)	Weighted Annual Energy at Generation (10)
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods (11)	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only (12)	0%	100%	Generation Marginal Costs - Energy Only (12)	na	Weighted Annual Energy at Generation (12)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior traditional Peak Credit method in the cost of service study.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(6) Idaho Power uses the System Load Factor method to classify all hydro plant in service and O&M accounts except non-labor electric operation expenses and electric plant maintenance expenses. Hydro non-labor electric operation expenses and electric plant maintenance expenses as energy related. Idaho Power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(7) Allocators are derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study

(8) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Company's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(9) Classification is based the system load factor taken from Newfoundland and Labrador Hydro's COS for 2007 Forecast Test Year for Island Interconnected.

(10) Portland General separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs. The 4 CP method, including the months January, July, August, and September, is used to allocate marginal capacity costs. To allocate marginal energy costs, Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(11) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(12) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-2
Results of Jurisdictional Review
COS Methodologies for Non-Peaking Thermal Resources

	Classification									Allocation Approach	
	Non-Peaking Thermal Plant In Service Costs			Non-Peaking Thermal O&M Costs			Non-Peaking Thermal Fuel Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	42%	58%	Thermal Peak Credit (3)	42%	58%	Thermal Peak Credit (3)	0%	100%	Energy Only	12 CP (4)	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na (5)	na	na	na (5)	na	na	na (5)	na	na (5)
Idaho Power	46%	54%	System Load Factor	28%	72%	System Load Factor/Energy Only (6)	0%	100%	Energy Only	12 CP	Weighted Annual Energy at Generation (7)
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (8)
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy (9)	35%	65%	Generation Marginal Costs - Demand & Energy (9)	4 CP (10)	Weighted Annual Energy at Generation (11)
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During 75 Peak Hours (12)	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only (13)	0%	100%	Generation Marginal Costs - Energy Only (13)	na	Weighted Annual Energy at Generation (14)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior traditional Peak Credit method in the cost of service study.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(6) Idaho Power uses the System Load Factor method to classify all non-peaking thermal plant in service and O&M accounts except non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses that are classified direct to energy. Idaho Power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(7) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(8) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, Manitoba Hydro's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(9) Portland General Electric Company separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(10) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(11) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(12) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(13) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-3
Results of Jurisdictional Review
COS Methodologies for Peaking Thermal Resources

	Classification									Allocation Approach	
	Peaking Thermal Plant In Service Costs			Peaking Thermal O&M Costs			Peaking Thermal Fuel Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	0%	100%	Energy Only	12 CP (3)	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na (4)	na	na	na (4)	na	na	na (4)	na	na (4)
Idaho Power	100%	0%	Demand Only	85%	15%	Demand Only/Energy Only (5)	0%	100%	Energy Only	3 CP	Weighted Annual Energy at Generation (6)
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (7)
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy (8)(4)	35%	65%	Generation Marginal Costs - Demand & Energy (8)	4 CP (9)	Weighted Annual Energy at Generation (10)
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods (11)	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only (12)	0%	100%	Generation Marginal Costs - Energy Only (12)	na	Weighted Annual Energy at Generation (13)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(4) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(5) All O&M expenses are classified direct to demand except non-labor generating operation and non-labor generating and electric plant maintenance expenses direct to energy. Idaho power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(6) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(7) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Manitoba Hydro's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(8) Portland General separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(9) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(10) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs, using percentages by class of total marginal capacity and energy costs.

(11) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(12) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(13) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-4
Results of Jurisdictional Review
COS Methodologies for Purchased Power Costs

	Classification Approach			Allocation Approach	
Utility	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	48%	52%	Derived from Classified Plant Costs (3)(1)	12 CP (4)	Annual Energy at Generation
Bonneville Power Administration	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution					
Heritage Resources (5)	34%	66%	System Load Factor (5)(6)	Relationship of Class to System Load Factors (7)(6)	Annual Energy at Generation (8)
Non-Heritage Resources	0%	100%	Energy Only (9)	na	Weighted Annual Energy at Generation (10)
Idaho Power	46%	54%	System Load Factor (11)	12 CP	Weighted Annual Energy at Generation (12)
Manitoba Hydro	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (13)
Newfoundland Power	30%	70%	Supplier COS Results (14)	1 CP	Annual Energy at Generation
Portland General	35%	65%	Generation Marginal Costs - Demand & Energy (15)	4 CP (16)	Weighted Annual Energy at Generation (17)
Puget Sound Energy	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods (18)	Annual Energy at Generation
Seattle City Light	0%	100%	Generation Marginal Costs - Energy Only (19)	na	Weighted Annual Energy at Generation (20)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric

system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Based on total classified gross generation plant in service.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided into three major divisions (Hydro-Québec Production, Hydro-Québec TransÉnergie , and Hydro-Québec Distribution). Hydro-Québec Production supplies Hydro-Québec Distribution with power from heritage resources. Bill 116, enacted in June 2000, introduced the concept of "heritage pool electricity" which is dedicated supply reserved for Quebec markets. The embedded cost of the supply of heritage pool electricity (from the production division to the distribution division) is fixed by law, for a maximum of 165 TWh/year at 2,79 ¢/kWh, which includes the energy and demand components. From year 2014 and for the following ones, this cost will be annually indexed at the inflation rate. It is to note that from year 2014 and the following ones, the industrial consumers will be exempted from the increase of the 2.79 ¢/kWh.

(6) System load factor, or utilization factor, is equal to system average annual MW divided by system peak MW within a defined 300-hour peak period. Using the system load factor, the 2.79 ¢/kWh cost of heritage pool electricity is classified as 65.6% energy related (1.83 ¢/kWh) and 34% demand related (0.96 ¢/kWh).

(7) Based on the relationship between specific load factor (i.e., utilization factor), of each class of consumers and the total distribution load factor (i.e., utilization factor). A class load factor, or utilization factor, is equal to the class average annual MW divided by the class non-coincident peak MW within a defined 300-hour peak period. For example, assuming a class load factor of 48.0%, class power losses of 9%, and system power losses of 8%, and heritage pool demand-related costs of 0.96 ¢/kWh, the allocated cost to the class would be 0.96 ¢/kWh X 65.6%/48.0% X (1+9%)/(1+8%) = 1.32 ¢/kWh. This cost would then be multiplied by class annual energy consumption with appropriate adjustments for losses.

