Draft

BC Hydro Rate Design Workshop

SUMMARY | 25 JUNE 2015 | 9 AM TO 11.45 AM | BCUC Hearing Room, 1125 Howe Street, Vancouver

TYPE OF MEETING	RDA Workshop 11A
FACILITATOR	Anne Wilson, BCH
PARTICIPANTS	Association of Major Power Consumers of British Columbia (AMPC); British Columbia Old Age Pensioners Organization (BCOAPO), BC Sustainable Energy Association and Sierra Club of Canada BC Chapter (BCSEA), BCUC staff, Canadian Office and Professional Employees Union Local 378 (COPE 378), Clean Energy BC/Weimer Consulting Inc., CLEAResult, Commercial Energy Consumers Association of British Columbia (CEC), First Nations Energy & Mining Council/Linda Dong Associates (FNEMC), FortisBC Inc. (Fortis), TransLink
BC HYDRO ATTENDEES	Gordon Doyle, Rob Gorter, Paulus Mau, Dani Ryan, Anne Wilson, Craig Godsoe, Jeff Christian (Lawson Lundell)
AGENDA	1. Welcome & Introductions 2. Overview of GS Rates, Stakeholder Engagement to Date and Issues Identified 3. GS Segmentation 4. SGS 5. MGS – Preferred Energy Rate and Demand Charge Structure Alternatives 6. MGS – Demand Charge Cost Recovery 7. MGS – Transition Options

MEETING MINUTES

ABBREVIATIONS	BCH ...... BC Hydro BCUC……BC Utilities Commission COS……..Cost of Service CP……….Coincident Peak DSM ...... Demand Side Management E3…………Energy + Environmental Economics, Inc. GS……….General Service GWh…….Gigawatt hour IPP........ Independent Power Producer kW……….Kilowatt	kWh……..Kilowatt hour LGS………Large General Service LTAP…….Long-Term Acquisition Plan MGS…….Medium General Service NCP……..Non-Coincident Peak R/C……….Revenue to Cost ratio RDA……..Rate Design Application RIB……..Residential Inclining Block rate SGS……..Small General Service SQ……….Status Quo

1. Welcome and Introductions

Anne Wilson opened the meeting by reviewing the agenda set out in slide 2 of the Workshop 11A slide deck.

2. Presentation: GS Rate Overview

Gordon Doyle stated that BCH now has a preferred SGS rate structure, which is the SQ flat energy rate, and a preferred MGS energy rate structure, which is a flat energy rate with no baseline.

Gord described the purpose of Workshop 11A, which is to solicit feedback on: (1) what additional GS rate class segmentation analysis should be conducted; (2) whether BCH should increase the SGS basic charge cost recovery; (3) what should the preferred MGS demand charge structure be; (4) whether BCH should increase the MGS demand charge cost recovery; and (5) what should the preferred MGS transition option be.

Gord also reviewed stakeholder engagement on GS rates to date, including BCH's GS jurisdictional assessment results and issues identified with the SQ MGS and LGS rates.

	FEEDBACK	RESPONSE
1.	**BCOAPO**	The basis of the LGS and MGS forecasted conservation savings is a commercial customer elasticity assumption of -

	What is the basis of the LGS and MGS forecasted conservation savings shown on slide 8?	0.1 for rate structure conservation. The -0.1 elasticity assumption results from a jurisdictional and literature survey done by E3 as part of the BCH 2008 LTAP review. E3 focused on winter peaking jurisdictions, including Ontario, Illinois, Wisconsin and New York.[1]
2.	**BCOAPO** In BCH's view, were the original commercial customer elasticity assumptions flawed or is the lack of LGS and MGS customer response to the SQ two-part baseline rates due to customers not understanding the price signals and therefore being unable to react?	As discussed at Workshop 8A, one common theory behind LRMC-priced rate structures is that awareness leads to understanding and understanding results in a conservation response. If awareness is low, as was found for the LGS and MGS rates, then understanding and conservation actions are also expected to be low.[2]
3.	**BCUC staff** -0.1 is a fairly low elasticity of demand; we may be spending too much time trying to get the price signal right for the diverse LGS and MGS rate classes instead of addressing what rate structure would work best for these classes.	

