Section:	Tab 4	**Page No.:**	Page 10
Topic:	DSM		
Subtopic:	10 Year Cost Flow Update		
Issue:			

PREAMBLE TO IR (IF ANY):

Figure 4.10 on page 10 indicates that $26.3 million is to be spent on "added conservation rates for residential and commercial customers" and that $55.1 million will be spend on "added fuel choice program" during the 10-year period 2015 - 2024.

QUESTION:

Please indicate the status and objectives the Conservation rates initiative, and a breakdown of the proposed spending for residential and commercial customers. Specifically what is the $26.3 million being spent on?

RATIONALE FOR QUESTION:

MIPUG to review DSM programming generally regarding the rate impacts, especially to GSL customers where possible.

RESPONSE:

The program design details of the Energy Conservation Rates initiative which were included as part of Manitoba Hydro's 2014 – 2017 Power Smart Plan – 15 Year Supplemental Report (included as Appendix 8.1 of this Application) are not finalized nor approved at this time. For purposes of planning, a placeholder for the program was included in Corporation's overall Demand Side Management Plan. The placeholder included a high level estimate for costs, energy savings and timing.

The objective of the Energy Conservation Rates initiative would be to optimize the use of all available tools in achieving the Corporation's overall demand side management strategy. In developing the Corporation's 2014 – 2017 Power Smart Plan, an aggressive approach was contemplated which went much beyond the traditional approach used to date involving primarily incentives, education and codes to influence customers. Under the 2014 – 2017 Power Smart Plan, a strategy was envisioned for leveraging and optimizing the use of all available tools in program designs including the use of incentives, education, conservation rates, service extension policies, etc. For example, alternative program designs for the new home market are being considered which range from one design premised upon significant upstream incentives to another design premised upon a combination of changes to service extension policy and service extension allowances.

Detailed work on these program designs is pending a Government decision on Manitoba Hydro's future role and responsibilities for Demand Side Management.

Section:	MIPUG/MH I-3	**Page No.:**	
Topic:	DSM Programming		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please confirm MIPUG's understanding that the pursuit of residential conservation rates will drive Present Value costs to Hydro of $12.6 million and lost revenues of $139.7 million (a combined $152.3 million adverse financial impact) for present value benefits of only $117.0 million, a net loss of $22.7 million. Please provide the time horizon over which the Present Value of net impacts is expected to occur.

RATIONALE FOR QUESTION:

MIPUG to review DSM programming generally regarding the rate impacts, especially to GSL customers where possible.

RESPONSE:

b) In Manitoba Hydro's proposed Energy Conservation Rate program, the intent is to design rates such that the Energy Conservation Rate program is revenue neutral. As such, there will be no expected lost revenue associated with the program. As an integral component of the Program design under this premise (i.e. revenue neutrality), overall rates will effectively and inherently need to be increased to offset for any lost revenue associated with consumers using less energy. Under these assumptions, the NPV of the Energy Conservation Rate program is $104.4 million ($117 million - $12.6 million).

For the purposes of calculating the RIM associated with the Program, it is assumed that there will be lost revenue and a RIM of 0.8 is calculated. If rates weren't effectively increased to meet the "revenue neutral" assumption, then the NPV of the Energy Conservation Rate Program would be a net loss of $35.3 million ($117 million - $12.6 million - $139.7 million).

Section:	9 Figure 9.3, P.7	Page No.:	PUB/MH I-55
Topic:	Energy Supply		
Subtopic:	DSM Impacts		
Issue:	Changes to DSM Load Reductions		

PREAMBLE TO IR (IF ANY):

In PUB/MH I-55, Manitoba Hydro provides a comparison between DSM savings included in the Level 2 DSM option discussed during the NFAT and projections in the 2014 Power Resource Plan.

QUESTION:

b) Please explain the factors behind delaying the launch of the of fuel choice programs to 2017/18?

c) Please explain the factors behind delaying the introduction of conservation rates to 2017/18

RATIONALE FOR QUESTION:

RESPONSE:

As outlined in Manitoba Hydro's response to PUB/MH-I-55, the NFAT Update Level 2 DSM savings were created as part of a sensitivity run for the NFAT hearing. At that point, none of the DSM options were formally approved as the Corporation's DSM plan.

Subsequently, the Corporation developed its 2014 Power Smart Plan in consultation with the Minister responsible for Manitoba Hydro in accordance with the Energy Savings Act. The timing and level of DSM energy savings included in the Plan were based upon more detailed and refined program designs and upon the outcome of consultations with the provincial government.

Discussions on the merits and issues associated with contemplated Conservation Rate initiatives were not held with the Provincial Government at that time as Manitoba Hydro needed to undertake further study and analysis. To allow for this work to be undertaken, the timing of the Conservation Rate initiatives was deferred to 2017/18.

Discussions with the Provincial Government on the merits and issues associated with pursuing a Fuel Choice Program concluded with Manitoba Hydro taking an educational campaign approach in pursuing the opportunities associated with fuel choice.

Section:	6	**Page No.:**	6 of 21, Appendix 6.12
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Limited Use of Billing Demand		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is proposing to increase the basic charge for this rate class to the same level as for regular GS Small/Medium customers, set the demand charge at approximately 25% of the general demand charge, and base the energy charge on achieving revenue neutrality at a load factor of approximately 18%.

QUESTION:

Provide a table comparing the existing rate items (basic charge, demand charge, energy charge) for the LUBD rate against the ones applied for, indicating percentage changes.

RATIONALE FOR QUESTION:

Manitoba Hydro has applied for changes to the LUBD rate.

RESPONSE:

The table on the following page provides the current and proposed rates for the LUBD rate classes.

The rates proposed for LUBD customers are derived from the rates proposed for General Service Small, Medium and Large customer classes. The monthly Basic Charge is the same as proposed for the regular GS Small/Medium customer classes. The Demand Charge is set at approximately 25% of the proposed Demand Charge of the corresponding regular General Service class, with the Energy Charge calculated to provide revenue neutrality at a load factor of approximately 18%.

Manitoba Hydro notes that, in the table below, the percentage increase in the demand charge is reflective of the rounding that occurs in calculating the demand rate. For example, the LUBD Small and LUBD Medium Demand Charge is determined by taking 25% of the proposed GS Small and Medium Demand Charge and then rounding to two decimal places. The April 2015 demand charge is $2.3625 which rounds to $2.36. The April 2016 demand charge is calculated as $2.4558 which rounds to $2.46. At four decimal places, the percentage change is 3.95%, whereas the rounded amounts indicate a 4.24% increase.

		Current Rate	**Proposed April 2015**	**% Change**	**Proposed April 2016**	**% Change**
LUBD Small:	Basic Charge 1 Ph	$19.73	$20.51	3.95%	$21.32	3.95%
	Basic Charge 3 Ph	$27.82	$28.92	3.95%	$30.06	3.94%
	Energy Charge	$0.08795	$0.09146	3.99%	$0.09502	3.89%
	Demand Charge	$2.27	$2.36	3.96%	$2.46	4.24%
LUBD Medium:	Basic Charge	$29.36	$30.52	3.95%	$31.73	3.96%
	Energy Charge	$0.08795	$0.09146	3.99%	$0.09502	3.89%
	Demand Charge	$2.27	$2.36	3.96%	$2.46	4.24%
LUBD Large 750-30 kV:	Energy Charge	$0.07788	$0.08095	3.94%	$0.08417	3.98%
	Demand Charge	$1.93	$2.01	4.15%	$2.09	3.98%
LUBD Large 30-100 kV:	Energy Charge	$0.06915	$0.07190	3.98%	$0.07471	3.91%
	Demand Charge	$1.65	$1.72	4.24%	$1.79	4.07%
LUBD Large >100 kV:	Energy Charge	$0.06381	$0.06653	4.26%	$0.06914	3.92%
	Demand Charge	$1.50	$1.53	2.00%	$1.59	3.92%

Section:	6	**Page No.:**	6 of 21, Appendix 6.12
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Limited Use of Billing Demand		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is proposing to increase the basic charge for this rate class to the same level as for regular GS Small/Medium customers, set the demand charge at approximately 25% of the general demand charge, and base the energy charge on achieving revenue neutrality at a load factor of approximately 18%.

QUESTION:

For the customers shown in Table 5 of Appendix 6.12 that would qualify for the proposed Time-of-Use rates if implemented, please indicate the benefit, if any, those customers could realize if they switched to TOU.

RATIONALE FOR QUESTION:

Manitoba Hydro has applied for changes to the LUBD rate.

RESPONSE:

Of the customers shown in Table 5 of Appendix 6.12 that would qualify for the proposed Time-of-Use (TOU) rates, none would benefit if they switched to TOU.

For purposes of comparison between rate options, the actual energy and demand incurred by these customers in 2013/14 was used to calculate the annual costs under proposed LUBD and TOU rates for April 1, 2016. Based on their energy consumption from that year and applying the proposed April 1, 2016 rates, the revenues generated would be $145,391 on LUBD and $160,628 on TOU.