(8) Energy-related heritage pool costs on a cents per kWh basis multiplied by class annual energy consumption with appropriate adjustments for losses.

(9) The cost of electric power over the heritage pool electricity is determined by way of a tender solicitation governed by procedure and a code of ethics submitted to the Régie's approval. It can include hydro-electric energy, thermal, wind power and biomass.

(10) The allocation to customers is called the "hourly method" and consists of (1) the establishment of an hourly weighted-cost for all the different supply contracts on the basis of their duration during the year and (2) the attribution of those costs on the basis of the hourly consumption for each customer class.

(11) Purchased power expenses booked to FERC Account 555 are classified as demand-and energy-related in the same manner as steam and hydro generation plant in service with the reasoning being that if the Company had chosen to build and operate a power plant to serve the same customer loads served by purchased power, the plant in service would have been classified as both demand and energy.

(12) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(13) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Company's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(14) Based on results, before deficit allocation, of Newfoundland and Labrador Hydro cost of service results for 2007 forecast test year. Newfoundland & Labrador Hydro used system load factor to classify hydro resources and associated transmission resources and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power were classified as demand-related and allocated based on 1 CP.

(15) Portland General Electric Company separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(16) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(17) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs, using percentages by class of total marginal capacity and energy costs.

(18) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(19) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(20) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-5
Results of Jurisdictional Review
COS Methodologies for Net Income from Wholesale Power Sales

		Classification Approach				Allocation Approach		
Utility	Recognized as Separate Class	Demand %	Energy %	Revenue %	Approach	Demand Related	Energy Related	Revenue Related
Avista Corporation - Washington	No	34%	66%	0%	System Load Factor	12 CP	Annual Energy at Generation	na
Avista Corporation - Idaho	No	48%	52%	0%	Derived from Classified Plant Costs (1)	12 CP	Annual Energy at Generation	na
Bonneville Power Administration	na	0%	100%	0%	Energy Only	na	Annual Energy at Generation (aMW)	na
Hydro-Québec Distribution	na	na	na	0%	na	na	na	na
Idaho Power Company	No	0%	100%	0%	Energy Only	na	Weighted Annual Energy at Generation (2)	na
Manitoba Hydro	Yes (3)	na	na	0%	na	na	na	na
Newfoundland Power	na	na	na	0%	na	na	na	na
Portland General	na	na	na	0%	na	na	na	na
Puget Sound Energy	Yes (4)	na	na	0%	na	na	na	na
Seattle City Light	No	na (6)	na (6)	100%	Generation Marginal Costs - Revenue Only (5)	na	na	Derived from Marginal Allocated Revenue Requirement (5)

(1) Based on total classified gross generation plant in service.

(2) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(3) Manitoba Hydro recognizes Export Sales as a separate class in their COS study. Additionally, the COS study differentiates between Dependable and Opportunity export sales. Dependable export sales have been assigned a share of embedded generation and transmission costs as done previously; Opportunity exports have been assigned the costs of purchased power excluding wind purchases, with remaining opportunity sales in excess of power purchases attracting water rentals fees and variable hydraulic generation O&M only.

(4) Puget Sound energy recognizes their Resale Class as a separate class in their COS study.

(5) Seattle City Light's net wholesale revenue offset is apportioned among all customer classes on the basis of the shares of the revenue requirements allocated by marginal cost shares.

Table C-6
Results of Jurisdictional Review
COS Methodologies for Transmission Resources

	Classification						Allocation Approach	
	Transmission Plant In Service Costs			Transmission O&M Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 CP (3)	na
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution								
Generation Related	na	na	na (4)	43%	57%	Transmission Division's Classified Rev Reqmt(5)	1 CP	Annual Energy at Generation
Interconnections w/ Neighboring Systems	na	na	na (4)	43%	57%	Transmission Division's Classified Rev Reqmt(5)	1 CP	Annual Energy at Generation
Network	na	na	na (4)	100%	0%	Demand Only	1 CP	na
Customer Connections	na	na	na (4)	100%	0%	Demand Only	1 NCP	na
Idaho Power	100%	0%	Demand Only	100%	0%	Demand Only	Weighted 12 CP (6)	na
Manitoba Hydro (7)								
Transmission	100%	0%	Demand Only	100%	0%	Demand Only	Ave of Loads During Select Peak Periods (8)	na
Subtransmission	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	100%	0%	Demand Only(9)	4 CP (10)	na
Puget Sound Energy (11)	19%	81%	Thermal Peak Credit (12)	19%	81%	Thermal Peak Credit (12)	Ave of Loads During Select Peak Periods (13)	Annual Energy at Generation
Seattle City Light								
Transmission In Service Area	na	na	na	100%	0%	Transmission Marginal Costs - Demand Only (14)	Ave of Loads During Peak Costing Period (15)	na
Long-Distance Transmission Services	na	na	na	0%	100%	Transmission Marginal Costs - Energy Only (16)	na	Annual Energy at Generation (aMW) (17)

(1) Avista Corporation - Washington indicated that in prior rate cases, transmission costs were assigned to energy and demand by a 50/50 weighting of the Thermal and Hydro Peak Credit ratios. However, in this rate case they are using a System Load Factor method to classify transmission. Reportedly in Washington, transmission costs have traditionally been treated as an extension of the generation system, therefore, the revised Peak Credit ratio was also been applied to transmission costs in their study. Avista identified several benefits to the system load factor approach for identifying the demand-related proportion of production costs: (1) It is simple and straightforward to calculate, (2) it is directly related to the system and test year under evaluation, and (3) the relationship should remain relatively stable from year to year.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated the use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season and it aligns with FERC Open Access transmission cost methodology.

(4) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any transmission plant in its assets.

(5) Transmission costs are classified by prorating them based on the classification results in Hydro Quebec TransÉnergie's request to change rates and conditions of transmission services for the test year 2012.

(6) Idaho Power uses the 12 CP method weighted for marginal costs.

(7) Manitoba Hydro defines transmission facilities to include only transmission lines which would be recognized for inclusion in their Open Access Transmission Tariff. Radial/non-grid transmission facilities (voltage greater than 100 kV and lower 66 kV and 33 kV) are included in the Subtransmission function. Subtransmission is classified as 100% demand related and allocated based on NCP.