3. Presentation: GS Segmentation

Dani Ryan described the two main GS segmentation issues raised by stakeholders as part of Workshop 8A/8B: (1) segment the existing LGS rate class to create a new class of larger LGS customers (referred to as **XLGS**); and (2) possible re-merging of MGS and LGS rate classes. Dani discussed analysis BCH has done to date (jurisdictional assessment and COS analysis 'Method 1') and the additional analysis BCH is undertaking and targeting to discuss at the 30 July 2015 RDA wrap-up workshop (COS analysis 'Method 2', which is clustering analysis).

Dani emphasized that to date, BCH is finding that no matter how the GS could be segmented, its heterogeneity would remain; there is no obvious breakpoint for segmenting the GS rate class beyond the current segmentation into SGS, MGS and LGS rate classes.

	FEEDBACK	RESPONSE
1.	**AMPC** On slide 13, BCH states that metering is one basis for the existing SGS rate class demarcation at 35 kW. AMPC would like an update on whether there is now increased metering capability.	There is increased metering capability. However, at Workshop 8A BCH described how about 45% of SGS customers have residential-type meters and these meters do not have Measurement Canada approved demand functions.[3] Thus while demand can be calculated using interval data it cannot be used for billing. BCH's jurisdictional assessment revealed that Canadian electric utilities surveyed have small GS classes which do not have demand charges, and that the current SGS 35 kW breakpoint is within the range of other Canadian electric utility breakpoints used for smaller GS (10 kW to 75 kW). Refer to slide 15.

[1] The four non-residential studies E3 viewed as most comparable to B.C. report short-run elasticities of between 0.0 and -0.142, with three of the four studies reporting short-run elasticities below -0.1. Refer to the Direct Testimony of Dr. Ren Orans, 2008 LTAP Appendix E, pages 19 and 20 of 28; http://www.bcuc.com/Documents/Proceedings/2008/DOC_18928_B-1-1_APPENDICES.pdf.

[2] Refer to the Workshop 8A/8B Consideration Memo, Attachment 1, page 3 of 29; http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-06-19-bch-rda-wksp-8a-8b-gsrs.pdf.

[3] Per the Electricity and Gas Inspection Regulations, SOR/86-131; copy available at http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131/.

2.	**AMPC** AMPC agrees with BCH's comment that it is general utility practice to have a small GS rate class with no demand charge.	
3.	**AMPC** AMPC notes the prevalence of very large GS classes on slide 15 e.g., Toronto Hydro 5,000 kW breakpoint; Epcor 5,000 kW breakpoint. What is the number of BCH LGS accounts at 5,000 kW?	This information is set out at page 44 of the Workshop 8A/8B Consideration Memo: 5,000 kW: 37 accounts; 2,000 kW: 172 accounts; 1,000 kW – 437 accounts. BCH is still investigating the COS basis for the creation of a XLGS rate class say above a 2,000 kW breakpoint. BCH will also explore whether E3's other factors for segmentation - customer understanding and practicality of tariff administration – support different breakpoints, for example for a XLGS class.
4.	**BCOAPO** On slides 17 and 18, the issue that the analysis seems to miss is that the MGS and LGS customers are not billed using Energy/NCP/4CP – rather they are billed strictly on energy and their individual monthly NCP. The other issue missed in the analysis is that the amount of dollars allocated to each class using energy is not equivalent to the dollars collected from customers through energy rates. The implications of the first point are: • Ideally one would want to group in the same rate class customers whose ratio of Billing Demand is similar to 4CP; • Similarly one would want to group in the same rates class customers whose ratio of billing demand to NCP are similar. The implications of the second point are: • Ideally one would want to group into the same rate class customers that have the same load factor (measured using NCP); • Similarly one would want to look at grouping customer into the same rate class that have similar load factors measured using 4 CP. Based on these observations it would be interesting to see how each of the three ratios vary across individual customers when "plotted" against customer size (i.e. peak) in order to see if there are any obvious break points.	Slides 17 and 18 are looking at segmentation from a cost perspective alone, which E3 did in 2009. BCOAPO seems to be asking BCH to relate the costs to the revenue. It is not apparent to BCH why one would calculate a load factor using 4 CP. The standard load factor calculation is already based on the customer's peak demand or NCP. • The relationship between a customer's Billing Demand and 4CP would be similar to the relationship between load factor and coincidence factor. It is not clear how this could be used for rate class segmentation. • The ratio of billing demand to NCP would be similar to load factor and there is no cost basis for grouping customers this way. • Load factor does not drive costs and should not be used as the basis for rate class segmentation. • While coincidence factor may predict cost causation, it is not a practical way of segmenting customers.
5.	**FortisBC** Has BCH done a statistical cluster analysis?	Not yet; as set out in the Workshop 8A/8B Consideration Memo, BCH will be doing a cluster analysis as part of Method 2 and anticipates being able to discuss the results with stakeholders at the 30 July 2015 workshop.

