2015 RATE DESIGN APPLICATION (RDA): COST OF SERVICE (COS) METHODOLOGY REVIEW

BC hydro

FOR GENERATIONS

June 19, 2014

AGENDA

Approximate Time	Item	Presenter(s)
9 :00 – 9:10	Welcome	Anne Wilson
9:10 – 9:45	• Stakeholder comments and questions from the May 8, 2014 workshop • Background	Justin Miedema
9:45 – 10:30	Consultant report jurisdictional review	Richard Cuthbert
10:30 – 10:45	Break	Break
10:45 – 12:30	Consultant report recommendations and BC Hydro's proposals for modelling	Richard Cuthbert, Justin Miedema & Dani Ryan

This slide deck should be read in conjunction with BC Hydro's Strawman Proposal concerning the December 2013 Cost of Service Methodology Review

MAY 8th STAKEHOLDER COS COMMENTS

- During the workshop BC Hydro was asked to:
  - Consider the creation of an Independent Power Producer (IPP) class of customers for COS
  - Calculate Revenue to Cost (R/C) ratios for the Non-Integrated Area and Fort Nelson
  - Post prior Fully Allocated Cost of Service Studies (FACOS) filed with the British Columbia Utilities Commission (BCUC) since the 2007 RDA
- In addition, BC Hydro received written comments and questions on COS topics from BCUC staff and customer stakeholders
  - These will be addressed in a stakeholder feedback summary of the workshop, which will be posted on BC Hydro's RDA website

Marginal Vs. Embedded COS:

- BCUC staff recommended attempting to get consensus on this issue
- An embedded approach is consistent with historic practice.
- In the 2007 RDA, the BCUC found there has been no widespread adoption of marginal COS methods, and this continues to be the case
- Almost all Canadian and Pacific Northwest utilities use embedded approaches. In these jurisdictions, marginal costs are used to inform rate design rather than the allocation of embedded costs
- Stakeholders who commented as part of the written process after the May 8th workshop agreed with BC Hydro's suggestion to prepare an embedded COS. We will proceed on that basis

COST OF SERVICE METHODOLOGY

BACKGROUND

BC hydro
FOR GENERATIONS

June 19, 2014

FUNCTIONALIZING THE REVENUE REQUIREMENT

- Cost of Energy
- Operations, Maintenance and Administration (OMA)
- Depreciation
- Financing Charges
- Return on Equity (ROE)
- Taxes
- Regulatory Accounts
- Misc. revenue
- Subsidiary Net Income (Powerex / Powertech)

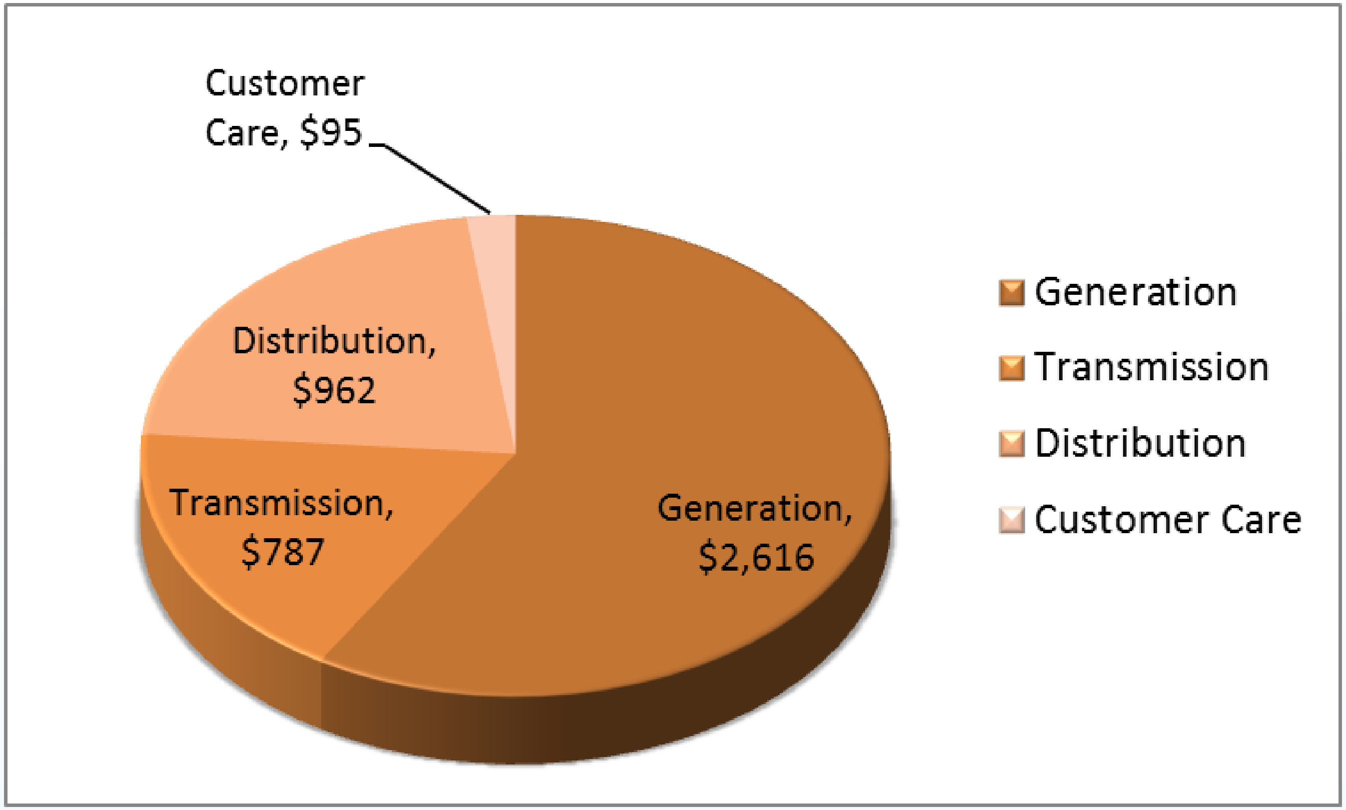
Capital related costs

CURRENT FUNCTIONALIZATION

Based on F2016 Plan	($million)	G	T	D	C
Cost of Energy	1,391	98%	2%	-	-
OMA	978	37%	28%	26%	9%
Capital Charges • Depreciation • Financing Charges • ROE	2,175	43%	29%	27%	1%
Taxes	224	21%	63%	13%	3%
Demand Side Management (DSM)	Costs are captured in the capital charges	90%	10%	-	-
Regulatory Account Recoveries	133	100%	-	-	-
Subsidiary Net Income (Powerex/ Powertech)	-115	100%	-	-	-
Corporate Costs (OMA, Depreciation, Taxes)	173	37%	31%	26%	7%