(8) Manitoba Hydro utilizes a summer and winter coincident demand peak allocator based upon the average of the highest 50 peak hours in each season, adjusted for losses, for transmission facilities larger than 100 kV. Peak loads on the transmission system are approximately equivalent in magnitude in both seasons. High winter loads are caused by domestic retail space heating, while summer loads can be comparatively high because of export sales.

(9) Marginal transmission costs are not developed. Embedded transmission costs are classified 100 percent to demand.

(10) The 4 CP method, including the months January, July, August, and September, is used to allocate demand-related transmission costs.

(11) Includes costs for wheeling by others.

(12) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(13) Seattle City Light calculates marginal transmission costs based on historical three-year annual average transmission O&M costs adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these costs are subsequently allocated, they can be considered demand-related.

(14) For the last several rate reviews, estimates of projected consumption for aggregations of the hourly data were used (four costing periods each month or 48 per year) with the expectation that statistical errors in individual hours would, on average, balance out in the forecast periods. The total energy estimated for each period is then divided by the number of hours in the period to estimate the expected average hourly consumption. The coincident peaks for classes as total groups are then determined for the costing period with the largest hourly average consumption. Class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate costs.

(15) Seattle City Light calculates marginal costs for long-distance transmission services as BPA monthly transmission service price on a $/MW basis multiplied by estimated peak system load multiplied by 12. Based on the approach used to subsequently allocate these costs, they can be considered energy-related.

(16) Seattle City Light uses class contribution percentages to average annual system demand for allocating long-distance transmission service costs. Embedded costs for long-distance transmission services are allocated using class percentages of allocated marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-7
Results of Jurisdictional Review
COS Methodologies for Distribution Substations

	Classification						Allocation Approach	
	Distribution Substation Plant In Service Costs			Distribution Substation O&M Costs				
Utility	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Idaho Power	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Manitoba Hydro	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Portland General	na	na	na	100%	0%	Dist Substation Marginal Costs - Demand Only (2)	1 NCP (3)	na
Puget Sound Energy	100%	0%	Demand Only	100%	0%	Demand Only	Substation 12 NCPs (4)	na
Seattle City Light	na	na	na	100%	0%	Dist Substation Marginal Costs - Demand Only (5)	Ave of Peak Loads During Select Periods (6)	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Marginal $/kW costs were calculated by annualizing the sum of growth-related substation capital expenditures over projected 5-year period and dividing by the growth in system NCP.

(3) Marginal costs allocated to each rate schedule by multiplying marginal subtransmission cost $/kW multiplied by class NCP.

(4) For each month, each customer class's contribution to the peaks of individual distribution substations, as a percent of those peaks, is calculated using the average hourly consumption of each class's load on the substation, divided by the NCP load factor of that class in that month. Each class's contribution to the peak load on each individual substation is then averaged across the months of the year. This average monthly contribution to each substation's peak load is then multiplied by the booked cost of the individual substation in 2010 dollars to derive the allocated cost of each substation. These allocated substation costs are then summed by customer class and compared with PSE's total substation investment in 2010 dollars to develop the substation cost allocations for FERC Accounts 360-362.

(5) Marginal O&M costs are calculated as most recent historical annual O&M costs on a $/MW of total substation capacity basis, adjusted to represent costs for servicing a new marginal substation and for inflation, and then multiplied by total system substation capacity. Marginal annualized capital costs are calculated as annualized substation capital replacement cost on a $/MW of total substation capacity basis multiplied by total system substation capacity.

(6) Class contribution percentages to highest average system MW load in 48 costing periods during year.

Table C-8
Results of Jurisdictional Review
COS Methodologies for Distribution Lines

	Classification						Allocation Approach	
	Distribution Lines Plant In Service Costs			Distribution Lines, Poles, Towers, and Fixtures O&M Costs				
Utility	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	79%	21%	Minimum System Study (2)	79%	21%	Minimum System Study (2)	12 NCP	Number of Unweighted Customers
Idaho Power	64%	36%	Computation Method (3)	64%	36%	Computation Method (3)	1 NCP	Number of Unweighted Customers
Manitoba Hydro	60%	40%	Historic Study (4)	60%	40%	Historic Study (4)	1 NCP	Number of Unweighted Customers
Newfoundland Power	64%	36%	Minimum System Study	64%	36%	Minimum System Study	1 NCP	Number of Unweighted Customers
Portland General	na	na	na	100%	0%	Distribution Lines Marginal Costs - Demand Only (5)	1 NCP (6)	na
Puget Sound Energy	100%	0%	Demand Only	100%	0%	Demand Only	Feeder 12 NCPs and Miles (7)	na
Seattle City Light	na	na	na	100%	0%	Distribution Lines Marginal Costs - Demand Only (8)	Ave of Peak Loads During Select Peak Periods (9)	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (i) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) The Minimum System Study was filed with the Regie in 2004. The classification between demand and customer is updated each year.

(3) Fixed and variable ratio computation method used in prior rate cases. Updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.

(4) The proportions classified to demand and customer based upon a 1990 study by Ernst & Young and accepted for use by Manitoba Hydro since 1991. Manitoba Hydro will rely on a 70/30 split of primary and secondary voltage in their PCOSS13.

(5) Marginal costs are calculated using the following steps: (1) calculate replacement costs of distribution feeders, (2) for each feeder, allocate cost responsibility based on rate schedule's proportionate contribution to NCP, (3) calculate $/kW cost by totaling the cost responsibilities for all feeders and dividing by the sum of each schedule's NCP, (4) and annualize costs by applying an economic carrying charge.

(6) For each rate schedule, multiply average marginal feeder cost $/kW multiplied by class NCP.

(7) Puget Sound Energy uses its customer and distribution feeder databases to associate each customer with a feeder. Monthly NCP load factors are then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peak on the feeder. Each class's contribution to monthly peak load on the feeder is multiplied by the number of overhead and underground miles on the feeder. These load-weighted line miles are then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for

overhead and underground lines are then developed by dividing the total load weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocators are applied to FERC Accounts 364 and 365, and the underground allocators are applied to FERC Accounts 366 and 367.

(8) Marginal O&M costs are calculated as the historical three-year annual average wires O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace wires and related equipment.

(9) Class contribution percentages to highest average system MW load in 48 costing periods during year.