Section:	Tab 4	**Page No.:**	10-12
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Spending for System Extensions		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the response to part (a) is affirmative:

i. What is Manitoba Hydro's policy with respect to requiring capital contributions from customers in such circumstances?
ii. What assumptions has Manitoba Hydro made regarding customer capital contributions associated with CEF14 and what was the basis for these assumptions?
iii. How are such contributions treated in CEF14 and IFF14?

RATIONALE FOR QUESTION:

The information request seeks to better understand the basis for Manitoba Hydro's Sustaining Capital Expenditures related to system expansion/new customers.

RESPONSE:

Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either the specified investment allowance (in the case of residential customers) or the amount of investment allowance as determined by a revenue test (in the case of General Service customers served at voltages less than 30 kV). General Service customers requiring service at voltages greater than 30 kV, or any new General Service load greater than 5 MW, contribute to the full cost of the dedicated service extension facilities and capacity additions to the common integrated system, if required.

Generally, contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

Section:	Tab 6 Tab 6: Appendix 6.10	**Page No.:**	14 5
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Change in Peak and Off-Peak Definitions		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm what the current Peak and Off-Peak period definitions are as used for the CRP.

RATIONALE FOR QUESTION:

Clarify what the change in definition of peak and off-peak is and the basis for the change.

RESPONSE:

The current Peak and Off-Peak periods for the CRP are defined as follows:

Peak:	7:01 to 23:00 Monday to Sunday inclusive
Off-Peak:	23:01 to 7:00 Monday to Sunday inclusive

Manitoba Hydro is proposing to modify the Peak and Off-Peak periods for the CRP to be defined as follows:

Peak:	6:01 to 22:00 Monday to Friday inclusive excluding Statutory holidays
Off-Peak:	22:01 to 06:00 Monday to Friday inclusive, and all hours from 0:01 to 24:00 on Saturday, Sunday and Statutory holidays.

These proposed periods are intended to conform with the periods for On-Peak (5 days X 16 hours) and Off-Peak hours (the balance of all remaining hours) as defined in the MISO market (balance of hours).

Manitoba Hydro is also proposing to structure its Time-of-Use Rate for GSL > 30 kV customers in the same manner, to ensure that these rate designs are reflective and consistent with the time periods experienced in the MISO market.

Section:	Tab 7 Tab 7: Appendix 7.1	**Page No.:**	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

Is the introduction of TOU rates for large customers in 2016/17 expected to have any impact on the load forecast? If not, explain why not? If yes, has any such impact been incorporated in the current forecast?

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

The introduction of Time-of-Use rates for large customers in 2016/17 is not expected to have a material impact on overall energy consumption by these customers in the short term due to the rate neutral implementation planned for these rates.

In the long term, customers may adapt their operations to respond to the price signals provided through the rate structure or capture potential benefits within the rate structure. Some customers may seek to expand their participation in Manitoba Hydro's Industrial Power Smart Programs in an effort to reduce the consumption of higher cost on-peak energy. Conversely, some customers may seek to increase consumption of off-peak energy to expand production or shift energy requirements to lower cost off-peak rates, but load shifting will have no material impact to overall energy consumption.

In most instances, increased consumption during the off-peak period will require customer investment in infrastructure and processes that will provide Manitoba Hydro with sufficient lead time to incorporate potential load changes into future load forecasts. In any instance, such increases are not anticipated to significantly change the long-term forecast.

Section:	Tab 8: Appendix 8.1	Page No.:	14
Topic:	Demand Side Management		
Subtopic:	Industrial Programs		
Issue:	TOU Rates and Conservation Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Why are "conservation rates" planned for Residential and Commercial customers but not for Industrial customers?

RATIONALE FOR QUESTION:

There are no new conservation rates for industrial customers planned for the period 2014/15 to 2028/29

RESPONSE:

Manitoba Hydro is proposing a Time-of-Use ("TOU") rate design for the GSL > 30 kV customer classes because this rate design provides a more appropriate price signal for large energy consumers, than the current single block rate design. The TOU rate design provides specific price signals that are differentiated by the time of day (on-peak hours and off-peak hours) and the season in which that energy is consumed.

The higher on-peak values for energy reflect the higher demand for energy during these periods and the role that on-peak customer demand plays in the need for generation and transmission resources. It is anticipated that the higher winter season and on-peak rates will encourage customers to more actively manage energy consumption during these higher demand periods, as the rate will provide a stronger price signal than the present single block rate provides.

The differentiation in price between on-peak and off-peak consumption will provide an economic incentive to customers to shift their energy usage away from the on-peak time period. Customers that are able to accomplish this type of load shift might not reduce their overall quantity of energy consumed, but they will consume energy in a more economically efficient manner for themselves and for Manitoba Hydro.

Some customers may not be able to shift portions of their load away from the on-peak period. In those circumstances, the higher on-peak price may provide more economic incentive to find means to reduce their energy consumption in the on-peak period.

Manitoba Hydro's Industrial Power Smart Programs will support customer efforts to manage their on-peak consumption with comprehensive technical and financial support. The anticipated conservations savings from those efforts are captured in the DSM targets identified for Manitoba Hydro's industrial demand-side management programs.

Section:	Tab 8: Appendix 8.1	Page No.:	14
Topic:	Demand Side Management		
Subtopic:	Industrial Programs		
Issue:	TOU Rates and Conservation Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

The TOU rates proposed for large industrial customers are not referenced in the Power Smart Plan. Why are such rates not considered to be part of the Power Smart activities when future Conservation Rates for Residential and Commercial are?

RATIONALE FOR QUESTION:

There are no new conservation rates for industrial customers planned for the period 2014/15 to 2028/29

RESPONSE:

Please see the response to COALITION/MH-I-70 a.

Section:	Appendix 5.5	Page No.:	
Topic:	OM&A Cost Containment		
Subtopic:	BC Hydro Review Report		
Issue:			

PREAMBLE TO IR (IF ANY):

During the 2012/13 & 2013/14 GRA Hydro filed Exhibit #28, which included a report detailing the response and action plan for Manitoba Hydro's comments on the recent BC Hydro Review report examining the operating and capital requirements of BC Hydro for the purpose of minimizing rate increases.

QUESTION:

Can Hydro provide a status update including a timeline for when the other action plan items will occur (or alternatively indicate which of the other Action Plan items detailed in this report will not proceed)?

RATIONALE FOR QUESTION:

MIPUG plans to review Hydro's approach to budgeting and cost control methods.

RESPONSE:

As noted in the preamble to the question, Manitoba Hydro Exhibit #28 from the last GRA included a report that provided Manitoba Hydro's comments with respect to the 2011 BC Hydro review.

While it was never the intention that Manitoba Hydro would have detailed action plans surrounding all of the recommendations in response to the review of BC Hydro, Manitoba Hydro provides the following update on a number of the initiatives that are ongoing at the Corporation, that are relevant to its current operations.

Action Plan #1:

The cost constraint measures currently in place for operating and administrative expenses will be maintained with regular updates provided to the Board. In addition, a review will be undertaken to determine what steps can be taken to further constrain operating and administrative expenses. This review will also be expanded to include capital expenditures. Further, technology will be leveraged to further increase the productivity and efficiency of the Corporation.

Status:

Please see Tab 5, section 5.14, pages 45-51 for a description of the key ongoing initiatives being undertaken by the Corporation to manage its overall operating and capital expenditures. Also see the response to MIPUG/MH I-38a for a summary of the process undertaken by Manitoba Hydro to review its staff complement that resulted in a projected reduction of 300 operational positions over the next 3 years.

Action Plan #2:

Investigate whether cost reductions can be achieved through increased use of external resources.

Action Plan #6:

Consider the use of private sector contractors in ongoing efforts to effectively manage overtime and other costs.

Status:

Manitoba Hydro continuously reviews opportunities to utilize external resources including private sector contractors to either reduce operating costs or optimize the use of its capital funding in light of its need to manage its capital asset growth. The use of external engineering firms and construction contractors helps to manage work schedules more effectively and deliver in-service dates on time and on budget.

For example, urban substation projects in Winnipeg and a number of transmission station projects in Manitoba are now primarily contracted out on an Engineering, Procurement (EP) model or on an Engineering, Procurement and Construction (EPC) basis in order to address resource limitations, streamline engineering and construction processes and take advantage of economies of scale.

Action Plan #3:
Establish an Information Technology Coordinating Committee at the Corporate level to confirm that all Information Technology projects are fully aligned with strategic objectives.

Status:
The Corporate IT Coordinating Committee (Corporate ITCC) has been established and includes representatives from each Business Unit as well as Information Technology Services.

The Corporate ITCC coordinates the efforts of enterprise IT projects, on behalf of all business units and to ensure that there is appropriate communication and that the enterprise IT projects are prioritized according to overall corporate goals.

Action Plan #4:
Undertake a comprehensive supply chain management and logistics review (including upstream and downstream processes).