6.	**BCSEA** Is the Method 2 cluster analysis a COS method?	Yes.
7.	**BCSEA** Given the importance of coincidence factor, can coincidence factor be used as a basis for GS segmentation?	Coincidence factor is variable; there is no GS subset that is entirely coincident with system peak. E3 stated as part of its 2009 GS segmentation analysis that customer accounts should be segmented using readily observable variables that can be easily understood, together with other factors such as customer understanding and practicality of tariff administration. BCH is not aware of any Canadian jurisdiction that uses coincidence factor to segment GS customers. BCH does not think that coincidence factor (or load factor) meets these requirements; instead, BCH agrees with E3 that BCH should continue to use kW demand intervals as the basis for GS class segmentation.
8.	**CLEAResult** The finding that load factor does not relate too strongly to cost is incredible. BCH may be able to do more rate innovation if coincident factor is really the main cost driver.	Load factor is the relationship of average use (measured in kWh) to peak use (measured in kW). A customer's load factor is only related to cost to the extent that their peak use occurs coincidently with other customers' peak use, which is better expressed as coincidence factor. Load factor is more predictive of revenue impacts, especially when cost recovery is shifted between energy charges and demand charges.
9.	**CEC** There appears to be a relationship between low load factor and low coincidence factor on slide 20. Could this group be segmented?	If we just examine low load factor customers, some of these will have high coincidence. BCH has concerns with using load factor to segment GS customers as this concept is not readily understood by customers and changes with the addition of equipment, for example. In BCH's view, using load factor to segment does not meet either the customer understanding or practicality of tariff administration tests. Instead, as will be described in Workshop 11B, BCH will review a demand charge option for low load factor, low coincidence customers (referred to as the Manitoba Hydro Limited Use of Billing Demand option).

4. Presentation: SGS Rate

Rob Gorter set out the reasons why BCH's preferred SGS rate is the SQ SGS flat energy rate with a basic charge and no demand charge. Rob also discussed the results of increasing the SGS basic charge fixed cost recovery from about 35% to about 45%, which is the level of the RIB basic charge fixed cost recovery.

	FEEDBACK	RESPONSE
1.	**CEC** The draft F2016 COS shows that BCH is over-recovering from the SGS rate class. Would rate-rebalancing cause BCH to reconsider the SGS rate structure?	BCH does not see possible rate-rebalancing causing BCH to consider a different SGS rate structure. An inclining block rate is not viable for this heterogeneous class and a two part baseline rate such as the SQ MGS rate is not appropriate for this class regardless of rate rebalancing.

2.	**COPE 378** What is the LRMC range for comparison to the SGS energy charge? How confident is BCH in the energy LRMC range?	This information is set out at page 7 of the Workshop 8A/8B Consideration Memo. For F2016, the energy LRMC range is 9.36 cents/kWh (lower end) and 11.01 cents/kWh (upper end). As shown on slide 24, the SGS energy charge in F2016 is 10.73 cents/kWh, which is within the energy LRMC range. The energy LRMC range results from the approved 2013 Integrated Resource Plan, which found that the two resources types required to fill the energy gap over the next ten years is DSM and IPP contract renewals, and this resulted in a range of 8.5 cents/KWh to 10.0 cent/kWh (F2013).
3.	**BCOAPO** Did increasing the SGS basic charge result from stakeholder feedback?	Yes, as did the level of possible SGS basic charge increase to 45% fixed cost recovery.
4.	**BCOAPO** What does BCH mean by 'fixed costs'? Can BCH provide what % of customer costs are recovered by the SQ RIB basic charge and the SQ SGS basic charge?	On slide 27, fixed costs are demand- and customer-related costs. Both the SQ RIB basic charge and SQ SGS basic charge recover all customer costs and a portion of demand costs, with most demand costs being recovered through the respective energy charges.
5.	**BCSEA** What is the effect on energy conservation if BCH were to increase the SGS basic charge fixed cost recovery to 45%?	As shown on slide 26, the resulting reduction in the SGS energy charge is very small – in F2017 from 11.16 cents/kWh to 11.01 cents/kWh. Applying the -0.05 elasticity assumption BCH has for natural conservation through rate increases, there may be a very small increase in energy consumption.
6.	**BCUC staff** Any resulting increase in energy consumption would be so small as to be negligible.	
7.	**BCOAPO** BCH concludes that increasing the SGS basic charge fixed cost recovery to 45% would not result in 'substantial' bill impacts. How does BCH define substantial given the bill impact is over 10% for the first two percentile consumption categories on slide 26?	BCH continues to use the 10% bill impact test as an 'amber signal' rather than a stop or go constraint. This is particularly the case where, as in this case, the absolute dollar value of the increases is small.
8.	**CEC** CEC agrees that absolute dollar value is an important part of the 10% bill impact test.	