Table C-9
Results of Jurisdictional Review
COS Methodologies for Distribution Transformers

	Classification						Allocation Approach	
	Distribution Transformers Plant In Service Costs			Distribution Transformers O&M Costs				
Utility	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington [1]	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers [2]
Idaho Power	64%	36%	Computation Method [3]	64%	36%	Computation Method [3]	1 NCP	Number of Unweighted Customers
Manitoba Hydro	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	73%	27%	Zero Intercept Analysis	73%	27%	Zero Intercept Analysis	1 NCP	Number of Weighted Customers [2]
Portland General	na	na	na	0%	100%	Distribution Transformer Marginal Costs - Customer Only [4]	na	Number of Weighted Customers [5]
Puget Sound Energy	na	100%	Customer Only	na	100%	Customer Only	na	Direct to Customer Classes [6]
Seattle City Light	na	na	na	100%	0%	Distribution Transformer Marginal Costs - Demand Only [7]	Connected Load	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Number of customers, weighted for the specific cost of line transformers per class.

(3) Fixed and variable ratio computation method used in prior rate cases. Updated according to a system capacity utilization measurement based on a three-year average load duration curve.

(4) Marginal transformer costs are calculated by estimating the cost $/customer of providing the average customer a transformer.

(5) For each rate schedule, Portland General multiplies average marginal transformer costs $/customer by number of customers.

(6) Determines current costs, including installation, for transformers on system and directly assigns to classes if possible with remaining transformers allocated to each class based upon the class's relative contribution to embedded line transformer costs.

(7) Marginal annual transformer O&M cost per kW of load is calculated using an assumed factor for O&M as a % of annual capital cost for each customer class and then multiplied by the connected load (sum of noncoincident peaks of customers) of each class. Annualized capital costs are calculated as annualized cost to replace transformers per kW of load by customer class multiplied by connected load (sum of noncoincident peaks of customers) of each class.

Table C-10
Results of Jurisdictional Review
COS Methodologies of Distribution Services

	Classification			Allocation Approach	
	Distribution Services Plant In Service Costs				
Utility	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	0%	100%	Customer Only	na	Number of Unweighted Customers
Avista Corporation - Idaho	0%	100%	Customer Only	na	Number of Unweighted Customers
Bonneville Power Administration	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	na	Number of Weighted Customers
Idaho Power	0%	100%	Customer Only	na	Number of Weighted Customers
Manitoba Hydro	0%	100%	Customer Only	na	Number of Weighted Customers
Newfoundland Power	0%	100%	Customer Only	na	Number of Weighted Customers
Portland General	na	na	Dist Services Marginal Costs - Customer Only	na	Number of Unweighted Customers
Puget Sound Energy	na	100%	Customer Only	na	Direct to Customer Classes/No. of Services (2)
Seattle City Light	na	na	Dist Services Marginal Costs - Demand Only	100%	Ave of Peak Loads During Select Periods (6)

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Underground services are allocated direct to residential class. Overhead services are allocated to customer classes based on number of overhead services per class.

Table C-11
Results of Jurisdictional Review
COS Methodologies for Distribution Meters

	Classification			Classification			Allocation Approach	
	Distribution Meters Plant In Service Costs			Distribution Meters O&M				
Utility	Demand %	Customer %	Approach	Demand %	Customer/Meter %	Approach	Demand Related	Customer/Meter Related
Avista Corporation - Washington (1)	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Avista Corporation - Idaho	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Idaho Power	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Manitoba Hydro	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Newfoundland Power	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Portland General	na	na	na	0%	100%	Distribution Meter Marginal Costs - Customer Only (2)	na	Number of Weighted Customers (3)
Puget Sound Energy	na	100%	Customer Only	na	100%	Customer Only	na	Book Value (4)
Seattle City Light	na	na	na	0%	100%	Distribution Meter Marginal Costs - Customer Only (5)	na	Number of Weighted Meters (6)

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Marginal meter costs are calculated as the installed cost $/customer of a new AMI meter for each rate schedule multiplied by a carrying charge.

(3) For each rate schedule, Portland General multiplies the average marginal meter cost $/customer by number of customers.

(4) Based on book value by class.

(5) Marginal meter O&M costs per meter are calculated as the annual per meter O&M cost by customer class. Annualized marginal capital costs per meter are calculated as the annualized per meter cost to replace meters by customer class.

(6) For each rate schedule, Seattle City Light multiplies the average marginal meter cost $/customer by number of customers.

Table C-12
Results of Jurisdictional Review
COS Methodologies for DSM, Energy Efficiency, Conservation Assets and Costs

		Functionalization Approach					Classification Approach				Allocation Approach	
Utility	Type	Generation %	Transmission %	Distribution %	Customer Care %	Approach	Demand %	Energy %	Customer %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	na	na	na	na	na	na	na	na	na	na	na	na
Avista Corporation - Idaho	Amortization of Weatherization and DSM Investment	100%	0%	0%	0%	Generation Only	48%	52%	0%	Derived from Classified Plant Costs (1)	12 CP (2)	Annual Energy at Generation
Bonneville Power Administration	Conservation and Energy Efficiency Costs	100%	0%	0%	0%	Generation Only	0%	100%	0%	Energy Only	na	Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na	na	na	na	na	na	0%	na	na	na
Idaho Power Company	Customer Assistance for Energy Efficiency Programs	100%	0%	0%	0%	Generation Only	46%	54%	0%	System Load Factor	12 CP	Weighted Annual Energy at Generation (3)
Idaho Power Company	Demand Response Incentive Payments	100%	0%	0%	0%	Generation Only	100%	0%	0%	Demand Only	3 CP (summer)	na
Manitoba Hydro	na	na	na	na	na	na	na	na	0%	na	na	na
Newfoundland Power	Conservation and DSM General Costs	13%	10%	59%	18%	Derived from Other Functionalized O&M Costs (4)	49%	6%	45%	Derived from Other Classified O&M Costs (4)	Derived from Other Demand-Related Allocated O&M Costs (4)	Derived from Other Energy -Related Allocated O&M Costs (4)
Newfoundland Power	Costs to Develop Measurement Programs	97%	3%	0%	0%	Supply Cost Savings (5)	5%	95%	0%	Supply Cost Savings (5)	1 CP	Annual Energy at Generation
Newfoundland Power	Curtailable Service Option Costs (6)	95%	2%	4%	0%	Derived from Other Functionalized O&M Costs (6)	100%	0%	0%	Demand Only	Derived from Other Demand-Related Allocated O&M Costs (6)	na
Newfoundland Power	Demand Management Incentive Account (7)	100%	0%	0%	0%	Generation Only (7)	100%	0%	0%	Demand Only (7)	1 CP	na
Portland General	na	na	na	na	na	na	na	na	na	na	na	na
Puget Sound Energy	Weatherization Customer Assistance	100%	0%	0%	0%	Generation Only	19%	81%	0%	Thermal Peak Credit	Ave Loads During Select Peak Periods (8)	Annual Energy at Generation
Seattle City Light	Conservation O&M, Capital-Related, and Overhead Exp	100%	0%	0%	0%	Generation Only	0%	100%	0%	Marginal Costs (9)	na	Weighted Annual Energy at Generation (10)