Status:
Please see Tab 5, section 5.14, subsection 5.14.9, page 50, for a description of its Supply Chain Management initiatives.

Action Plan #5:
In consultation with unions, continue with ongoing efforts to reduce the overall cost of operations and further improve productivity.

Status:
Manitoba Hydro continues to work with its unions towards improving the cost of operations and productivity. Examples of where this has been successfully achieved include reducing the amount of overtime paid to employees when resolving technical issues over the phone, reducing service hours where appropriate and working closely with the affected unions on the consolidation of staff due to district reorganizations.

In addition to the above, Manitoba Hydro continues to explore future opportunities where costs savings or productivity enhancements can be realized. It should be noted that any changes will require dialogue and agreement with the unions prior to implementation.

Action Plan #7:

Further review employee benefit costs to confirm that costs are being effectively incurred to attract and retain talented employees at Manitoba Hydro.

Status:

Manitoba Hydro has or is in the process of undertaking various initiatives to ensure that benefits costs are being effectively incurred. Examples include:

- Manitoba Hydro's Employee Assistance Program – In November 2012, a review of market competitiveness and best practices was completed and recommendations were provided. In April 2013, Manitoba Hydro initiated a change to the delivery model of the Employees Assistance Program, resulting in cost reductions and overall improvements to service delivery.

- Health Benefit Program Administrative Costs – In December 2012, Manitoba Hydro initiated a review of the administrative fees associated with health benefit programs. This was done to ensure financial market competitiveness from Manitoba Hydro benefit service providers. The review concluded that most administrative fees associated with health benefit programs benefit were competitive, with recommendations for improvements on a few benefits. As a result of these recommendations, Manitoba Hydro reopened two contracts with benefit providers, resulting in administrative fee costs savings.

Action Plan #8:

Consider the merits of a variable pay for performance incentive program for management and professional staff.

Status:

Manitoba Hydro has not considered broadly the merits of a variable pay for performance incentive program for management and professional staff.

Action Plan #9:

Review budgeting and forecasting processes to ensure that all programs are cost-justified and that appropriate measures are in place to ensure the cost effectiveness of operating and maintenance expenditures.

Status:

As part of the IFF14 operating budget process, Manitoba Hydro identified additional measures to manage OM&A expenditures below inflationary levels. The forecast apportioned to each of the business units considered specific business and economic factors, as well as the various measures needed to support cost containment.

In evaluating the appropriateness of the business unit targets an analysis of specific work functions was undertaken, seeking opportunities to streamline processes through the use of technology and consolidation or elimination of work, while balancing the need to ensure staffing levels are adequate to provide safe and reliable service.

Action Plan #10:

Examine the concept of requiring a commitment from staff to remain with Manitoba Hydro for a minimum of five years after obtaining apprenticeship training.

Status:

Manitoba Hydro is examining the concept of retaining Power Line apprentices through "Continue to Work" commitments and is conducting research on best practices at other utilities. Preliminary information indicates that programs of this kind are rare in the electrical industry. Further review is required to see if such a program is feasible for Manitoba Hydro, including discussion with affected bargaining units.

Action Item #11:

Investigate the extent to which increased value can be derived from expanding the use of innovative approaches to constructing major capital projects.

Status:

Manitoba Hydro evaluates the various project delivery models when determining how to execute a project. Evaluations are done on a project by project basis and consider a number of factors such as safety and reliability constraints to determine whether internal delivery models or contracting models are most effective. For example, following the Jenpeg unit #1 electrical fire, a turnkey project delivery model was used to significantly accelerate the tendering process and is anticipated will return the unit to service approximately 1 year earlier than design-bid-build model.

Examples of project delivery models include Design-bid-build, Engineering Procurement (EP), Engineering, Procurement and Construction (EPC), etc.

Action Item #12:
Research whether further savings can be realized by providing more flexibility to vendors and contractors to achieve project deliverables.

Status:
Please see Tab 5, section 5.14, subsection 5.14.3, page 46, for descriptions of the actions that Manitoba Hydro has undertaken to manage contractor costs for capital projects.

Action Item #13:
Formalize the use and reporting of project contingencies and segregate contingencies as identifiable components of projects.

Status:
Major New Generations and Transmission projects apply management reserves to properly address both labour and cost escalation risks based on current market conditions and labour restrictions.

For other large projects, progress is being made on formalizing the use and reporting of project contingencies and segregating contingencies as an identifiable component. The amount of contingency can range from 5% to 15% of the overall project cost, and is based on the complexity of the project and identified risks. The risks are ranked by probability and consequence to determine an appropriate level of contingency.

Action Item #14:
Review policies and processes related to First Nation consultations and environmental assessments with a view to reducing these costs.

Status:
Since the review of BC Hydro took place (2011), the landscape regarding Aboriginal relations has significantly changed. There have been a number of court decisions during this time period, such as the recent Tsilhqot'in decision, which have influenced Aboriginal perspectives on a number of matters, including how they wish

to be engaged and involved in projects. This constantly changing landscape results in regular review of processes related to Aboriginal engagement.

Efforts have been made to streamline and improve Aboriginal engagement including:

- Initiating engagement with communities earlier in the process to increase opportunities for communities to learn about the project, share concerns, and provide input into routing decisions;
- Working closely with communities in the development of project-related traditional knowledge studies;
- As early as possible, sharing information from Aboriginal engagement with the Crown as appropriate and agreed-to by communities, with the intent to assist in improving the efficiency and timeliness of any Crown Consultation processes undertaken by the Provincial or Federal governments.
- Reviewing and adjusting communication processes with communities to ensure adequate and timely information sharing with respect to project planning and construction.

It is anticipated that the above actions may increase the ability to mitigate or address concerns through routing or project design, increase transparency with respect to how concerns have been addressed, and reduce the number of concerns, raised during or after regulatory processes have occurred.

Action Item #15:

Provide updated recommendations to the Manitoba Hydro Board on rate design objectives that continue to balance the criteria of energy efficiency, fairness, competitiveness, simplicity, and appropriate cost recovery (among other criteria) that meet the criteria of efficiency, fairness, competitiveness and simplicity.

Status:

Pleaes see Tab 6, section 6.3, pages 7 to 13 for a description of Manitoba Hydro's Time-of-Use Rates proposal for General Service Large. Manitoba Hydro is seeking approval to implement a new Time-of-Use rate design for its large energy consumers. Manitoba Hydro notes that the review of this rate design proposal has been postponed, and is to be addressed in conjunction with the Cost of Service review.

Action Item #16:

Provide an updated Cost of Service Study to the Manitoba Hydro Board that incorporates updated rate design objectives.

Status:

Please see Tab 6, section 6.5, page 15, for a description of the Cost of Service Stakeholder Engagement process undertaken by Manitoba Hydro.

Action Item #17:

Conduct a review and provide recommendations on the appropriate capital structure for Manitoba Hydro during the period of the major capital expansion program.

Status:

Please see Tab 3, section 3.4, subsection 3.4.1, page 11 for a discussion of the financial target review which is underway, as well as the response to PUB/MH I-84d for the associated terms of reference.

Section:	Tab 6	Page No.:	Page 11
Topic:	Rate Changes		
Subtopic:	Demand Ratchet changes		
Issue:			

PREAMBLE TO IR (IF ANY):

In Board Order 18/15 the Board made the following comments with regards to scope of the GRA:

"The Board has determined that it will examine Manitoba Hydro's time-of-use rate proposal at the cost of service review to take place later this year, and not at this GRA. Accordingly, the Board will not entertain a review, by Interveners, of time-of-use rates in this proceeding."

QUESTION:

Based on Order 18/15 please confirm Hydro intends for that the proposed changes to the demand ratchet levels for customer classes GSL 30-100kV and GSL>100kV to be reviewed with the time-of-use rates at the cost of service review to take place later this year, and not at this GRA.

RATIONALE FOR QUESTION:

To clarify what rate changes should be reviewed in this GRA compared to what should be reviewed in the Cost of Service hearing.

RESPONSE:

Confirmed.

PUB/MH I-149

Reference: Appendix 10.2 MH Inverted Rates Plan of Action

Please indicate MH's intentions in the 2012 GRA for pursuing inverted rates in any or all classes.

ANSWER:

Manitoba Hydro has not advanced a plan to implement inverted rates in the current GRA.

With respect to the Residential class, while Manitoba Hydro had inverted rates from 2008 to 2010, the PUB has made clear that any further proposal for inverted rates in the future should make accommodation for those who may be adversely affected by inverted rates, such as those who do not have a choice in their primary heat source (i.e. lack of access to natural gas service). Manitoba Hydro continues to review this topic but to date has no formal timetable as to an inverted rate structure for residential customers.

PUB/MH II-101

Reference: PUB/MH I-149 Inverted Rates Alternative

a) Please provide an outline of the alternative residential rate strategies that MH is considering with respect to customers whose primary heat source (no access to natural gas) is electrical.