FUNCTIONALIZING THE REVENUE REQUIREMENT

Based on F2016 costs including recoveries from regulatory accounts ($million)



CURRENT CLASSIFICATION

Based on F2016 Plan		Comments
Generation	Hydroelectric Assets	45% energy / 55% demand
	Thermal Assets	100% demand-related
	OMA & capital costs	The weighted average of classification for BC Hydro's hydroelectric and thermal assets is applied (~43% energy / ~57% demand)
	IPPs	IPP costs are treated as 100% energy
	Cost of Energy	This is classified almost entirely to energy; however, about 10% of the water rental charge is based on the installed capacity of generating units. This component is classified to demand

BChydro
FOR GENERATIONS

CURRENT CLASSIFICATION

Based on F2016 Plan	Comments
Transmission	100% demand
Distribution	65% demand and 35% customer
Customer Care	Customer Care expenses (ex. call center, billing) would typically be considered 100% customer related. The BCUC directed BC Hydro to use 65% demand and 35% customer

CURRENT CLASSIFICATION

Based on F2016 Plan		($million)	Energy	Demand	Customer
Generation	Hydroelectric Assets	$1,336 for OMA, Depreciation, financing, taxes, ROE	45%	55%	-
	Thermal Assets		0%	100%	-
	IPPs	$975	100%	0%	-
	Cost of Energy	$390	98%	2%	
	Powerex Net Income	-$115	70%	30%	
Transmission		$787	0%	100%	-
Distribution		$962	-	65%	35%
Customer Care		$100	-	65%	35%

BC hydro FOR GENERATIONS

CURRENT ALLOCATORS

Functional area	Classification	Description
Generation	Energy portion	Pro-rata share of energy consumption
	Demand portion	4 coincident peak (CP) directed by BCUC in recognition of the winter peak's importance in system planning
Transmission	Demand portion	4 CP directed by BCUC in recognition of the winter peak's importance in system planning
Distribution	Demand portion	Non-coincident peak (NCP) of each rate class
	Customer portion	# of customers
Customer Care	Demand portion	NCP of each rate class
	Customer portion	90% of the allocation is weighted based on the number of customer bills while the remaining 10% is based on revenue from each class

BC hydro
FOR GENERATIONS

FOUR KEY ALLOCATORS

GENERATION ENERGY

Pro-rata share of energy consumption by rate class

<table>
<tr><th></th><th>F2008</th><th>F2013</th><th>Change</th></tr>
<tr><td>Residential</td><td>34%</td><td>36%</td><td>+2%</td></tr>
<tr><td>Small General Service (SGS)</td><td>8%</td><td>8%</td><td>-</td></tr>
<tr><td>Medium General Service (MGS)</td><td rowspan="2">27%
(> 35 kW Class)</td><td>7%</td><td rowspan="2">+2%</td></tr>
<tr><td>Large General Service (LGS)</td><td>22%</td></tr>
<tr><td>Irrigation</td><td>0%</td><td>0%</td><td>-</td></tr>
<tr><td>Street Lighting</td><td>0%</td><td>0%</td><td>-</td></tr>
<tr><td>Transmission</td><td>30%</td><td>27%</td><td>-3%</td></tr>
</table>

39% of Revenue Requirement costs are energy-related

FOUR KEY ALLOCATORS

GENERATION AND TRANSMISSION DEMAND

Average share of monthly peak load across the 4 winter months (4CP)

<table>
<tr><th></th><th>F2008</th><th>F2013</th><th>Change</th></tr>
<tr><td>Residential</td><td>44.6%</td><td>46.5%</td><td>+1.9%</td></tr>
<tr><td>SGS</td><td>7.6%</td><td>7.2%</td><td>-0.4%</td></tr>
<tr><td>MGS</td><td rowspan="2">25%
(> 35 kW Class)</td><td>6.6%</td><td rowspan="2">+2.2%</td></tr>
<tr><td>LGS</td><td>18.6%</td></tr>
<tr><td>Irrigation</td><td>0.0%</td><td>0.0%</td><td>-</td></tr>
<tr><td>Street Lighting</td><td>0.4%</td><td>0.7%</td><td>+0.3%</td></tr>
<tr><td>Transmission</td><td>22.4%</td><td>20.4%</td><td>-2%</td></tr>
</table>

33% of Revenue Requirement costs are G&T demand-related

FOUR KEY ALLOCATORS

DISTRIBUTION DEMAND

Share of demand as ratio of individual rate class peak to sum of all rate class peaks (NCP)

<table>
<tr><th></th><th>F2008</th><th>F2013</th><th>Change</th></tr>
<tr><td>Residential</td><td>55.3%</td><td>54.3%</td><td>-1%</td></tr>
<tr><td>SGS</td><td>10.7%</td><td>10.3%</td><td>-0.4%</td></tr>
<tr><td>MGS</td><td rowspan="2">32.9%
(>35 kW class)</td><td>9.1%</td><td rowspan="2">+1.3%</td></tr>
<tr><td>LGS</td><td>25.1%</td></tr>
<tr><td>Irrigation</td><td>0.4%</td><td>0.4%</td><td>-</td></tr>
<tr><td>Street Lighting</td><td>0.6%</td><td>0.7%</td><td>+0.1%</td></tr>
<tr><td>Transmission</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
</table>

17% of Revenue Requirement costs are Distribution demand-related

FOUR KEY ALLOCATORS

DISTRIBUTION CUSTOMER

Rate class share of total number of customers

	F2008	F2013	Change
Residential	88.3%	88.8%	+0.5%
SGS	9.7%	9.3%	-0.4%
MGS	1.3% (> 35 kW class)	0.3%	-0.1%
LGS		0.9%	
Irrigation	0.2%	0.2%	-
Street Lighting	0.6%	0.5%	-0.1%
Transmission	0.0%	0.0%	-

About 8% of Revenue Requirement costs are Distribution Customer-related

2013 COS METHODOLOGY REVIEW REPORT

RICHARD CUTHBERT

CUTHBERT CONSULTING, INC.