9.	**BCOAPO** It would be useful to know how many SGS customers fall into each of the percentile consumption categories on slide 26.	The distribution on slide 26 illustrates bill impacts of the single account at each specified percentile, as opposed to the impact of a group of accounts in blocks of 10%. For example, the result for the 10th percentile shows the bill for the single account that represents the 10th percentile of consumption of accounts in the F2014 sample used for the analysis. The forecasted number of SGS accounts, which this distribution will apply to, for illustrative purposes are below.

Forecast year	Forecast number of accounts	10 percent of forecasted accounts
F17	181,698	18,170
F18	183,727	18,373
F19	185,817	18,582

5. Presentation: MGS Demand Charge Structure Alternatives

Paulus Mau reiterated that BCH's preferred energy rate structure is a flat energy rate with no baseline. The MGS Flat Energy Rate would be very close to the lower end of the energy LRMC range, with an energy charge of 8.98 cents/kWh in F2016 as compared to the lower end of the energy LRMC of 9.36 cents/kWh ($F2016).

Paulus identified and reviewed the BCH Bonbright assessment of three demand charge structure alternatives: the three step SQ Demand Charge; the Flat Demand Charge; and the Two Step Demand Charge, which retains the current zero Tier 1 and flattens Tier 2 and Tier 3 into a single Tier 2.

	FEEDBACK	RESPONSE
1.	**BCUC staff** It appears that the Two Step Demand Charge would be better from a SGS/MGS seams perspective; this is something BCH should consider.	***Revised Response*** A transition from the Status Quo SGS energy rate to MGS at the seam (35 kW) would result in lower bills under all MGS alternatives; however, the degree to which the bill is lower differs between alternatives. • Under status quo rates, transitioning from SGS to MGS would result in a 8% lower bill at the seam. Comparatively: • Transitioning from SGS to the MGS alternative with Flat Demand Charge, Flat Energy charge would result in a 3% to 12% lower bill at the seam, for low to high load factor customers, respectively. The impacts are driven by both the different energy charges and a demand charge at T1. • Transitioning from SGS to the MGS alternative with Two Step Demand Charge, Flat Energy charge would result in a 16% lower bill at the seam. This is driven by the different energy charge.