ANSWER:

Manitoba Hydro reviews potential residential rate strategies from time to time, including inverted rate strategies. Manitoba Hydro's Residential energy rate proposed for implementation April 1, 2013 is 7.2 cents per kW.h which is 85% of the marginal cost value (8.52 cents per kW.h) in the current Power Smart plan and higher than current short run marginal cost.

Other jurisdictions, such as BC Hydro, have recently introduced inclining block rates to replace the single rate schedule for residential customers with the objective of encouraging conservation by reflecting the legacy cost of energy in the first block and the marginal cost of new energy in the second. Price elasticity for electricity in the residential sector is traditionally low therefore requiring a substantial differential to effect a marginal change.

While not under active consideration by Manitoba Hydro at this time, if it were desired to implement inverted rates to the Residential class and to differentiate application of such rates between customers with electric heat and customers with other sources of space heating, the following alternatives may be considered:

- Seasonal differentiation of first block size such that more energy would be billed at a lower rate during the winter heating months
- Differentiating application of Residential rates between electrically heated customers and those with other space heating fuels.
- Special rates for customers where natural gas is not available.

The main goal of any strategy to re-design electricity rates for the Residential class is to balance the competing objectives of sending an appropriate price signal to encourage efficient choices by customers and mitigating impact of future rate increases on specifically electric heat customers. Revenue neutrality, customer acceptability, administrative cost and burden, gradualism and conformity to Uniform Rate Legislation are other factors to be considered.

1) <u>Seasonal Differentiation of First Block Size</u>

This method increases the size of the first block for the winter months (November through April inclusive) and reduces the block size for the summer months (May through October). For example, the summer season inversion could be set at 500 kWh per month while the winter season could be set at 1000 to 1500 kWh per month.

The advantage of a seasonally differentiated first block size is mitigation of impacts on winter bills for those who have no choice but to use electricity to heat their homes. This method does not distinguish between residential customers who are coded as standard (non-electric) or all-electric and so avoids the administrative difficulties inherent in maintaining a separate classification of residential customers based on their heating fuel.

In terms of customer impacts, the winter bill advantage may be offset, at least in part, by higher summer bills. Further, because the larger winter first block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, this is the easiest strategy (other than the status quo or a similar approach) to implement and perhaps the easiest for customers to understand. All residential services would be affected with two rate changes a year. Billing issues through a rate change month would, however, be magnified as customers would look more closely at bills and would therefore be more apt to contact the Customer Contact Centre and/or their district office with inquiries. The major complaint would be unfairness of estimated bills and proration.

A more complex variant would be to add one or two additional seasons with first block size set mid way between the winter and summer rate structure; these would apply during the shoulder months of March, April, May, September, October and November.

2) <u>Different application of Rates for Standard and All-Electric Customers</u>

This method is similar to 1) above except that only those customers coded on the Billing System as all-electric would be eligible for the seasonal block rate. Standard customers would not have any seasonal differentiation. Expanding on this method, monthly block sizes could be based on monthly heating degree days. For example, the monthly block could rise gradually starting in October with each month increasing until the maximum block size is reached in January/ February, decreasing gradually thereafter.

The major advantage of this method is that it will expose a larger number of customers and kWh to the higher second block price, than the method which does not distinguish between standard and all-electric customers. However, differentiating rates solely upon heating source may encourage customers to make less optimal heating fuel choices.

Should this method be considered, new billing/customer codes would need to be created to more accurately identify electrically heated customers. Identifying customers with electric heat has been done, but it is a manual process and is primarily based upon customers self-declaring their heating fuel choice or where available evidence demonstrates the heating fuel source (e.g. permit information). Variable blocks, based on heating degree days, are likely to lead to considerable customer confusion and increased calls to the Contact Centre and district offices, especially with estimated billings. Varying monthly blocks would also complicate adjusted billings for periods greater than one month.

One important factor to note is that this method may be perceived as not conforming to the principles of uniform rates, even though the separate electric versus standard heating rate classes would apply across the province. Customers would be discriminated against based on the type of heating they chose to use to heat their homes. More seriously, there is also the potential for customers to choose electric heating in order to benefit from the better rate, thereby increasing demand on the system, which in turn will result in higher rate increases to all customers.

3) <u>Different Rates Based on Fuel Availability.</u>

Similar to the second method above, this method would apply seasonal blocked rates based on availability of alternate heating fuels. Only those customers who do not have access to gas service would be eligible for a larger seasonal block. Customers in areas served by natural gas either would not get a seasonal block charge or would have a lower block kWh amount per month. This method also has the advantage of exposing a larger number of customers and kWh to the higher second block price, particularly during the winter, than the method which does not distinguish between standard and all-electric customers.

Notwithstanding these advantages, this method is judged to be the least appropriate approach to recognizing electric heat requirements. It is administratively difficult to specifically identify areas served and not served by gas, as boundaries and proximity to natural gas are continually changing. Further, the costs associated with conversion to natural gas heating even in areas where natural gas is available can be a significant burden for customers. Alternatively, one could distinguish between existing and new electrically heated homes within areas served by natural gas, although this could add significantly to administrative complexity. This method would also require legislative change, as it would clearly violate existing uniform rates legislation.

GAC/MH I-5

Subject: Seasonal Pricing

a) Please indicate whether MH has considered proposing seasonally-differentiated rates for Residential and General Service non-demand rates

i) If not, explain why not.

ANSWER:

The following was provided in the last General Rate Application hearing in response to RCM/TREE/MH I-8(f):

Manitoba Hydro has done some preliminary review of seasonally-differentiated rates for the Residential rate class. One method looked at increasing the size of the first block rate in the winter months and reducing the first block size in the summer months. This method would have the advantage of mitigating impacts on winter bills for those customers who have no choice but to use electricity to heat their homes.

In terms of customer impacts of a seasonally differentiated rate, the winter bill advantage would be offset, at least in part, by higher summer bills. Further, because the larger winter block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, implementing a seasonally-differentiated rate is more complex than the current rate structure. However compared to other potential TOU rate structures it is relatively easy to implement and for customers to understand. All residential services would be affected with two rate changes a year. Billing issues could be problematic for customers in the two rate change months as customers may notice the billing difference and would be more apt to contact the Contact Centre and/or their district office with enquiries. The major complaint would be unfairness of estimated bills and proration of bills.

GAC/MH I-5

Subject: Seasonal Pricing

b) Please indicate whether MH has considered proposing seasonally-differentiated rates for the General Service Small and Medium demand rates.

i) If not, explain why not.

ANSWER:

Manitoba Hydro has not formally considered seasonally-differentiated rates for the General Service Small and Medium demand rates. Customers in these classes cover a wide spectrum of diverse business types, all of which operate in different manners. Trying to design a rate that would recover costs while taking account of different customer impacts would be challenging, given this diversity. This may be an area worth exploring if and when Manitoba Hydro has gained some experience with TOU rates for the General Service Large customer classes > 30 kV.

GAC/MH I-5

Subject: Seasonal Pricing

c) Please provide all available analyses of the costs and benefits of implementation of seasonal pricing.

ANSWER:

Manitoba Hydro had not preformed a formal analysis of the cost and benefits (if any) of implementing seasonal pricing for Residential and Small / Medium General Service customers.

GAC/MH I-8

Subject: Rebalancing Energy and Demand Charges
Reference: Tab 10 - Proposed Rates and Customer Impacts

a) Please explain whether Hydro accepts in principle collecting some demand-related costs in a peak period energy charge rather than a demand charge.

ANSWER:

Manitoba Hydro has previously indicated that it could support collecting some demand related costs in a peak period energy charge. Please find pages 54 through to 56 of Manitoba Hydro's Rebuttal Evidence filed on February 28, 2008 attached.

MANITOBA HYDRO
INCREASE ELECTRIC RATES FOR 2008/09

REBUTTAL EVIDENCE

(1400 kW.h Block)

KW.H	MARCH 1, 2007 $ / MONTH	APRIL 1, 2008 $ / MONTH	DIFFERENCE IN $ / MONTH	PERCENT CHANGE
250	$20.98	$19.69	($1.29)	-6.15%
750	$49.93	$49.59	($0.34)	-0.68%
1 000	$64.41	$64.54	$0.13	0.20%
2 000	$122.31	$126.14	$3.83	3.13%
5 000	$296.01	$314.54	$18.53	6.26%

RATE DESIGN; GENERAL SERVICE CLASSES

This section deals with the General Service rate design evidence provided by Paul Chernick on behalf of Resource Conservation Manitoba / Time to Respect Earth's Ecosystems ("RCM/TREE"). Specifically, it will deal with: Demand Charges and Ratchets; Mr. Chernick's specific recommendations for General Service Small and Medium for April 1, 2008; and Time of Use ("TOU") Rates.

Demand Charges and Ratchets

Mr. Chernick would like Manitoba Hydro to reduce or eliminate demand charges and demand ratchets for General Service customers (pages 27 through 31). Mr. Chernick is, in theory, correct that demand charges based on the individual customer peak do not necessarily or always provide the best price signal. Restricting the application of demand charges to peak periods, or replacing them with TOU rates that apply high energy charges to peak periods is a more direct way of signaling the cost of those loads.