(1) Based on total classified gross generation plant in service.

(2) Avista indicated that although they are usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(4) Conservation and demand management general costs are functionalized, classified, and allocated based on corporate administration and general expenses.

(5) Costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage are classified between demand and energy reflective of the supply cost savings which occurred in 2011 (95% to production energy, 2% to production demand, and 3% to substation demand).

(6) The functional classification of curtailable service option costs is based on direct O&M costs classified as related to demand. Allocation based on associated demand-related O&M costs.

(7) Transfers to the reserve stabilization fund associated with the demand management incentive are shown under purchased power expenses and classified 100% to demand.

(8) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year.

(9) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(10) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-13
Results of Jurisdictional Review
Target and Actual R/C Ratios Used for Proposed Rate Design

Utility	Approach for Setting R/C Ratios for Proposed Rates	Target R/C Ratios	Based on Existing Rates: Total System R/C Ratio	Based on Existing Rates: Range of Class R/C Ratios	Based on Proposed Rates: Range of Class R/C Ratios
Avista Corporation - Washington	na (1)	na (1)	92%	81% - 119%	89% - 130%
Avista Corporation - Idaho	COS Results as a Guide (2)	na (2)	96%	86% - 107%	90% - 111%
Bonneville Power Administration	Dictated by Law (3)	100% (3)	na	na	100% (3)
Hydro-Québec Distribution	na (4)	na (4)	na	na	83% - 134%
Idaho Power	Limits on Rate Increases and Decreases (5)	100% (5)	92%	57 % - 216%	66% - 216%
Manitoba Hydro	Target Range of R/C Ratios/Across-the-Board Rate Changes (6)	95% - 105%	100% (7)	89% - 108%	94% - 114% (8)
Newfoundland Power	Target Range of R/C Ratios (9)	90% - 110%	100% (7)	95% - 113%	96% - 110%
Portland General	Caps on Rate Increases (10)	100%	92%	41% - 106%	48% - 104%
Puget Sound Energy	Mutiple Guidelines (11)	95% - 105%	92%	81% -98% (12)	93% - 105 (12)
Seattle City Light	Set by City Council Resolutions (13)	100%	96%	79% - 103%	100% (13)

(1) Avista Corporation - Washington proposed across-the-board increases.

(2) Avista Corporation – Idaho only indicated that they used COS results as "guide" to spreading overall revenue increases to rate schedules.

(3) The entire process used by BPA to allocate costs to customer classes and then design rates is largely dictated by the Northwest Power Act. The process includes the following steps: (i) COS analysis in which various types of costs are allocated to the various classes, or rate pools, of customers using allocation factors calculated based on loads and resources, ii) a rate directives step in which costs are reallocated between rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the law., and (iii) the final rate design step that produces the final rates.

(4) Hydro-Québec Distribution indicated that since 2004 uniform increases have been applied. Also, by law, they cannot deliberately modify the R/C ratio of 0.83 for their residential class.

(5) In Idaho Power's most recent rate filing, target revenues for rate design were established based on the following: (i) no decrease for any rate class, (ii) cap any class rate increases at 1.5 times the system average rate increase, and (iii) reallocate any shortfall in revenue collection created by capping increases to classes receiving uncapped revenues. Idaho Power's ratemaking proposals general advocate movement towards cost of service results, but other objectives such as rate stability are considered.

(6) Manitoba Hydro's rate design objectives include a long-term target to have all class R/C ratios in the range of 95 percent to 105 percent with all classes being gradually moved toward R/C ratios of unity. In conformity with the principles of gradualism and sensitivity to customer impacts, Manitoba Hydro limits annual adjustments to revenues by customer class to less than two percentage points greater than the overall proposed increase.

(7) Manitoba Hydro and Newfoundland Power reported their RCC ratios based on current rates with a base of 100%.

(8) Estimated based on two proposed across-the-board increase of 2.5% and 3.5%.

(9) Newfoundland Power reports their RCC ratios based on current rates with a base of 100%. The Company's rate change plan proposes to (i) vary the rate increase by customer rate class so cost recovery for each class is within the target revenue to cost ratio range of 90% to 110%, and (ii) to implement changes in customer rate designs in accordance with the Retail Rate Review. The revenue to cost ratios for the small general service classes are greater than 110%. The Company's rate proposals in this Application were developed, in part, to bring the revenue to cost ratios for those classes with R/C ratios above 100% within the target range. This indicates that a higher than average or average increase will be required for the other classes.

(10) Portland General proposed to move rate classes to an R/C ratio of 1.0 with a maximum increase of 17 percent for any class.

(11) Based upon the parity percentages shown in Puget Sound Energy's COS results and the goal to move towards full parity (a parity percentage of 100 percent) in a gradual manner, they proposed the following in their last rate filing: (i) Apply, with two exceptions, an adjusted average rate increase to retail classes within 5% of full parity; (ii) Apply a rate increase that is 75% of the adjusted average to the class that is more than 5% above full parity; and (iii) Apply an increase that is 125% of the average to the one retail class that is 5% or more below full parity.

(12) Ranges shown are for retail classes only.