2.	**BCUC staff** Why does BCH not have a preference for the Two Step Demand?	BCH has no identified preferred demand charge structure at this time and is soliciting feed-back. Both a Flat Demand Charge and a Two Step Demand Charge are used by other Canadian electric utilities. BCH is concerned that the Two Step Demand Charge does not have the same offset of bill impacts as the Flat Demand Charge for high load factor customers. In addition, a Flat Demand Charge better reflects costs which are flat.
3.	**BCUC staff** We see bill impacts as more of a transition issue and not a rate design issue.	BCH does not agree. Bill impacts have consistently been treated in rate design as a Bonbright customer understanding and acceptance rate design issue.
4.	**COPE 378** How are MGS customers charged for demand?	MGS customers are billed each month for the highest monthly peak. Individual MGS customer peaks may or may not be coincident with the system peak.
5.	**CEC** Is the demand charge monthly due to monthly billing?	The demand charge is expressed as $/kW/month and is billed monthly. The monthly demand reading is a reasonable proxy (and understandable for customers) for assigning customers their contribution of costs.
6.	**COPE 378** BCH should explore different demand charge approaches that better reflect contribution to coincident peak.	In Workshop 11B BCH will discuss a demand option like that of RS 1852 type demand charge with HLH concept which some have described as a Time of Use-like effect. In addition, BCH will be exploring demand ratchets.
7.	**AMPC** We caution that demand is not as simple as looking at a single coincident peak.	Agreed.
8.	**TransLink** Regarding slide 36, can BCH estimate the bill impacts for individual MGS customers?	At the May 2015 sessions described at page 4 of the Workshop 8A/8B Consideration Memo, BCH offered to estimate LGS and MGS customer bills for the SQ rates and alternatives using a simplified forecasting tool (the 'bill estimator'). BCH has used the bill estimator for TransLink accounts.
9.	**BCSEA** Does BCH have the absolute dollar impacts for illustrative bill impacts of both the Flat Demand and two Step Demand alternatives? Is it possible to produce graphs comparing cost causality and bill impacts? We ask because we want to know if the customers with bill impacts are those that drive demand costs.	Yes. This can be easily computed by applying the F2017 illustrative bills under status quo to the illustrative percentage variances of the alternative for each load-factor/annual consumption combination. The illustrative bills under status quo are located on slide 18 in the RDA Workshop 11 Appendix posted to the RDA website. No. The cost of service models and the rates models come from different and independent datasets, each drawn for their respective purposes. Note that costs are not simply driven by load factors and consumption of customer bills, but also by the coincidence factors. Since it is not practical to price rates using coincidence factors or load factors, there will naturally be some disparity between the annual allocators used to assign costs and the effectiveness of monthly customer bill determinants at revenue recovery.

10.	**COPE 378** Does BCH have an analysis with the number of customers impacted?	Yes; refer to the RDA Workshop 11 Appendix posted to the RDA website where the distribution is set out.
11.	**FNEMC** Is it possible to identify those low load factor customers that are worse off under the Flat Demand and Two Step Demand charge alternatives?	The impacted low load factor customers are very heterogeneous and include pumps, schools etc. Refer to the final slide of the RDA Workshop 11 Appendix posted to the RDA website, which has the SQ for each box for estimating bill impacts for these and other customers.
12.	**BCSEA** The very high load factor customers at the lower right hand side on slide 46 look like a separate population. Would segmenting these customers offer a potential solution?	Yes; many of these customers are migrating to the LGS rate class. No. BCH rejects segmenting GS customers on the basis of load factor for the reasons discussed earlier [Refer to Part 3, BCH responses to Q.7 and Q.9]. There is no logical end point to an exercise of creating rate classes or sub-classes for the purpose of mitigating bill impacts arising from rate restructuring. Each adversely affected member of a rate class would have the same basis for a further division of the class, potentially ultimately leading to a rate class for every customer. E3 found as part of its 2009 segmentation analysis that five GS classes were the most BCH could administer.
13.	**CEC** Does BCH agree that high load factor customers use the BCH system more efficiently?	Yes.
14.	**BCUC staff** Is it fair to summarize the two demand charge alternatives as follows: (1) the two alternatives are viewed by BCH about equally; (2) the Flat Demand Charge is better at bill impact offsetting; and (3) the Two Step Demand Charge may be better from a SGS/MGS seams perspective?	Not necessarily. Please see the response to Q.1, Section 5 above.

6. Presentation: Increasing Demand Charge Cost Recovery

Paulus Mau discussed how stakeholders suggested that BCH investigate increasing the MGS demand cost recovery of demand-related costs from the current 15%, and the results of increasing cost recovery to 35% using the MGS Flat Energy Rate with the Flat Demand alternative for illustration. Increasing the MGS demand charge cost recovery reduces bill impacts on MGS high load factor customers.

	FEEDBACK	RESPONSE
1.	**BCOAPO** What is the basis for the LRMC pricing of the SQ MGS two part rate?	The F2006 Call for Tenders, inflated.[4] F2016 MGS two-part baseline energy rate pricing is set out at page 25 of the Workshop 8A/8B Consideration Memo – the Part 2 LRMC based energy rate is 9.90 cents/kWh.

[4] For a summary of LRMC application to BCH rate structures, refer to slide 13 of the 'Introduction and Context' slide deck for Workshop 1; http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/rate-design-application-workshop-presentation-may8-2014.pdf.