Such a rate design requires the capability to meter and bill TOU rates. Absent that capability, the only price signal available to a utility to recognize capacity constraints is a demand charge applied to the customer's own peak demand. Mr. Chernick is correct that such a demand charge may not necessarily allow a customer to distinguish periods when demand reduction is most beneficial. However, it does signal the desirability of reducing peak loads. In Manitoba most customer peak loads, in the General Service Small and Medium rate classes, and for many General Service Large customers as well, occur during the peak winter hours as a matter intrinsic to the customers' operations. Class coincident factor (class load at system peak divided by class load at class peak) is in the order of 90% for both General Service Medium and Large classes. The coincidence factor for all General Service Medium and Large customers individually (class contribution to system peak divided by sum of individual customer peaks) is in excess of 80%. Consequently demand charges applied to individual customer peaks do have an impact on usage at peak hours.

In Manitoba, demand charges are expressed in kV.A and this provides another important incentive: to customers; to improve their power factor. This is particularly important on the numerous long rural feeders serving customers throughout the province.

The demand ratchet, currently set at 70% of maximum winter demand (December, January, and February) acts to reinforce the signal to reduce customer peak load, most of which occurs during the most strained period on the province's Distribution system. Manitoba Hydro has worked extensively with General Service customers to assist them in reducing their demand, and much of customer willingness to work with Manitoba Hydro on demand reductions stems from the price signal available through the combination of the demand charge and winter ratchet.

As Manitoba Hydro noted in its response to PUB/MH I-14(b), other price signals could replace the winter ratchet, notably seasonal and TOU rate designs which provide higher prices for both demand and energy during the peak seasons (June-August and December-February) and the peak hours (weekdays from 7:00 am through 11:00 pm.) However, the winter ratchet remains an important signal until such provisions can be designed and implemented.

Most Canadian utilities have ratchet provisions comparable to Manitoba Hydro's and Manitoba Hydro's provision is within the range of those required by other utilities. For example, ATCO Electric sets an annual ratchet at 85% of the highest demand in the past 12 months and 100% of contract demand. New Brunswick Power's demand ratchet is set at 90% of average monthly demand from the past year, 90% of previous winter demand or 90% of contract, whichever is highest.

Mr. Chernick's evidence appears to be that the ratchet is useful only for utility revenue stability (response to MH/RCM/TREE-15). The impact of Manitoba Hydro's winter ratchet on revenue stability is more a testament to the effectiveness of the ratchet in controlling customer demands.

Ratchet revenue accounts for less than 1% of Manitoba Hydro's revenue from customers whose billing demand is subject to the ratchet provisions.

Having said this, it is also true that a lower demand charge with no ratchet, coupled with a TOU energy rate with a strong winter peak period signal may be even more effective in reducing demand during peak periods. But implementation of such a rate will require resolution of a number of issues, most particularly, the installation of appropriate metering and billing systems for the vast majority of Manitoba Hydro's customers who are currently billed for demand. More than 94% of demand billed customers do not currently have TOU metering capability. It may also require investigation of the potential impacts of such a rate design on commercial and institutional heating loads, particularly outside of areas serviced by natural gas.

<u>Specific Recommendations for April 1, 2008, General Service Rates</u>

Mr. Chernick's specific recommendations for April 1, 2008, are set forth in his evidence from page 25, line 6 through page 31, line 19. These recommendations are either not feasible or not appropriate.

First, Mr. Chernick is recommending something which is impossible, an inverted rate for a service which is un-metered. Flat-rate water heating is exactly as described, a flat monthly charge for energy to a water heater, which is un-metered. The charges vary depending on the watt-size of the water heater and they are based on expected usage and the tail block rate for energy for General Service Small customers. Some of these water heaters receive discounts because they were once subject to remote interruption. The discounts are being phased out, but because the phase-out is not complete, the average revenue for all these services is less than the General Service Small tail block rate. This rate has not been available for new services for many years; consequently, the number of customers served under this rate schedule is in gradual decline.

Second, Mr. Chernick's recommendations with respect to the main General Service Small rate would have unacceptable individual customer impacts and would potentially cause unacceptable increases to peak winter loads on at least some parts of the Distribution system. Mr. Chernick's

PUB/MH I-146

Reference: Quebec Hydro Nov. 2011 Report (P. 43 and P. 49)

d) Please indicate MH intentions with respect to further rate increases being applied only to energy.

ANSWER:

Beginning with its 2004 General Rate Application, Manitoba Hydro has requested rates for all Demand Billed classes (General Service Small Demand, General Service Medium and General Service Large) which applied all of any requested rate increase to the Energy Charges and maintained the Demand Charges at the levels established prior to the 2004 rate change. This approach to General Service rate design was driven by two factors:

1) The PUB had directed Manitoba Hydro to review its balance between demand and energy charges in Order 7/03. That Order, dated February 3, 2003, directed Manitoba Hydro to file with the Board "*a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge.*" In making this directive the PUB expressed an opinion that some of Manitoba Hydro's Demand Charges were in the mid-to-high range as compared to other Canadian jurisdictions, while the utility's Energy Charges were amongst the lowest in Canada.

2) Trends in a number of jurisdictions were such that recovery of supply (ie. Generation) cost was transitioning from both demand and energy charges to recovery through energy charges only, sometimes differentiated by time of use period.

As a result of these factors, Manitoba Hydro believed it was appropriate to emphasize the energy charge in its rate increase proposals, and this has been accepted by the PUB in subsequent GRA Orders. Acceptance of this approach was provided in Order 101/04, pp. 28, 29; 143/04, p. 98; 116/08, pp. 308-09 and, especially, p. 288 where the Order stated:

MH's rate structure has for many years been over-collecting on demand charges and under-collecting on energy charges relative to COSS allocations. In response to Board direction, MH has, since 2003, been assigning rate increases entirely to the energy portion of rates.

The PUB has also supported Manitoba Hydro's comparison of demand and energy revenues to embedded cost as at least one benchmark to track the progress of Manitoba Hydro's rebalancing (Order 116/08, pages 288-289). Moreover, implicit support has also been provided in that Manitoba Hydro's rate structure proposals have always been approved by the PUB since 2004, until the last interim approval in Order 117/12.

A review of current (interim) rates and costs indicates that, while rebalancing has occurred throughout the 2004-2012 period, rates to some of the affected General Service classes are still not fully balanced against the embedded cost benchmark. Manitoba Hydro acknowledges that factors other than embedded cost should also be considered in the allocation of revenue recovery between demand and energy components of the rate structure. These could include: marginal cost, price-responsiveness, time of use considerations and customer characteristics. Most of these factors also favour continuing emphasis on energy charges. Manitoba Hydro intends to continue to emphasize energy charges whenever rate increases are being proposed for General Service classes.

PUB/MH I-147

Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

a) Please discuss and quantify the costs (both fixed and variable) that are theoretically to be recovered from the electric BMC.

ANSWER:

A response to this same question was provided in the 2010/11 & 2011/12 GRA (PUB/MH 1-133 (a)), which has been reproduced below.

PUB/MH I-133

ANSWER:

Currently, the electric BMC for residential customers is $6.85, which recovers approximately 34% of the fixed customer related costs as determined in PCOSS10. If all fixed customer related costs were recovered through the BMC, Manitoba Hydro would need to increase its BMC to approximately $20 per customer per month (as per Appendix 11.1, page 16 of the Application). From a theoretical perspective a basic monthly charge is put in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. The costs recoverable through the BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

It is arguable that customer hook-up and usage is much less influenced by the level of the Basic Monthly Charge than the level of the Demand or Energy charges. Consequently, in a situation such as Manitoba Hydro's in which embedded costs are significantly lower than marginal costs, it is not unreasonable for fixed charges to under-recover relative to fixed costs, to assist in maintaining flexibility to move the more price elastic part of the rate structure, the energy charge, closer to marginal cost. A lower fixed charge and therefore a higher variable rate also assists in allowing the customer greater control over the level of their bill. Additionally, basic monthly charges are typically not well understood or accepted by customers. It is therefore not uncommon for utilities to set the level of the charge below the fully embedded customer costs, a trade off between establishing strictly cost based rates and the practical realities of providing customers with service.

PUB/MH I-147

Preamble: Comparison to Other Jurisdictions

c) Please indicate whether MH intends to increase or decrease the BMC.

ANSWER:

Manitoba Hydro currently has no plans to change the BMC for electric customers. However as noted in response to PUB/MH I-148, the BMC for the General Service Small (Demand) class will have to change to fully consolidate this class with the General Service Medium class.

PUB/MH I-148

Reference: Appendix 10 .2 - Class Consolidation

Please provide an update on the progress toward a common rate structure for GSS (D) and GSM classes.

ANSWER:

Currently the only difference between the GSS (D) and GSM rates is the monthly Basic Charge. Manitoba Hydro has, over the last several rate increases, proposed increases to the monthly Basic Charge for the GSS class in order for this class to eliminate the difference.