BC hydro

FOR GENERATIONS

June 19, 2014

HISTORY

- BC Hydro retained SAIC Energy, Environment & Infrastructure (SAIC) in October 2012; SAIC became Leidos Engineering in September 2013
- Report finalized in December 2013

SCOPE OF REVIEW

- Comprehensive review of BC Hydro's COS analyses, models, spreadsheets used in ratemaking process; discussions with relevant BC Hydro business units
- Jurisdictional review of COS methodologies used by North American electric utilities
  - Focused on key issues from the BCUC 2007 RDA decision
  - Nine utilities in ten jurisdictions selected based on agreed-upon criteria
  - Review conducted jointly by BC Hydro and consultant staff

SUMMARY OF JURISDICTIONAL REVIEW

BC hydro
FOR GENERATIONS

June 19, 2014

SURVEY: KEY ISSUES FOR REVIEW

1. Classification and allocation methodologies for the following types of costs:
   - Hydro resources
   - Thermal generation resources
   - IPP and other purchased power
   - Net power sales income
   - Distribution resources including role of minimum system and zero intercept studies
2. Functionalization, classification and allocation methodologies for DSM program costs
3. Guidelines for rate rebalancing, including appropriate target range of R/C ratios

SURVEY CRITERIA FOR UTILITY SELECTION

- Primarily Hydro Generation Based - Significant portion of generation derived from hydro resources, preferably utility owned but also purchased power
- Winter Peaking Systems - Preference for winter peaking system
- Embedded COS Methodology - Preference for embedded COS methodology, but not excluding utilities that use marginal COS methodology of which there are few
- Vertically Integrated - Preference for providing vertically integrated services, including generation, transmission and distribution of power
- Large Size Systems - Relatively large size of utilities in terms of revenue (greater than $500 million revenues) and customers served (greater than 100,000 customers)

SELECTED UTILITIES

- Avista Corporation (filings with the Idaho Public Utilities Commission and Washington Utilities and Transportation Commission)
- Bonneville Power Administration
- Hydro-Québec Distribution
- Idaho Power Company (filing with the Idaho Public Utilities Commission)
- Manitoba Hydro
- Newfoundland Power Inc.
- Portland General Electric Company
- Puget Sound Energy
- Seattle City Light

The following slides summarize the overall findings, and results for Generation Hydro resources, purchased power and distribution components, and target R/C ratios

SUMMARY OF FINDINGS

Classification Approach:

- No one methodology is predominantly used

Allocation Approach:

- No one methodology is predominantly used
- Minimum System / Zero Intercept Methodologies: Not widely used

R/C Ratios: Some range of reasonableness other than 100% (unity) is typical

HYDRO RESOURCES

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs	O&M Costs Excl Water Costs	Water Costs	
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	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

PURCHASED POWER

	Number of Utilities	% Classified as Demand-Related
Classification Methodologies		
Derived from Classified Plant Costs	1	48%
Energy Only	3	0%
Generation Marginal Costs - Energy Only	1	0%
Generation Marginal Costs - Demand & Energy	1	35%
Supplier COS Results	1	30%
System Load Factor	3	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

BC hydro
FOR GENERATIONS

DISTRIBUTION SUBSTATIONS

	Number of Utilities		% Classified as Demand-Related
	Plant In Service Costs	O&M Costs	
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

DISTRIBUTION LINES

	Number of Utilities		% Classified as Demand-Related
	Plant In Service Costs	O&M Costs	
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

BC hydro
FOR GENERATIONS

DISTRIBUTION TRANSFORMERS

	Number of Utilities		% Classified as Demand-Related
	Plant In Service Costs	O&M Costs	
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

DISTRIBUTION SERVICES

	Number of Utilities	% 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

DISTRIBUTION METERS

	Number of Utilities		% Classified as Demand-Related
	Plant In Service Costs	O&M Costs	
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

BC hydro
FOR GENERATIONS

TARGET AND ACTUAL R/C RATIOS

Approaches for Establishing R/C Ratios for Proposed Rate Design	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
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%
Multiple 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%

* Jurisdictions which target R/C ratios of 100% typically also impose bill impact restrictions (i.e. no rate decreases, maximum bill impact threshold)

BC hydro FOR GENERATIONS

SUMMARY OF RECOMMENDATIONS

FOR GENERATIONS

June 19, 2014

FINDINGS OF REVIEW

BC Hydro's COS Approach

- Generally consistent with standard embedded COS methodologies
- One exception is classification of customer care costs as 65 percent demand and 35 percent customer per outcome of 2007 RDA

General Observation

- Unless specifically addressed, implication is that BC Hydro's COS methodologies are generally acceptable
- Evaluating the feasibility of performing the sub-functionalization of costs required for several of the suggested approaches was beyond the scope of the review

Methodology Review – Customer Input

- BC Hydro circulated its strawman responses to the December 2013 COS Methodology Review on 17 June 2014
- The strawman responses and these slides should be read together

SUMMARY OF RECOMMENDATIONS

AND BC HYDRO’S STRAWMAN RESPONSES

Functionalization

BC hydro
FOR GENERATIONS

June 19, 2014

RESPONSE TO RECOMMENDATIONS

#1 DSM Functionalization

Recommendation #1

Consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service

BC Hydro proposes the following for modelling purposes:

- 90% Generation
- 5% Transmission
- 5% Distribution

- DSM is primarily acquired to offset more expensive Generation resources.
- Most utilities treat DSM as a Generation expense
- DSM has some Transmission and Distribution deferral benefits:
  - Some regional deferral benefits on the transmission system
  - Some distribution deferral benefit, primarily substations

SUMMARY OF RECOMMENDATIONS

AND BC HYDRO'S STRAWMAN RESPONSES

Classification

BC hydro

FOR GENERATIONS

June 19, 2014

GENERATION COS METHODOLOGIES CLASSIFICATION

Recommendation #2

Hydro Resources Costs

- System load factor approach **or**
- Plant capacity factor approach that sub-functionalizes hydro resources by individual plant or groups of plants

Recommendation #3

Peaking Thermal Resources Costs

- Continue to classify peaking thermal plant costs as demand-related, except fuel costs