(13) Seattle City Light's rate design objectives are primarily set through Seattle City Council resolutions. An R/C ratio of 1.0 has long been recognized as a guideline. Deviations have been allowed if they would accomplish some other goal. It is recognized that in order to promote rate stability, deviations from the cost standard might be necessary. This was the case in every rate increase since the goal of cost-based rates was first proposed until their last rate case in 2006 that established rates for the two year period 2007-08. That rate case discontinued a “gradualism” policy that shifted some revenue requirements away from cost-of-service allocations in order to satisfy social policy concerns. Seattle City Light's most recent rate proposal continues cost-of-service based rates as the standard, with the only deviation being the reflection of franchise agreement provisions.

Appendix D
CLASSIFICATION METHODOLOGIES BY RESOURCE FROM JURISDICTIONAL REVIEW

The detailed results of the jurisdictional review regarding classification methodologies are discussed below for generation, transmission, and distribution resources.

Generation Classification Approaches

The classification approaches used for each type of generation resource cost, purchased power costs, and net income from wholesale power sales are shown in Tables C-1 through C-6 and Table C-12 in Appendix C and summarized below:

- **Hydro Generation Resources –** As shown in Table C-1, the following approaches are used to classify hydro generation resources:
  - **Energy Only –** Four utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Idaho uses this approach to classify hydro water costs. BPA classifies all hydro O&M expenses as energy-related, and Manitoba Hydro classifies all hydro plant in service and O&M expenses as energy-related. Idaho Power classifies only hydro non-labor electric operation expenses and electric plant maintenance expenses as energy-related.
  - **Generation Marginal Costs –** Two utilities use this approach for generation costs. Portland General and Seattle City Light use a marginal COS methodology by first developing marginal capacity, or demand, costs and/or marginal energy costs that are subsequently allocated to customer classes. Portland General calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs. The other utility, Seattle City Light, uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related. The embedded costs for hydro generation, as well as other types of generation, are then allocated by both utilities based on the percentages by class of total allocated marginal generation costs.
  - **Hydro and Thermal Peak Credit –** Two utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Idaho uses the Hydro Peak Credit method for hydro plant in service and associated O&M, excluding water costs, while Puget Sound Energy uses the Thermal Peak Credit method for all hydro plant in service and O&M costs.

    - **System Load Factor –** Three utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Washington and Newfoundland Power use this approach to classify all hydro plant in service and associated O&M costs. Idaho Power uses it to classify all hydro plant in service and O&M accounts except non-labor electric operation expenses and electric plant maintenance expenses.

- **Non-Peaking Thermal Generation Resources –** As shown in Table C-2, the following approaches are used to classify non-peaking thermal generation resources:
    - **Demand Only –** One utility, Newfoundland Power, classifies all non-peaking thermal generation plant in service costs and O&M costs, including fuel, as demand-related.
    - **Energy Only –** Four utilities use this approach for classifying non-peaking thermal generation resources. BPA classifies non-peaking thermal generation resources and O&M expenses as energy-related, and Manitoba Hydro classifies all non-peaking thermal generation plant in service and O&M costs, including fuel, as energy-related. Idaho Power classifies non-peaking thermal generation costs for fuel, non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses direct to energy. Avista Corporation–Idaho uses this approach to classify non-peaking thermal generation fuel.
    - **Marginal Costs –** The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for non-peaking thermal generation resources as hydro resources, as discussed above.
    - **System Load Factor –** Two utilities use this approach to classify non-peaking thermal generation plant in service costs and associated O&M costs. Avista Corporation–Washington uses this approach to classify all non-renewables plant in service and associated O&M costs including fuel. Idaho Power uses it to classify all baseload/thermal plant in service and O&M accounts except fuel, non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses that are classified direct to energy.
    - **Thermal Peak Credit –** Two utilities use this approach to classify non-peaking plant in service and associated O&M costs. Avista Corporation–Idaho uses the Thermal Peak Credit method for non-peaking plant in service and associated O&M, excluding fuel, while Puget Sound Energy uses a thermal peak credit approach for all non-renewables plant in service and O&M costs including fuel.

- **Peaking Thermal Generation Resources –** As shown in Table C-3, the following approaches are used to classify peaking thermal generation resources:
    - **Demand Only –** Three utilities use this approach to classify peaking thermal generation resources plant in service and associated O&M costs. Avista–Idaho uses this approach to classify peaking thermal generation plant in service and O&M costs, excluding fuel. Newfoundland Power uses this approach to classify peaking thermal generation resources plant in service and associated O&M costs, including fuel. Idaho Power uses this approach to classify peaking thermal generation plant in service and O&M expenses except fuel, non-labor generating operation, and non-labor generating and electric plant maintenance expenses.
    - **Energy Only –** Four utilities use this approach for peaking thermal generation resources. Avista–Idaho uses this approach to classify peaking thermal generation fuel. BPA classifies peaking thermal generation resources O&M costs, including fuel, as energy-related. Manitoba Hydro classifies all peaking thermal generation plant in service costs and O&M accounts, including fuel, as energy-related. Idaho Power uses this approach to classify peaking thermal generation fuel, non-labor generating operation, and non-labor generating and electric plant maintenance expenses.
    - **Generation Marginal Costs –** The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for classifying peaking thermal generation resources as hydro resources as discussed above.
    - **System Load Factor –** Only one utility, Avista Corporation–Washington, uses this approach to classify peaking thermal generation plant in service cost and associated O&M costs including fuel.
    - **Thermal Peak Credit –** One utility**,** Puget Sound Energy, uses this approach for all peaking thermal generation plant in service and O&M costs including fuel.
- **Purchased Power Costs –** As shown in Table C-4, the following approaches are used to classify purchased power costs:
    - **Derived from Classified Plant Costs** – One utility, Avista–Idaho, uses the demand/energy split for total classified generation plant in service to classify purchased power costs between demand and energy.
    - **Energy Only –** Two utilities, BPA and Manitoba Hydro, classify purchased power expenses as energy-related. In addition, Hydro-Québec Distribution classifies purchased power costs from non-Heritage resources as 100 percent energy-related.