The rates Manitoba Hydro was initially considering for April 1, 2013 would have resulted in the two classes (GSS and GSM) being fully consolidated. However based on the PUB's instructions provided to Manitoba Hydro in the preparation of rate schedules for approval for September 1, 2012 the consolidation of these two classes will probably be delayed by at least two rate changes.

GAC/MH I-7

Subject: Proposed Rate Structure
Reference: Proof of Revenue, Appendices 10.1 and 10.8

d) Please provide the basis for the current and proposed "Misc. Rev & Adjs."

ANSWER:

Miscellaneous Revenues and Adjustments pertain to revenues derived from miscellaneous charges. These can be in the form of late payment charges (referred to as Customer Accounting Adjustments), specific read fees, disconnect /reconnect fees, year-end accrual adjustment, etc. Late payment charges however account for the majority of the revenue in this category.

Since Miscellaneous Revenues and Adjustments vary from year-to-year, Manitoba Hydro forecasts this sector based solely on average historical data and proposed rate increases.

GAC/MH II-38

Subject: **Rate Design—Proposed TOU Rate for the Large GS Class**
Reference: **MH response to GAC/MH I-28**

Please provide a complete copy of Manitoba Hydro's Supply Agreement with large customers. If that agreement varies among customers, please provide the variations.

ANSWER:

The attached Power Supply Agreement is presented to all General Service Large customers seeking electric service from Manitoba Hydro. These terms and conditions have been in place since March, 2011. Manitoba Hydro cannot confirm that all customers in this class have executed Power Supply Agreements which are identical to the current version. The form of agreement has been in use for many years and changes have been made to respond to customer/industry demands which changes have not been formally tracked. For information regarding the March, 2011 change please see MIPUG/MH II-22(g).

THIS AGREEMENT made this ____________ day of ____________________, __________.
BETWEEN:

THE MANITOBA HYDRO-ELECTRIC BOARD
(hereinafter referred to as
"Manitoba Hydro"),

OF THE FIRST PART,

- and -

____
(hereinafter referred to as
"the Customer"),

OF THE SECOND PART,

WHEREAS the Customer has applied to Manitoba Hydro for a supply of up to but not more than _____________ kilovolt-amperes (kVA) of power and energy to be used for the operation of a ___________________________ at or near _____________________________, Manitoba (hereinafter referred to as "the plant");

AND WHEREAS Manitoba Hydro has agreed to supply power and energy for the purpose aforesaid on the terms and conditions hereinafter set forth;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and of the Agreements herein contained, the parties hereto agree as follows:

1. Except where the context otherwise requires, the following expressions when used in this Agreement shall have the following meanings: DEFINITIONS

(a) billing year: A period of 12 monthly billing periods commencing with the 1st day of December and ending the 30th day of November of the following year.

(b) month: A billing period of not more than 33 or less than 27 consecutive days between meter readings.

(c) day: A period of 24 consecutive hours commencing at 00:00 hours.

(d) power: The rate of transferring or transforming electric energy, measured or expressed in kVA.

(e) energy: Power integrated with time and measured or expressed in kilowatt-hours (kWh).

(f) demand: The maximum use of power within a specified period, as measured in kVA by means of a 15 minute integrating demand meter.

(g) load: The term used to measure electric power that may be real power or apparent power. The real power is expressed in kilowatts (kW) while the apparent power is expressed in kilovolt amperes (kVA).

AGREEMENT TO SUPPLY

2. From and after ___________________ (hereinafter called the "commencement date"), Manitoba Hydro shall make available to the Customer up to but not more than _____________ kVA of power (hereinafter called the "contracted power") together with the energy supplied with the contracted power for and in connection with the operation of the plant.

INCREASE IN CONTRACTED AMOUNT OF POWER

3. The Customer may by notice to Manitoba Hydro request an increase in the amount of Contracted Power together with the energy supplied with such excess power, at any time, and Manitoba Hydro will use its best endeavours to supply the increased amount of power and energy requested by the date it is required by the Customer, on terms and conditions applicable to Customers in the rate classification in which the Customer will be following such increase.

DECREASE IN CONTRACTED AMOUNT OF POWER

4. (a) The Customer may at any time after a date which is _____ billing year(s) calculated from the 30th day of November next following the commencement date, by notice to Manitoba Hydro, decrease the amount of contracted power. The effective date of the decrease shall be the 1st day of December of the billing year next following the date of the notice, provided that notice is given to Manitoba Hydro at least 60 days prior to the start of the billing year, otherwise the effective date shall be the 1st day of December of the second billing year following the date of the notice.

(b) Manitoba Hydro shall have the right to decrease the amount of contracted power to reflect the customer's recorded demand at any time after a date which is ___________ billing year(s) calculated from the 30th day of November next following the commencement date. Manitoba Hydro shall provide notice to the Customer prior to decreasing the amount of contracted power. The effective date of the decrease shall be the 1st day of December of the billing year next following the date of the notice, provided that notice is given to the Customer at least 60 days prior to the start of the billing year, otherwise the effective date shall be the 1st day of December of the second billing year following the date of the notice.

5. Beginning with the commencement date and thereafter during the term of this Agreement and any continuation thereof, the Customer shall pay for all power and energy made available or supplied by Manitoba Hydro pursuant to this Agreement at the rates and charges set forth in Schedule 'A' which is attached hereto and forms part hereof.

AGREEMENT TO PAY

6. The Customer shall supply, operate and maintain at the Customer's expense during the term of this Agreement a _______________ volt (V) disconnecting facility (hereinafter called the "switch") at or near the Customer's plant.

SWITCH

7. (a) The point of delivery for the power and energy made available or supplied to the Customer by Manitoba Hydro pursuant to this Agreement shall be the ____ as shown on Manitoba Hydro Drawing No. _______________ which is attached hereto as Schedule 'B' and forms part hereof.

POINT OF DELIVERY

(b) If Manitoba Hydro supplies and installs primary voltage wires and facilities on the Customer's property to accommodate the Customer's preferred location for the point of delivery, all costs associated with the repair or replacement of those wires and facilities between the point of delivery and the Customer's property line shall be paid by the Customer.

8. All power and energy supplied to the Customer by Manitoba Hydro shall be measured at or near the point of delivery using metering equipment of commercial accuracy approved by Measurement Canada. Such metering equipment shall be supplied and maintained by Manitoba Hydro. METER READINGS

9. The Customer shall provide, and maintain without charge, convenient, accessible, and safe space at or near the point of delivery for Manitoba Hydro's metering equipment, which shall be in the care and at the risk of the Customer and if lost, destroyed, or damaged (other than by ordinary wear and tear), the Customer shall pay Manitoba Hydro on demand an amount equal to the cost of repairing or replacing it, as determined by Manitoba Hydro. METER LOCATION

10. Authorized employees of Manitoba Hydro shall at all reasonable times have free and uninterrupted access to the Customer's premises for the purposes of reading Manitoba Hydro's meters. ACCESS TO METERS

11. (a) Manitoba Hydro may test, calibrate, remove and replace its metering equipment at any time. METER TESTING

(b) If Manitoba Hydro receives notice from the Customer to test any metering equipment used for the purposes of this Agreement, Manitoba Hydro shall perform testing of such metering equipment at the Customer's location. If the Customer is not satisfied with the results, the Customer may request testing of the metering equipment by Measurement Canada, upon payment of a fee to Manitoba Hydro. The Customer shall be notified in advance by Measurement Canada of the time and place of all tests and shall be entitled to be present or represented at such tests. If the tests prove or indicate the metering equipment is within commercial accuracy, as required by *The Electricity and Gas Inspection Act*, R.S.C. 1985, c. E-4, as revised from time to time, the fee will be forfeited by the Customer. If such tests prove or indicate that the metering equipment is not within commercial accuracy, then Manitoba Hydro shall refund the fee paid by the Customer and the Customer's account shall be adjusted in accordance with Measurement Canada's findings.

12. If Manitoba Hydro's metering equipment fails to register, or fails to register correctly, or if for any reason the meter readings are unobtainable, the amount of power and energy supplied to the Customer will be estimated by Manitoba Hydro from the best information available based on the Customer's operations during the period in question, and such estimate shall have the same force and effect as a metering reading.

FAULTY METERING EQUIPMENT

13. All power and energy supplied to the Customer at the point of delivery shall be in the form of three phase, 60 Hertz alternating current, at a nominal ________________ V, and shall be maintained in accordance with Power Quality Specification: PQS2000, rev. 02 attached to and forming part of this Agreement.

CHARACTERISTICS OF POWER AND ENERGY

14. (a) The Customer shall operate its electrical equipment in a manner that will not cause Manitoba Hydro's power supply to vary in voltage, frequency or wave form in accordance with Power Quality Specification: PQS2000, rev. 02, attached to and forming part of this Agreement.