Recommendation #4

IPP and Other Purchased Power Costs Classification

- Modify Existing 100% energy IPP classification to reflect either:
  - fixed versus variable payment obligations **or**
  - capacity versus energy usage

Recommendation #5

Subsidiary Income Classification

- Continue to use split between demand-related and energy-related generation revenue requirements

RESPONSE TO RECOMMENDATIONS

#2: Hydroelectric Classification

BC Hydro is considering the two recommended approaches:

Option 1: Load factor approach

- Would be based on the F16 load forecast
- The calculation is relatively stable year over year and the approach recognizes that the system is built to serve domestic load
- Consistent with many other hydroelectric utilities (ex. Hydro Quebec, Newfoundland Power, Avista)

Option 2: Capacity factor approach

- Reflects system reserve margin and the fact the system is operated to maximize net economic benefit over a 3-5 year operational period
- Variability could be an issue – using normal water could mitigate

RESPONSE TO RECOMMENDATIONS

#3 Thermal Classification

Fort Nelson Generation Station (GS)	• Primarily base loaded • Propose to classify as both energy and demand- related
Prince Rupert GS	• Provides backup in the event of transmission outages (500 kV system from Prince George to Prince Rupert) • Propose to classify as both energy and demand- related
Burrard GS	• Used primarily for emergency backup and system support • Propose to classify as 100% demand with fuel costs treated as 100% energy (current approach)

BC hydro
FOR GENERATIONS

RESPONSE TO RECOMMENDATIONS

#4 IPP Classification

Proposed approach:

- Link demand classification to capacity contribution in long term planning (2013 Integrated Resource Plan (IRP))
- Use either the value of energy and capacity (option 1) or the value of capacity (option 2)

Other options considered:

- Contract structure (option 3)
- Resource contribution (option 4)
- Load factor (option 5)

RESPONSE TO RECOMMENDATIONS

#4 IPP Classification

Proposed approach details:

Two options tested:

1. % cost allocated to demand = $\dfrac{\text{capacity benefits (\$)}}{\text{sum of firm energy and capacity benefits (\$)}}$

2. % cost allocated to demand = $\dfrac{\text{capacity benefits (\$)}}{\text{IPP payments (\$)}}$

- Benefits estimated based on firm energy (GWh) and capacity (MW) contributions reflected in 2013 IRP, valued at energy and capacity prices:
  - at the time of the Clean Power Call (CPC)
  - at current Long-Run Marginal Cost (LRMC)

RESPONSE TO RECOMMENDATIONS

#4 IPP Classification: Value of Energy and Capacity (option 1)

	Total Cost	% Demand if CPC Prices	% Demand if LRMC
Island Generating Plant (ICG)	59	3%	7%
McMahon	51	3%	7%
Biomass	257	3%	7%
Alcan	63	9%	16%
Wind	107	2%	5%
Small Hydro	332	2%	3%
Storage Hydro	106	3%	5%
TOTAL F16 COST AND WEIGHTED DEMAND ENERGY RESULTS	$975 MILLION		

#4 IPP Classification: Value of Capacity (option 2)

	Total Cost	% Demand if CPC Prices	% Demand if LRMC
ICG	59	17%	27%
McMahon	51	8%	12%
Biomass	257	5%	8%
Alcan	63	9%	14%
Wind	107	3%	5%
Small Hydro	332	1%	2%
Storage Hydro	106	5%	8%
TOTAL F16 COST AND WEIGHTED DEMAND ENERGY RESULTS	$975 MILLION		

Observations:

- Both options result in <5% demand-related classification for intermittent resources
- Option #2 better recognizes the difference in capacity contribution between resource options
- Current LRMC better reflects current capacity benefits

RESPONSE TO RECOMMENDATIONS

#5 Powerex Net Income Classification

- The approach approved by the BCUC in the 2007 RDA (Directives 7 & 10) should continue to be used

TRANSMISSION COS METHODOLOGIES CLASSIFICATION

Recommendation #6

Backbone or Network Transmission Resources Costs

- Continue to classify as demand-related

Generation-Related Transmission Resources Costs

- Classify and allocate in same manner as costs for the generation resources

Radial Transmission Resources Costs

- Classify as demand-related

RESPONSE TO RECOMMENDATIONS

#6 Transmission Classification

- BC Hydro already functionalizes Generation Related Transmission lines as 100% Generation
- BC Hydro agrees that Transmission should continue to be treated as 100% demand
  - Serving peak load is the primary planning consideration and driver of capital expenditures.

DISTRIBUTION AND CUSTOMER CARE COS METHODOLOGIES CLASSIFICATION

Recommendation #7

Sub-Functionalization or Direct Assignment

- Consider more detailed sub-functionalization of Distribution system costs as data allows
- If possible use more direct assignment of Distribution costs (e.g., transformers, services, and meters) based on fixed asset records
- Consider using weighted number of customers when calculating the allocation factors for transformer, services and meter costs

Recommendations #8 & #9

Minimum System and Zero Intercept Studies

- Use is declining due to complexities and difficulties in collecting data
- Trend is towards classifying Distribution costs as either demand-related or customer-related
    - Services and meters costs most often classified as customer-related
    - Substations, lines and transformers most often classified as demand-related

DISTRIBUTION AND CUSTOMER CARE COS METHODOLOGIES - CLASSIFICATION

Recommendations #8 & #9

2010 Distribution System Study and Distribution Cost Classifications

- Difficulties in preparation and application encountered, as is common in the industry
- Re-examine and update prior to any use
- Goal is to be as consistent as possible with theoretical foundation of the minimum system method and zero-intercept method as described in the *1992 NARUC Manual*
- As an alternative, consider classification of Distribution substation, lines and transformer costs as all demand-related ,and services and meter costs as all customer-related

Recommendation #10

Customer Care Costs

- Classify most, if not all, as customer-related

RESPONSE TO RECOMMENDATIONS

#7 - 9 Distribution Classification

- The Distribution system is a challenging topic due to the diversity of the system, (rural vs. urban, overhead vs. underground, single phase vs. three phase), as well as the number of different types of equipment (substations, switchgear, poles, duct banks, wires, cables, transformers, and meters)
- The Minimum System/Zero Intercept study completed in May 2010 produced results that were highly sensitive to the methodology chosen:

Table 29 Summary of Classification Results

Classification Method	Demand	Customer
Zero Intercept (Segments)	48%	52%
Zero Intercept (Aggregate)	53%	47%
Min System	42%	58%
Direct Assignment	66%	34%
Appropriate Method	75%	25%

BC hydro
FOR GENERATIONS

RESPONSE TO RECOMMENDATIONS

#7 - 9 Distribution Classification

Alternatives:

- BC Hydro is examining categorizing Distribution costs by asset type (e.g., substations, primary, secondary, transformers, meters) and then classifying as either entirely demand related or customer related
- BC Hydro is also exploring direct assignment of Distribution assets to customer classes on a feeder by feeder basis
- We propose to investigate these approaches and report back to stakeholders at an October 7, 2014 COS workshop

RESPONSE TO RECOMMENDATIONS

#10 Customer Care Classification

- BC Hydro agrees that Customer Care should be classified as 100% customer-related
- This would be consistent with how other utilities treat customer care costs
- Customer Care costs do not vary with demand

SUMMARY OF RECOMMENDATIONS

AND BC HYDRO'S STRAWMAN RESPONSE

Allocation

BC hydro

FOR GENERATIONS

June 19, 2014

GENERATION COS METHODOLOGIES:
ALLOCATION (DEMAND RELATED COSTS)

Recommendations #11 - #13

Hydro Resources Costs

- BC Hydro should analyze how hydro units are designed / used to serve peak loads
- If designed / used to meet peak loads throughout the entire year, then 12 CP method is appropriate
- If designed / used to help meet peak loads during only a few months of the year, then methods such as 3 CP or 4 CP are more appropriate
- Must be considered in context of type of classification factor used
- Both system load factor or plant capacity classification approaches inherently acknowledge that hydro resources are used for baseload and peak demand purposes
- As an alternative approach, BC Hydro might consider using the Average and Excess method

Peaking Thermal Resources Costs

- Use allocator that reflects the classes' contributions to the coincident peak demands in the months when the thermal plants are primarily used

RESPONSE TO RECOMMENDATIONS

Generation Energy Allocation

- BC Hydro believes that energy related Generation costs should continue to be allocated to rate classes on a pro rata basis

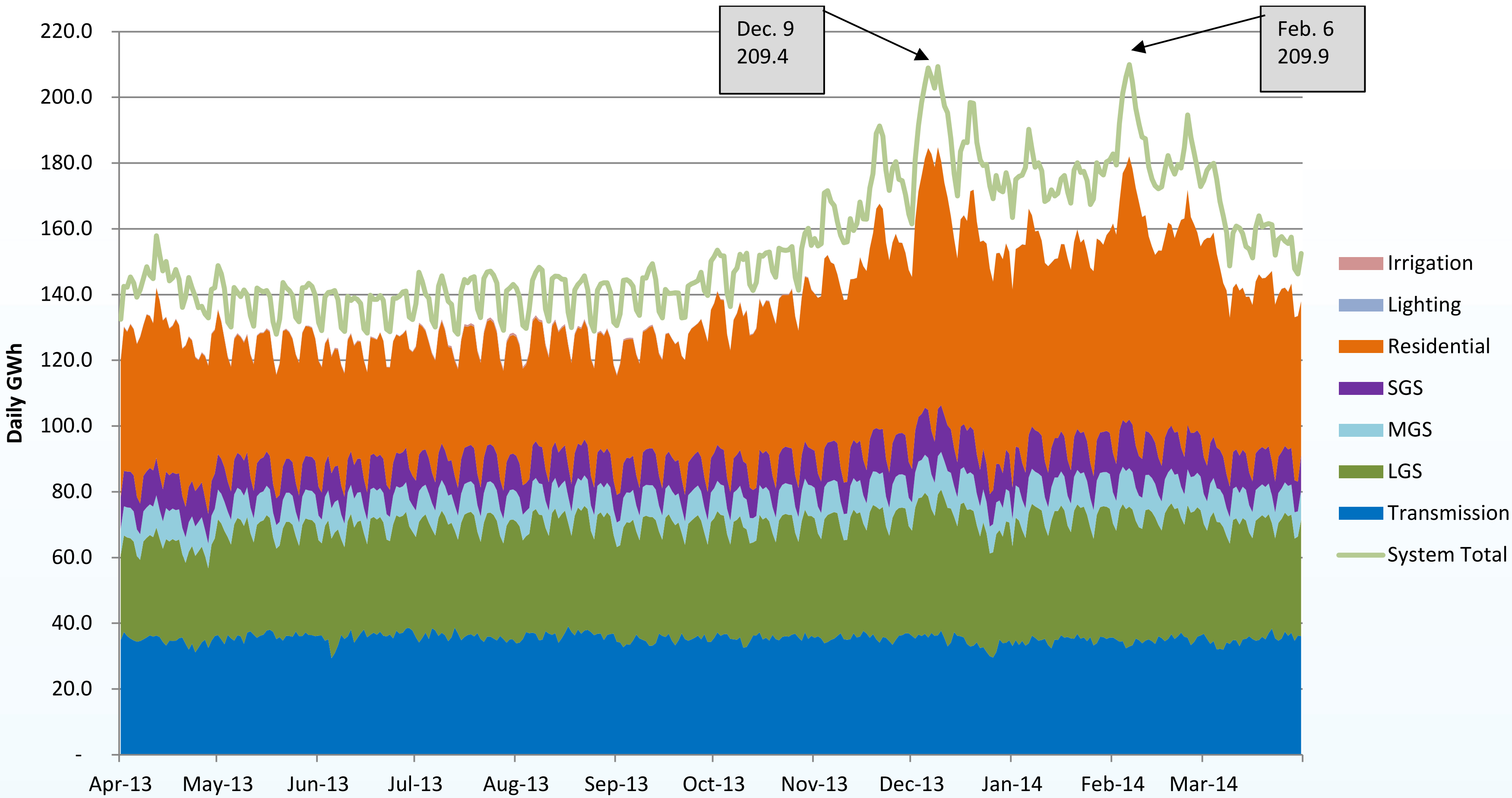
RESPONSE TO RECOMMENDATIONS

#11-13 Generation Demand Allocation

- Generally, all hydroelectric units are planned and operated such that they will be available to meet the winter peak
  - Operation is based on maintenance requirements and inflow considerations
- BC Hydro believes a 4 CP allocator remains a reasonable method of allocating hydroelectric Generation demand costs
- The winter season continues to be the predominant factor impacting planning across BC Hydro Generation, Transmission and Distribution
- Generation planning is focused on ensuring all units are available for the Nov-Feb winter season