- **Generation Marginal Costs –** The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for purchased power as hydro resources as discussed above.
- **Supplier COS Results** – One utility uses this approach. Newfoundland Power purchases the majority of their power from Newfoundland and Labrador Hydro. Newfoundland Power classifies purchased power based on Newfoundland and Labrador Hydro's classified cost to serve Newfoundland Power for the 2007 forecast test year. Newfoundland and Labrador Hydro use the System Load Factor method to classify hydro resources and associated transmission resources and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power are classified as demand-related and allocated based on 1 CP.
- **System Load Factor –** Three utilities, Avista Corporation–Washington, Hydro-Québec Distribution, and Idaho Power and use this approach to classify purchased power costs. This is the same approach Avista uses for all other generation plant in service and O&M costs. Idaho Power's purchased power expenses are also classified as demand-related and energy-related in the same manner as steam and hydro generation plant in service with the reasoning being that if Idaho Power had chosen to build and operate a power plant to serve the same customer loads served by purchased power, the plant would have been classified as both demand and energy. Hydro-Québec Distribution uses the System Load Factor Method, or utilization factor approach, to classify purchased power costs from heritage resources.[9]
- **Thermal Peak Credit –** One utility, Puget Sound Energy, uses this approach to classify purchased power costs.

- **Net Income from Wholesale Power Sales –** As shown in Table C-5, the following approaches are used to classify net income from wholesale power sales:
  - **Energy Only –** Two utilities, BPA and Idaho Power, use this approach to classify net income from wholesale power sales.
  - **Derived from Classified Plant Costs –** One utility, Avista Corporation–Idaho, uses this approach to classify net income from wholesale power sales based on classified gross generation plant in service in service.

[9] The utilization factor is equal to system average annual MW divided by system peak MW within a defined 300-hour peak period. Using the system load factor, the 2.79¢/kWh fixed cost of heritage pool electricity is classified as 65.6 percent energy-related (1.83¢/kWh) and 34 percent demand related (0.96 ¢/kWh).

- **Generation Marginal Costs – Revenue Only** – One utility uses this approach. Seattle City Light's net income from wholesale power sales is apportioned among all customer classes based on the shares of the revenue requirements allocated by marginal cost shares.
- **System Load Factor –** One utility, Avista Corporation–Washington, uses this approach to classify net income from wholesale power sales.

Transmission Classification Approaches

As shown in Table C-7 of Appendix C, the following approaches are used to classify transmission resource costs:

- **Demand Only** – Six utilities use this methodology:
  - Avista Corporation–Idaho, Portland General, and Newfoundland Power classify all transmission plant in service and associated O&M expenses as demand-related.
  - Manitoba Hydro classifies all transmission and subtransmission plant in service, and associated O&M costs, as demand-related.
  - Idaho Power classifies all transmission plant in service and associated O&M costs, with the exception of costs associated with wheeling by others, as demand-related as well.
  - Hydro Québec classifies network transmission costs and customer interconnection costs as 100 percent demand-related.
- **Energy Only** – Two utilities use this methodology:
  - Idaho Power classifies costs associated with wheeling by others as energy-related.
  - BPA classifies all transmission O&M costs as energy-related.
- **System Load Factor** – Two utilities use this methodology:
  - Avista Corporation–Washington uses this approach to allocate transmission plant in service and related O&M. Although Avista Corporation–Washington has traditionally applied the peak credit rating ratio to transmissions costs, the System Load Factor method was used to classify transmission plant in service and associated O&M costs in the most recent rate case.
  - Hydro-Québec Distribution classifies generation-related transmission costs and costs for interconnections with neighboring systems based on the load factor of Hydro-Québec Transmission Division (TransÉnergie).
- **Thermal Peak Credit** – One utility uses this methodology. Puget Sound Energy's uses this approach for classifying transmission plant in service and associated O&M costs. Peak credit percentages are applied to transmission

costs by Puget Sound Energy under the theory that transmission lines are constructed to deliver energy and capacity provided by generating plant, and in the same proportion as it is being provided.

- **Transmission Marginal Costs –** Using this approach, utilities (1) calculate marginal transmission demand-related and energy-related costs for a test year, thus identifying the demand-related and energy-related portions of marginal costs, (2) allocate the demand-related and energy-related components of marginal transmission costs to customer classes, and (3) allocate the embedded costs for transmission based on the percentages by class of total allocated marginal demand-related and energy-related costs.

  One utility, Seattle City Light, uses this approach and calculates marginal transmission costs as follows:

  - Costs for Transmission in Service Area: First, annualized costs for transmission service in Seattle City Light's service area are calculated. Historical three-year annual average transmission O&M costs are adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent demand-related.
  - Costs for Long-Distance Transmission Services: Seattle City Light calculates marginal costs for long-distance transmission service as BPA's monthly transmission service price on a dollar per MW basis multiplied by estimated peak system load multiplied by 12. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent energy-related.

Distribution Classification Approaches

The classification approaches used for each type of distribution resource cost are shown in Tables C-7 through C-12 in Appendix C and summarized below:

- **Distribution Substations –** As shown in Table C-7, the following approaches are used to classify plant in service and O&M costs associated with distribution substations:
  - **Demand Only –** Seven utilities use this approach to classify distribution substation plant in service and associated O&M costs. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro Québec Distribution, Idaho Power Company–Idaho, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.
  - **Transmission Substation Marginal Costs –** Two utilities use this approach to determine classified marginal distribution substation costs as follows:

    - Portland General treats marginal costs associated with substations as demand-related in their analyses. Portland General Electric calculates marginal dollar per kW substation costs by annualizing the sum of growth-related substation capital expenditures over projected 5-year period and dividing by the growth in system NCP. These dollar per kW marginal costs are subsequently multiplied by class NCPs to allocate marginal costs.
    - Seattle City Light treats marginal costs associated with substations as demand-related in their analyses. They calculate marginal substation O&M costs as the most recent historical annual O&M costs on a dollar per MW of total substation capacity basis, adjusted to represent costs for servicing a new marginal substation and for inflation, and then multiplied by total system substation capacity. Marginal annualized capital costs are calculated as annualized substation capital replacement cost on a $/MW of total substation capacity basis multiplied by total system substation capacity. These dollar per MW marginal costs are subsequently multiplied by class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate marginal costs.