CONTROL OF EQUIPMENT

(b) Where Manitoba Hydro becomes aware that the Customer's electrical equipment is causing interference to other Manitoba Hydro Customers, Manitoba Hydro shall advise the Customer of same and the Customer, at its own expense, shall take all necessary action to correct the problem to Manitoba Hydro's satisfaction.

(c) When the interference is caused by more than one Customer, Manitoba Hydro will determine the cause of the interference and will determine the responsibility of each of the Customers involved. The Customers involved maybe responsible for the costs and mitigation.

(d) Manitoba Hydro, in its discretion, will assist the Customer in making necessary corrections to the Customer's electrical equipment to correct electrical interference problems upon the Customer's request and following receipt of the Customer's payment for all materials and services to be provided by Manitoba Hydro in making the corrections. Such assistance will normally be by way of Manitoba Hydro providing:

i) upgraded transformer capacity; or

ii) a dedicated transformer; or

iii) an additional point of delivery.

15. Manitoba Hydro shall have the right to interrupt the supply of power and energy to the Customer at any time for the purpose of safeguarding life and property, and/or for the purpose of inspecting, maintaining, repairing, replacing, improving and adding to Manitoba Hydro's facilities or equipment. All such interruptions shall be of the minimum durations practicable and, whenever possible, shall be made after reasonable notice has been given to the Customer and at a time least inconvenient to the Customer. INTERRUPTIONS

16. Manitoba Hydro shall not be liable to the Customer or to any other person, whether in contract, tort, equity, or otherwise, for any losses, costs, damages or expenses, directly or indirectly resulting from any fluctuation, interruption, reduction or failure in the supply of power to the Customer. LIABILITY

17. If, for any reason whatsoever, Manitoba Hydro is unable to make power and energy available to the Customer for a period in excess of one day during any month, then the billing demand for that month shall be adjusted by multiplying the monthly billing demand determined in accordance with Schedule 'A' by the ratio which the actual number of days when power and energy were made available in that month bears to the total number of days in that month. Fractions of less than a half-day shall be disregarded and a half-day or more shall be taken as a full day. The bill for the month in which an interruption occurs shall be the total of: ADJUSTMENT FOR INTERRUPTIONS

(a) the adjusted monthly billing demand multiplied by the demand charge, and

(b) the energy charge.

18. If by reason of fire, flood, lightning, windstorm, earthquake, explosion, riot, malicious mischief, war, or the lawful orders of civil or military authorities, but no other event or occurrence, (hereinafter called a "major calamity"), the Customer is unable to operate the plant for a period of more than one day, then the monthly billing demand for the period when the plant did not operate up to but not exceeding 60 days in any billing year shall be adjusted by multiplying the monthly billing demand, determined in accordance with Schedule 'A', by the ratio which ADJUSTMENT FOR MAJOR CALAMITY

the actual number of days when power and energy were provided in that month bears to the total number of days in that month. Fractions of less than a half-day shall be disregarded and a half-day or more shall be taken as a full day. The bill for the month in which a major calamity occurs shall be the total of:

(a) the adjusted monthly billing demand multiplied by the demand charge, and

(b) the energy charge;

provided, however, that the monthly bill for the period during which the plant did not operate shall not normally be less than an amount determined by multiplying __________ kVA by the demand charge. If by reason of a major calamity, the Customer is unable to operate the plant for a period of more than 60 days in any billing year, the Customer shall pay Manitoba Hydro commencing on the 61st day after the major calamity, a monthly amount calculated in accordance with Schedule 'A'.

19. Bills for power and energy submitted by Manitoba Hydro to the Customer shall be due and payable by 12:00 Noon Winnipeg time 14 days from the date thereon, at such location as Manitoba Hydro may from time to time designate by notice to the Customer. TERMS OF PAYMENT

Manitoba Hydro may, in its sole discretion, assign the account to weekly billing if payment or payment arrangements have not been made by the due date. Weekly billing will thereafter continue at Manitoba Hydro's discretion.

20. Overdue bills shall bear interest until paid at such rate as may from time to time be established by Manitoba Hydro as applicable to all its Customers. If any bill remains unpaid after the due date thereof, Manitoba Hydro may, without prejudice to any other remedy it may have, and after giving the Customer not less than 20 days notice, discontinue the supply of power and energy until such time as the said bill, as well as all further charges accruing up to and including the date on which the supply of power and energy were discontinued, together with interest computed as aforesaid, have been paid in full. No such discontinuation of the supply of power and energy by Manitoba Hydro shall relieve the Customer of its obligation to pay for power and energy under the terms of this Agreement. LATE PAYMENT PENALTY

21. If during the term of this Agreement, Manitoba Hydro makes a general revision of its rates for power and energy affecting Customers in the same rate classification as the Customer, the rates and charges for power and energy set forth in Schedule 'A' attached hereto shall be deemed to be revised as of the effective date of the rate revision to conform with the revised rates. RATE REVISION

22. All bills for power and energy and all notices which Manitoba Hydro may be required to give the Customer pursuant to this Agreement shall be in writing sent by mail or written telecommunication addressed to ____________________________ ____. The Customer may from time to time change the address to which such bills and notices are to be sent by giving notice to Manitoba Hydro. NOTICE TO CUSTOMER

23. All notices to Manitoba Hydro shall be in writing sent by mail or written telecommunication addressed to the Manager - __________________, Manitoba Hydro at __________________ ____. NOTICE TO MANITOBA HYDRO

24. This Agreement is subject to *The Manitoba Hydro Act*, R.S.M. 1987, c. H190, as amended from time to time, and Regulations made thereunder. THE MANITOBA HYDRO ACT

25. This Agreement shall be effective on the date hereof and shall continue in full force and effect for a period of __________ billing year(s), calculated from the 30th day of November next following the commencement date, and if not then terminated by not less than 60 days written notice by one party to the other party, shall continue in force from month to month until so terminated. TERM OF AGREEMENT

26. On the commencement date, this Agreement shall supersede any and all previous Agreements between Manitoba Hydro and the Customer for the supply of power and energy to the plant. TERMINATION OF PRIOR AGREEMENT

27. Except as provided in paragraph 21, every amendment or supplement to this Agreement shall be in writing, dated and executed by the proper officers on behalf of each of the parties. AMENDMENTS

28. This Agreement shall enure to the benefit of and be binding upon the parties hereto, their successors and assigns. ENUREMENT

IN WITNESS WHEREOF Manitoba Hydro and the Customer have caused this Agreement to be executed on the date first above written.

APPROVED AS TO	
	CONTENT Manager ___________ ___________
	FORM Manager Rates & Policies

THE MANITOBA HYDRO-ELECTRIC BOARD
Per:

____
Authorized Signing Officer

____
Per:

Witness	Authorized Signing Officer	Print Name
Witness	Authorized Signing Officer	Print Name

SCHEDULE 'A'

This is Schedule 'A' referred to in an Agreement between The Manitoba Hydro-Electric Board and ____ made on the __________ day of ________________, __________.

The following rates and charges shall apply to all power and energy made available or supplied to the Customer pursuant to this Agreement.

GENERAL SERVICE - LARGE - __________ V

Energy Charge - __________ per kWh

Demand Charge - __________ per kVA of the monthly billing demand

Monthly Billing Demand

The greatest of the following (expressed in kVA):

(a) measured demand

OR

(b) __________ kVA (25% of contract demand)

OR

(c) 25% of the highest measured demand in the previous 12 months

Monthly Bill

The monthly bill shall be the total of the amounts payable for the demand charge and the energy charge.

Rate effective on and after: September 1, 2012.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

e) For each customer in part (b), please indicate whether the customer initially provided capital contributions to Hydro to pay for the capital costs of installation of transmission and distribution infrastructure. If for any of the customers the answer is yes, why would the customer now be required to "release" this capacity?

ANSWER:

Large General Service customers served at 30 kV and above are required to provide capital contributions for dedicated portions of infrastructure required for provision of supply to their facilities, including taps, line extensions, etc. Costs incurred for dedicated facilities provide no additional benefit to Manitoba Hydro beyond that obtained from providing service to a specific customer (i.e. revenue for energy consumed) and are therefore provided on a cost recovery basis.

System improvement costs, which are incurred to enhance the capacity and operation of the bulk system, can be segregated into two categories. Those costs incurred to provide for general capacity improvements and operation of the transmission and distribution system are allocated to the general rate base in accordance with the cost of service study. Load growth from large customers is included in planning for regional transmission and distribution improvements. The second category includes costs incurred to provide capacity and support for a distinguishable new or expanding load brought onto the system by a specific customer, generally require a customer contribution in proportion to the share of their contribution to the requirement for the improvements. Such distinguishable load growth may force Manitoba Hydro to accelerate planned system improvements, or enhance portions of the system that would otherwise not be required.

Each customer listed in the response to part b) would have provided contributions for dedicated costs incurred to serve their facility. The vast majority of these contributions were related to dedicated infrastructure that provided no benefit to Manitoba Hydro in respect to general capacity or operational improvements. Systems improvement costs were incurred in some instances, primarily for conductor upgrades/additions and switching improvements. In those instances, the costs related to the customers' portion of the upgrades required a contribution.