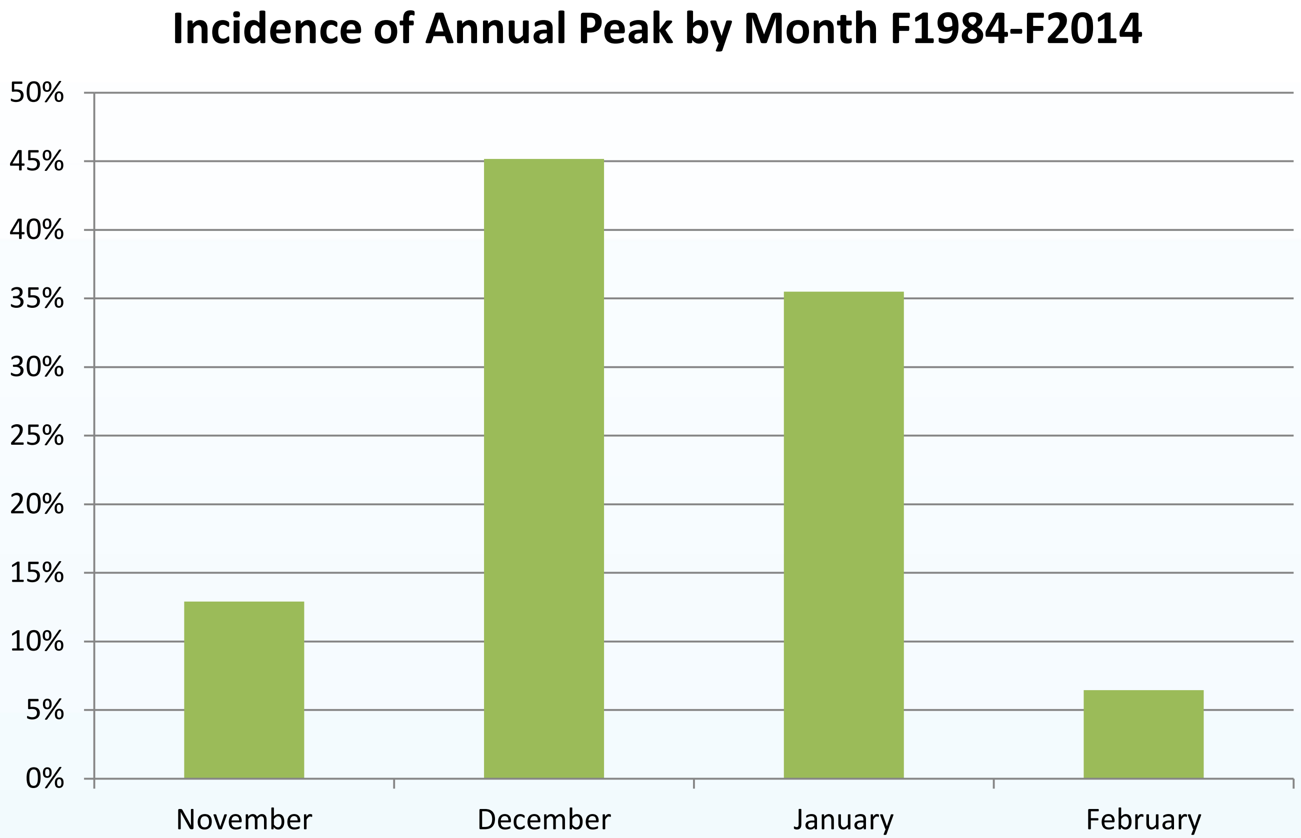
#11-13 Generation Demand Allocation

F2014 RATE CLASS LOAD – DAILY ENERGY GWHS



#11-13 Generation Demand Allocation

The graph shows the percentage that the annual system peak has occurred in November, December, January, and February between F1984 and F2014. The annual peak has never occurred in any other month.



This illustrates that 4 CP is a reasonable allocation method as opposed to 1 CP

TRANSMISSION COS METHODOLOGIES

ALLOCATION: (ALL DEMAND-RELATED)

Recommendations #14

Backbone or Network Transmission Resources Costs

- Consider how Transmission assets are designed and used and BC Hydro’s load patterns
- May be appropriate to sub-functionalize these Transmission costs between areas using different types of allocation factors for each

Recommendations #15

Radial Transmission Resources Costs

- Give consideration to using NCP as the demand allocator

RESPONSE TO RECOMMENDATIONS

#14-15 Transmission Allocation

- Asset investments and Transmission planning continue to be primarily driven by winter peak loads
- BC Hydro proposes to continue with a 4 CP approach to allocate Transmission costs
- Transmission planning is influenced by both Transmission voltage customer loads and Distribution substation loads
- BC Hydro will investigate whether it can identify individual loads and the individual asset values of radial Transmission lines