- **Distribution Lines –** As shown in Table C-8, the following approaches are used to classify plant in service and O&M costs associated with distribution lines:
  - **Computation Method –** One utility uses this approach. Idaho Power Company–Idaho uses a fixed and variable ratio computation method used in prior rate cases. The computations are updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.
  - **Demand Only –** Three utilities use this approach. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, and Puget Sound Energy.
  - **Distribution Lines Marginal Costs –** Two utilities use this approach to determine classified marginal distribution costs associated with lines as follows:
    - Portland General treats marginal costs associated with lines as demand-related in their analyses. They calculate marginal distribution feeder costs using the following steps: (1) calculate replacement costs of distribution feeders, (2) for each feeder, allocate cost responsibility based on rate schedule's proportionate contribution to NCP, (3) calculate the dollar per kW cost by totaling the cost responsibilities for all feeders and dividing by the sum of each schedule's NCP, and (4) annualize

costs by applying an economic carrying charge. These dollar per kW marginal costs are subsequently multiplied by class NCPs to allocate marginal costs.

    - Seattle City Light treats marginal costs associated with lines (including service lines) as demand-related in their analyses. They calculate marginal O&M costs for lines as the historical three-year annual average lines O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace lines and related equipment. These costs are subsequently allocated based on class contribution percentages to average MW per hour in the costing period during the year with the maximum load.

  - **Historic Study –** One utility uses this approach. The proportions Manitoba Hydro classifies to demand and customer are based upon a 1990 study by Ernst & Young and accepted for use by Manitoba Hydro since 1991.

  - **Minimum System Study –** Two utilities use this approach. These utilities include Hydro Québec Distribution and Newfoundland Power.

- **Distribution Transformers –** As shown in Table C-9, the following approaches are used to classify plant in service and O&M costs associated with distribution transformers:

  - **Computation Method –** One utility uses this approach. Idaho Power Company uses a fixed and variable ratio computation method used in prior rate cases. The computations are updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.

  - **Customer Only –** Two utilities use this approach. These utilities are Hydro Québec Distribution and Puget Sound Energy.

  - **Demand Only –** Three utilities use this approach. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, and Manitoba Hydro.

  - **Distribution Transformer Marginal Costs –** Two utilities use this approach to determine classified marginal distribution costs associated with lines as follows:

    - Portland General treats marginal costs associated with transformers as customer-related in their analyses. Portland General Electric calculates transformer costs by estimating the cost dollar per customer of providing the average customer a transformer. These dollar per customer marginal costs are subsequently multiplied by number of customers to determine allocated marginal costs.

        - Seattle City Light treats marginal costs associated with transformers as demand-related in their analyses. They calculate marginal transformer O&M cost per kW of load using an assumed factor for O&M as a percentage of annual transformer capital cost for each customer class. Annualized capital costs area assumed to be equal to the costs to replace transformers per kW of load. The dollar per kW annualized capital and O&M costs by customer class are subsequently multiplied by connected loads (sum of non-coincident peaks of customers) by class to determine marginal costs by class.
    - **Zero Intercept Analysis –** One utility, Newfoundland Power, uses this approach.
- **Distribution Services –** As shown in Table C-10, the following approaches are used to classify plant in service costs associated with distribution service drops:
    - **Customer Only –** Seven utilities use this approach. These include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro Québec Distribution, Idaho Power, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.
    - **Distribution Services Marginal Costs –** Two utilities use this approach to determine classified marginal distribution costs associated with service lines as follows:
        - Portland General treats marginal costs associated with service drops as customer-related in their analyses. Portland General Electric calculates service line costs by estimating the cost dollar per customer of providing the average customer a service line. These dollar per customer marginal costs are subsequently multiplied by number of customers to determine allocated marginal costs.
        - Seattle City Light treats marginal costs associated wires including service lines as demand-related in their analyses. They calculate marginal O&M costs for wires as the historical three-year annual average wires O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace wires and related equipment. These costs are subsequently allocated based on class contribution percentages to average MW per hour in the costing period during the year with the maximum load.
- **Distribution Meters –** As shown in Table C-11, the following approaches are used to classify plant in service and O&M costs associated with distribution meters:
    - **Customer Only –** Seven utilities use this approach. These include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro

Québec Distribution, Idaho Power Company–Idaho, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.

- **Distribution Meters Marginal Costs –** Two utilities use this approach to determine classified marginal distribution costs associated with meters as follows:
  - Portland General treats marginal costs associated with meters as customer-related in their analyses. They calculate marginal meter costs as the installed cost on a dollar per customer basis of a new advanced metering infrastructure meter for each rate schedule multiplied by a carrying charge. For each rate schedule, Portland General subsequently multiplies the average marginal meter cost on a dollar per customer basis by number of customers to determine marginal meter costs by class.
  - Seattle City Light treats marginal costs associated meters as customer-related in their analyses. They calculate marginal meter O&M costs per meter as the annual per meter O&M cost by customer class. Annualized marginal capital costs per meter are calculated as the annualized per meter cost to replace meters by customer class. Total marginal costs by customer class are subsequently calculated by taking annual per meter O&M cost plus annualized capital costs per meter for each customer class and multiplying by number of meters in each class.

DSM, Energy Efficiency, and Conservation Classification Approaches

As shown in Table C-12 of Appendix C, the following approaches are used to classify costs associated with DSM, energy efficiency, and conservation programs:

- **Demand Only –** Two utilities use this approach. Idaho Power classifies DSM incentive payments as 100 percent demand-related. Newfoundland Power classifies curtailable service option costs and transfers to the reserve stabilization fund associated with the demand management incentive as 100 percent demand-related.
- **Derived from Classified Plant Costs** – One utility, Avista–Idaho, uses the demand/energy split for total classified generation plant in service to classify DSM investment in rate base and related amortization expense.
- **Derived from Other Classified O&M Costs –** One utility uses this approach. Newfoundland Power functionalizes, classifies and allocates conservation and demand management general costs based on corporate administration and general expenses.
- **Energy Only –** One utility uses this approach. BPA classifies conservation and energy efficiency costs as energy-related.

- **Generation Marginal Costs –**One utility uses this approach. Seattle City Light uses the same approach for conservation O&M, and associated capital-related and overhead–related costs as hydro resources as discussed above.
- **Supply Cost Savings –** One utility uses this approach. Newfoundland Power costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage are classified between demand and energy reflective of the supply cost savings which occurred in 2011 (95 percent to production energy, 2 percent to production demand, and 3 percent to substation demand).
- **System Load Factor –** One utility uses this approach. Idaho Power classifies customer assistance costs for energy efficiency programs using the System Load Factor method.
- **Thermal Peak Credit –** One utility, Puget Sound Energy, uses the Thermal Peak Credit method to classify DSM costs.