2.	**BCSEA** We are concerned with the impact on the resulting MGS Flat Energy Rate if MGS demand fixed cost recovery is increased to 35% as shown on slide 48; the impact is more significant than increasing the SGS basic charge fixed cost recovery to 45%.	Agreed that there could be an increase in consumption. There is a trade-off between the Bonbright efficiency criterion and the customer understanding and acceptance and fairness criteria. BCH is concerned with the impact of the MGS Flat Energy Rate on MGS high load factor customers, and one mitigation measure is to increase the demand charge fixed cost recovery, which also aligns with the fairness criterion (fair apportionment of costs among customers).
3.	**BCUC staff** Will BCH model increasing cost recovery to 35% using the MGS Flat Energy Rate with the Two Step Demand alternative? Would BCH expect that increasing cost recovery to 35% using the MGS Flat Energy Rate with the Two Step Demand alternative would also soften the bill impacts on MGS high load factor customers?	Yes. BCH may be able to present these modelling results at the 30 July 2015 wrap-up workshop and/or the Workshop 11A/11B Consideration Memo. Yes.

7. Presentation: Two Potential MGS Phase-in Options

Paulus Mau introduced two high-level MGS phase-in options: (1) a 3-year period; and (2) using a 10% bill impact cap. BCH prefers the 3 year phase-in approach for the reasons set out in slide 54.

	FEEDBACK	RESPONSE
1.	**AMPC** What happens to revenues if the 10% bill impact cap is used? Is there lost revenue?	All designs are revenue neutral to the status quo rate. That is, all alternatives are priced to recover the same revenue as the status quo for each of the years simulated, including years during the phase-in period. That is, the rates will incrementally flatten so that the most adversely impacted customer will have a maximum bill impact of 10%, while remaining revenue neutral to the status quo.
2.	**BCOAPO** On slide 57, how many customers have bill impacts over 10%? What is the maximum bill impact under the 3 year phase in option?	For F2017, BCH forecasts about 55 accounts with bill impacts greater than 10%. The customer with the highest bill Impact, calculated as the per cent bill difference between F2016 and F2017, is 31% ($150) The maximum bill impact customer, calculated as the 3-year cumulative per cent bill difference between F2016 and F2019, has a bill impact of 93% ($456).
3.	**FNEMC** For smaller MGS customers, what is the absolute bill impact under the 3 year phase in option?	Please refer to slide 18 of the RDA Workshop 11 Appendix posted to the RDA website, which has the SQ for each box for comparison; this allows readers to do their own calculations. For the most adverse customer with the highest bill impacts on a percentage basis, see response to BCOAPO above.
4.	**BCSEA** Does BCH have any customer input as to whether a quicker – say 1 year – phase-in period is preferred?	Phase-in requests have come from customers whenever a rate structure is changed. The 3 year period is consistent with 2007 RDA and 2009 LGS Application proposals.
5.	**BCOAPO** Has BCH investigated a 'middle ground' between the 3-year period phase-in and the 15+ years required under the 10% bill impact cap option?	Not to date. The 3-year period was chosen on the basis of the 2007 RDA and 2009 LGS Application proposals.

6.	**BCUC staff** Bill impacts alone should not drive rate design. Here we have about 350 customers, out of a total of about 17,000 for the MGS rate class, with 10% bill impacts.	
7.	**COPE 378** If BCH pursues the MGS Flat Energy Rate, to what extent would it simply reverse the bill impacts arising from the 2009 LGS Negotiated Settlement?	The impacts are not comparable. There would be no reversing of effects if BCH pursues the MGS Flat Energy rate, as the energy rates were not flat prior to 2009 but rather were a declining block structure. Rate shaping of the Part-1 energy charges toward a flat rate was part of the 2009 LGS Negotiated Settlement, subject to a maximum bill impact of 5% above the class average rate change. The 2009 LGS Negotiated Settlement resulted in a transition focused on introducing the two part energy rate with a baseline to the MGS class. Changes to the demand rate structure were not part of the 2009 LGS application.
8.	***Closing Comments***	
Anne Wilson thanked everyone for making the time to participate in the workshop and reminded participants that Workshop 11B addressing LGS rate issues would be held tomorrow, 26 June 2015. Meeting adjourned at 11.45 am.		