#14 Transmission Allocation

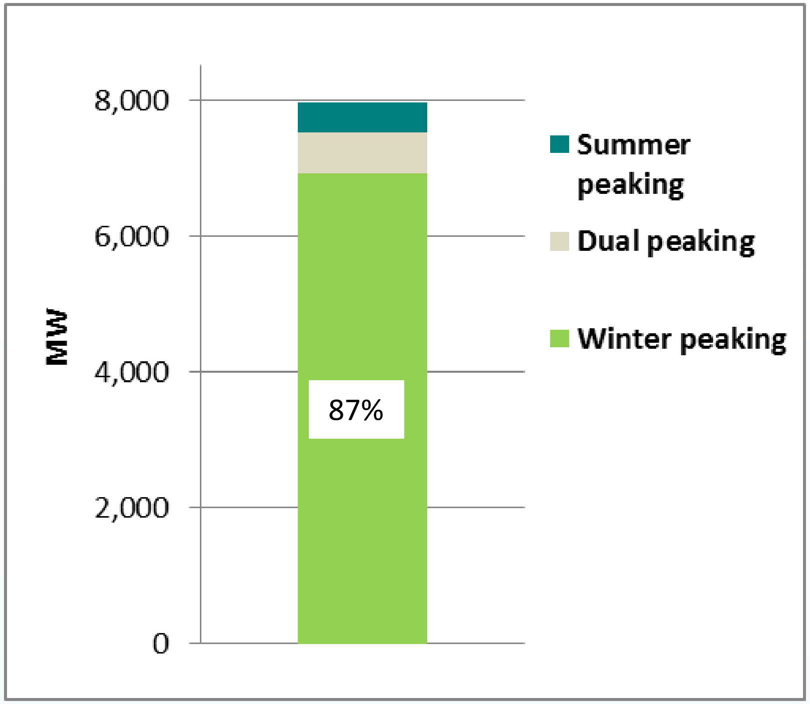
PEAK LOADS – DISTRIBUTION SUBSTATIONS

- In F2013 there were 219 distribution substations on the integrated system
  - 85% of the stations were winter peaking (188 substations)
  - 3% were dual peaking (the summer peak was within +/- 10% of the winter peak) (6 substations)
  - 12% were summer peaking (25 substations)

#14 Transmission Allocation

PEAK LOADS – DISTRIBUTION SUBSTATIONS

System Perspective

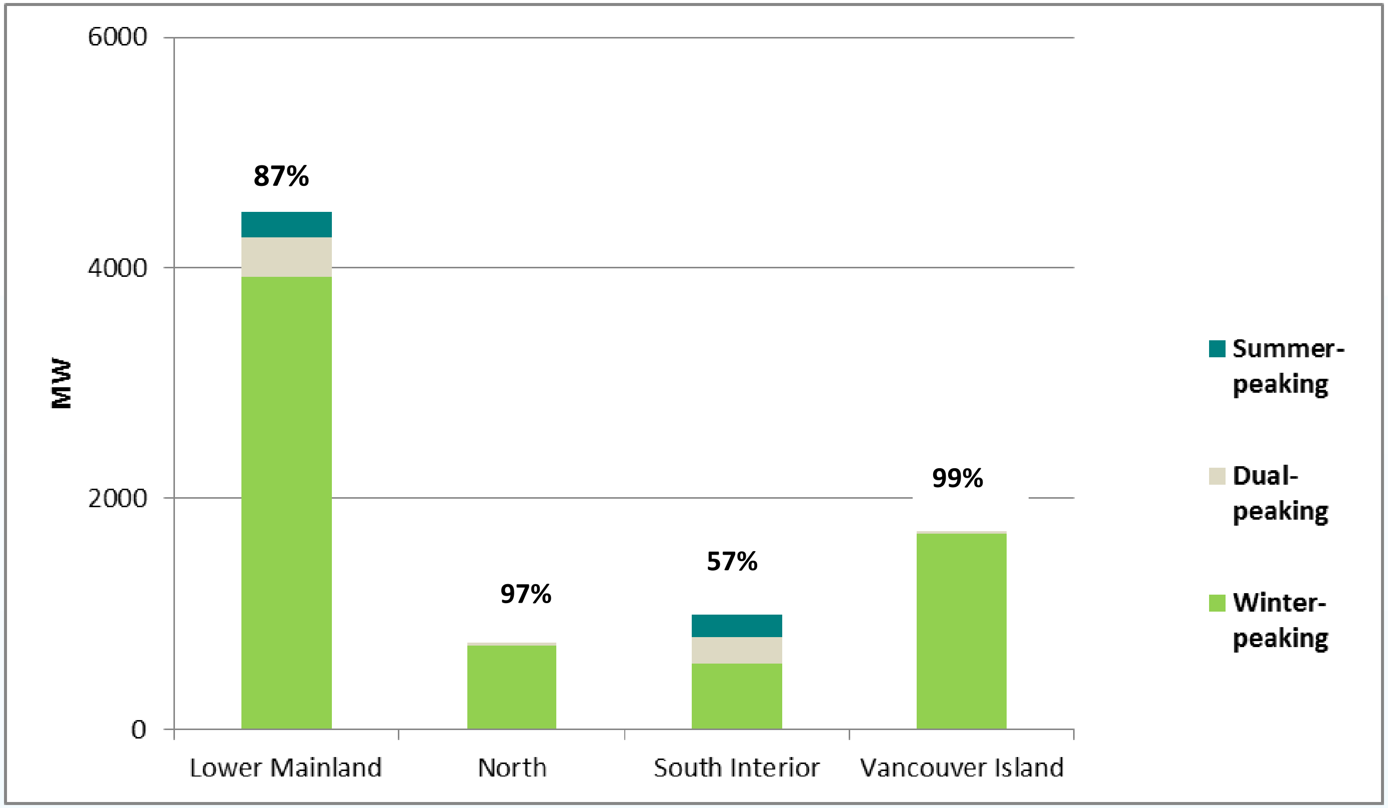


In F2013, 87% of the non-coincident peak distribution substation loads were winter peaking

- summer peak load at the 188 winter-peaking substations is 55.5% of the total winter load
- winter peak load at the 25 summer-peaking stations is 94% of the summer load

#14 Transmission Allocation

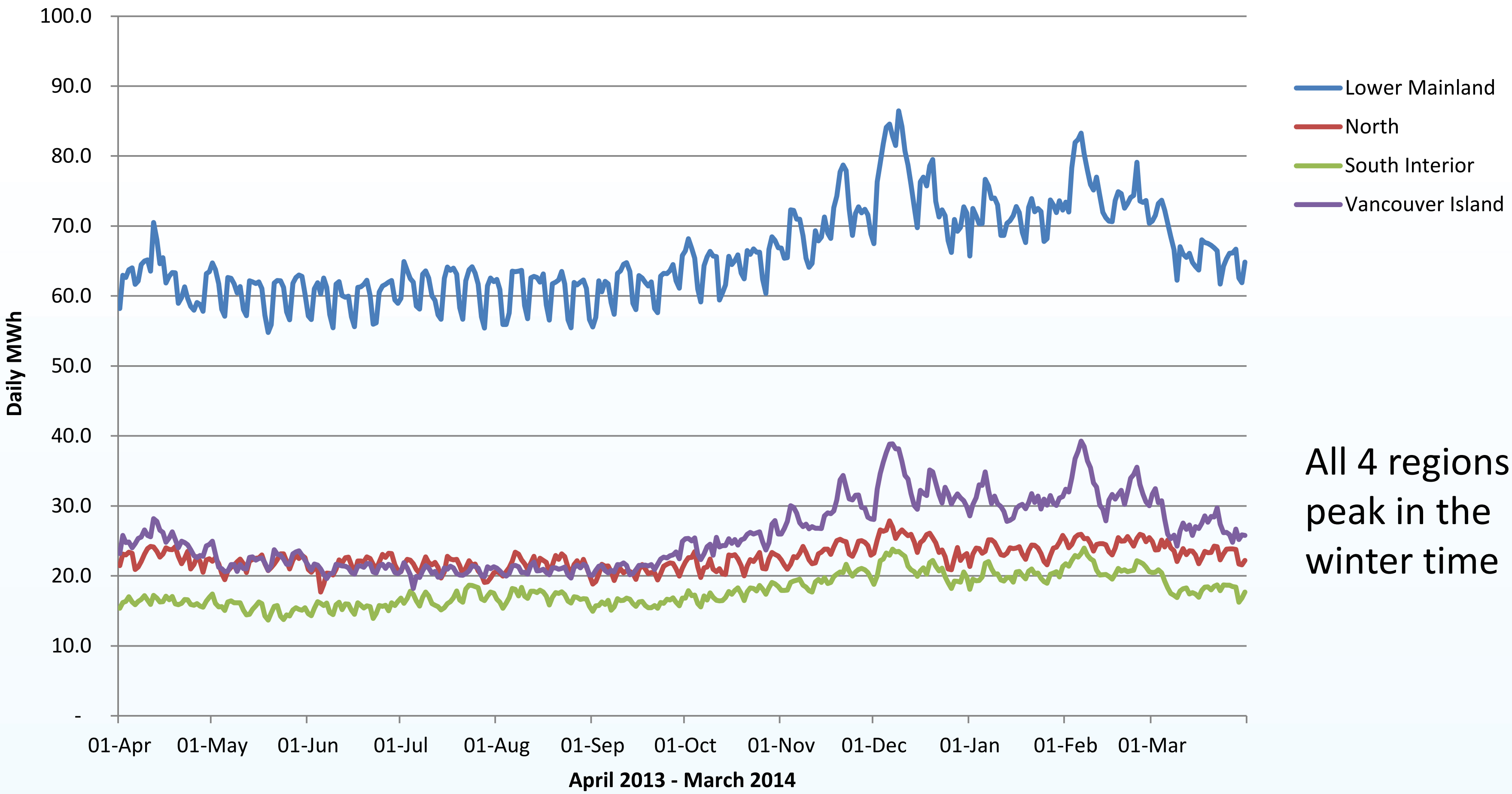
PEAK LOADS – A REGIONAL PERSPECTIVE



The graphs show the percentage of the non-coincident regional peak load that is winter peaking

#14 Transmission Allocation

F2014 REGIONAL LOAD PROFILES



All 4 regions peak in the winter time

Transmission + Distribution Voltage loads

RESPONSE TO RECOMMENDATIONS:

#16 Distribution Allocation

Recommendation #16

Consider using more direct assignment of Distribution costs

- BC Hydro proposes to investigate direct assignment of Distribution assets to customer classes on a feeder by feeder basis and report back to stakeholders at the October 7, 2014 COS workshop
- The proposed method would identify each customer classes' load on a sample of Distribution feeders along with the cost of those feeders
- If this approach is not feasible, BC Hydro suggests that the current NCP allocation approach be continued

SUMMARY OF RECOMMENDATIONS

R/C ratios and Ranges of Reasonableness

BC hydro
FOR GENERATIONS

June 19, 2014

APPROPRIATE R/C RATIOS

Recommendations #17 & #18

Target Revenue to Cost Ratios

- Target R/C ratios should be considered as 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.)
- Some variability from a unity R/C ratio target should be acceptable to provide general rate consistency over time
- There should be some flexibility in making decisions regarding rate design to meet other types of policy objectives
- BC Hydro should consider more explicitly developing a policy for how rapidly customer classes should be moved towards this range of reasonableness for R/C ratios

APPROPRIATE R/C RATIOS

Range of Reasonableness

- Both the 90 percent to 110 percent range proposed by BC Hydro in the 2007 RDA and the BCUC’s directed 95 percent to 105 percent range are reasonable and consistent with generally accepted utility practice
- BC Hydro should consider adopting range of reasonableness for customer class R/C ratios with 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

RESPONSE TO RECOMMENDATIONS

#17 – 18 Range of Reasonableness

- The customer class R/C ratios in BC Hydro's F2013 FACOS range from 87 percent to 127 percent
- BC Hydro proposes a range of reasonableness of 95% - 105%
- As compared to 2007, BC Hydro has improved load research information
- There is jurisdictional support for a 95% - 105% range of reasonableness
- A range continues to be appropriate given that there are many assumptions prevalent in the COS, and the results are sensitive to the particular methodologies selected

OTHER TOPICS – CUSTOMER CARE ALLOCATION

Customer Care Allocation

- BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with:
    - o 90% of the weight based on the number of bills issued to customers
    - o 10% based on revenue
- A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor

OTHER TOPICS – SMI

- BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI

SMI CLASSIFICATION BOOKENDS:

1. Treat SMI costs as 100% customer-related
   - Consistent with historical treatment for meter-related costs
   - Energy savings not readily quantifiable at this early stage in SMI

2. Treat SMI costs as 100% energy-related
   - SMI was installed primarily for energy-saving benefit

100% customer-related?

100% energy-related?

OTHER TOPICS – E-PLUS

- BCUC Directive #14 from the 2007 RDA stated:
  "Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months"

POSSIBLE BOOKEND OPTIONS:

1. Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter
2. Continue to include E-Plus customers in the 4 CP calculation
   - These loads are in BC Hydro's load forecast and planning
   - There is no operational ability to interrupt; true Interruptibility would be expensive and administratively complex

BC Hydro proposes option #2

BC hydro FOR GENERATIONS

NEXT STEPS

- There will be a 45-day written comment period from the posting of summary notes of this workshop on BC Hydro's 2015 RDA website
- BC Hydro proposes an October 7, 2014 workshop to review a draft Cost of Service Study (COSS)
  - Incorporate new methodologies
  - Present draft COSS including R/C ratios
  - Report back on the feasibility of more direct assignment of Distribution assets to rate classes

QUESTIONS?