Regional constraints at the transmission and distribution station level often occur further into the system than the improvements towards which a customer may contribute when adding load. The scope of a customer's contribution is determined at the time that service is requested, and may therefore not extend to the full reach of the regional system serving their localized area. Those components of the system, which were funded by the general rate base, may have provided adequate capacity at the time of the service request. As time advances, those components of the system may become constrained due to general load growth, requiring Manitoba Hydro to incur costs for station upgrades and other system improvements. Unused capacity contracted by customers contributes to those constraints and accelerates the timeline for expenditures needed increase capacity and support operation of the transmission and distribution system.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

f) Please provide Hydro's definition for "sustained periods of time" as per paragraph 1 of GAC/MH-1-25(b). Is this intended to refer to periods of months, years, etc.?

ANSWER:

For the purposes of historical reference used in the response to GAC-MH I-25(b), "sustained periods of time" was intended to refer to periods of years.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

g) Please indicate what is meant by "Contractually, customers have historically not been required to release unused capacity in order for Manitoba Hydro to serve other load…". Is there a proposed change in the contractual obligations on customers to release unused capacity at this time, or only a change to impose demand charges on the customers for this unused capacity? If there is a also a proposed change in the contractual terms between Hydro and new or existing customers, please provide copies of the existing terms (if any) governing unused capacity, the proposed new terms governing unused capacity, the impact if any on existing customers (or whether such change would only apply to new customers) and the effective date when Hydro will begin implementing such new provisions in customer contracts.

ANSWER:

Earlier legacy supply agreements do not have specific clauses enabling Manitoba Hydro to recover unused capacity after a specified period of time. More recent contracts do have such a clause included in the wording of the supply contract. The specific clause from the current version of the supply agreement in included as a reference below:

Clause 4 (b) of the current Supply Agreement states:

> *Manitoba Hydro shall have the right to decrease the amount of contracted power to reflect the customer's recorded demand at any time after a date which is ____ billing year(s) calculated from the 30th day of November next following the commencement date. Manitoba Hydro shall provide notice to the Customer prior to decreasing the amount of contracted power. The effective date of the decrease shall be the 1st day of December of the billing year next following the date of the notice, provided that the notice is given to the Customer at least 60 days prior to the start of the billing year, otherwise the effective date shall be the 1st day of December of the second billing year following the date of the notice.*

No customer subject to the current version of the supply agreement will be impacted based on current or projected operating demand levels. These terms only apply to customers entering into the new Supply Agreement, and therefore do not impact customers under older legacy agreements.

Manitoba Hydro has implemented this contract language in its agreements effective March 15, 2011.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

h) For an industrial customer who does not use their contracted capacity for a sustained period of time, and consequently releases such capacity to Hydro for other customer use, would that industrial customer be required to make new capital contributions and/or risk failing to receive an allocation of future capacity in the event the originally contracted demand is required in future?

Under the April 1, 2013 proposed Time of Use rates, if a customer has a contract for 100 MV.A, an on-peak demand of 40 MV.A and an off-peak demand of 70 MV.A, would that customer still face a 50 MV.A ratchet demand charge (i.e., 50% of contract demand)? How would this added demand charge be in any way related to “unused capacity”?

ANSWER:

Customers that release capacity and subsequently request additional capacity may be required to make capital contributions for additional capacity if Manitoba Hydro incurs costs that are subject to customer contribution for providing the requested capacity increase.

Under the proposed time-of-use application, customers would be subject to a minimum demand charge based on the greatest of the measured on-peak demand, 50 percent of contract demand, or 50 percent of the highest recorded on-peak demand in the past 12 months.

As Manitoba Hydro’s system load is greatest in the on-peak period, unused capacity in the on-peak period may be useful to Manitoba Hydro for providing service to other domestic customers served by the same regional portion of the transmission system. Serving that load may otherwise require expansion of the Manitoba Hydro system resulting in additional costs to the Corporation and its ratepayers.

It is important to recognize that under the current rate structure, the described customer profile would result in a peak demand bill of 70 MVA. The time-of-use proposal provides the customer with a lower peak demand bill of 50 MVA under that same scenario based on a minimum demand bill of 50 percent of contract demand.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

f) Service Extension Policy

Please file MH's current service extension policy and a summary of its actual usage in the last 5 years.

ANSWER:

The current service extension policy is shown below. Manitoba Hydro tracks these projects individually and as these are larger customers only a few extensions are undertaken each year. Several projects are also initiated but do not proceed.

Maximum Allowance - Customer-Owned Transformation

Effective 2005 06 23 and until further notice, no Corporate allowance will be made in facilities required to serve new loads exceeding 30 kV or loads in excess of 5 MW without approval of Manitoba Hydro's Executive Committee.

The maximum allowance for primary voltage service, other than those exceeding 30 kV or loads exceeding 5 MW, where the customer owns the transformation, is three times the estimated annual revenue, applied to specific Corporate facilities, as follows:

a) Not exceeding 30 kV – applicable to facilities which are not on private property;

b) Exceeding 30 kV – applicable to the cost of upgrading the Corporation's existing common integrated system on the supply side of the point where facilities tap into the system.

CAC/MH I-86

Subject: **Proposed Rates and Customer Impacts**
Reference: **Tab 10, Appendix 10.6**

a) **To what extent do the peak, shoulder and off-peak period definitions used for the SEP align with the peak and off-peak hours as defined for the potential time-of-use pricing? If there is no clear alignment, please explain why Manitoba Hydro is not proposing to have the hours correspond as it is for the Curtailable Rate program.**

ANSWER:

The SEP hours definition does not align with those being proposed for the Curtailable Rate Program (CRP) and potential Time-of-Use (TOU) rates.

Although it would be possible to change the SEP hour definition to align, Manitoba Hydro is leaving the definition unchanged for the following reasons:

- Since the inception of the SEP in 2000, the program has always operated under three pricing periods (peak, shoulder and off-peak) whereas the new TOU program is proposed to operate under two pricing periods. In 2000 Manitoba Hydro joined the MISO market where prices are determined based on eastern load patterns. SEP hours were determined at a time when Manitoba Hydro was selling mainly into MAPP where prices were determined by Minnesota load patterns.
- Changing the defined hours of the SEP pricing periods would have no benefit to Manitoba Hydro or SEP customers. In fact administrative costs would have to be incurred to make changes to align the SEP hours to the TOU hours.
- SEP customers may be adverse to the change in hours as they have been accustomed to the three period pricing and have adopted their operations to these pricing periods.

GAC/MH I-22

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 2:

a) Please explain whether Hydro believes that time-of-use rates "Mitigate the Impact of Low Domestic Industrial Rates," to wit, that "Low energy rates attract energy-intensive load to Manitoba," reducing exports, requiring new resources, and increasing average costs and rates. If so, please explain how Hydro believes that time-of-use rates mitigate this problem.

ANSWER:

Time-of-Use rates would provide a clearer price signal to prospective energy-intensive loads regarding the value that firm export sales of on-peak energy provides to Manitoba Hydro and its domestic ratepayers. It is anticipated a strong on-peak time-of-use price signal will support the inclusion of load shifting and off-peak operation as key considerations for both existing and prospective energy intensive customers. Integration of these operational considerations into the planning process for new facilities will support enhanced firm export opportunities for Manitoba Hydro and reduced operating costs for energy-intensive customers, benefiting both parties.

GAC/MH I-22

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 2:

b) Would the proposed time-of-use rates charge new energy-intensive base-load industrial operations as much as Hydro could earn on firm export contracts?

ANSWER:

Time-of-Use rates are intended to provide an on-peak price signal that is reasonably correlated to the rates obtained from current firm export contracts in the on-peak period. The rate structure proposed provides for greater flexibility in adjusting future Time-of-Use rates to continue sending a price signal that is comparable to anticipated firm export contracts that may be negotiated going forward.

GAC/MH I-22

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 2:

c) Please explain how time-of-use rates would "Promote conservation" in the off-peak period.

ANSWER:

Manitoba Hydro anticipates that higher on-peak Time-of-Use rates would encourage conservation in critical on-peak periods when capacity constraints for both demand and energy are most pronounced and costly to address. In general, it is anticipated that measures implemented to support improved energy efficiency and conservation in the on-peak period would have residual benefits in the off-peak period as well.

GAC/MH I-23

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 4:

a. **Please describe in detail the "Problem with two-tier rate design for industrial loads."**

b. **Please describe in detail the "Challenge when applied to new and/or expanding loads."**

c. **Please explain how time-of-use rates would "Greater incentive for conservation activities" in the off-peak period.**

d. **Please explain how time-of-use rates would "support economics for renewable energy initiatives," including**

- **i.** **Explaining whether this assertion refers to customer decisions to install renewable energy generation behind the meter, Hydro's renewable energy initiatives, or something else.**
- **ii.** **Providing any analysis Hydro has conducted (or reviewed) of the economics of solar, wind, biomass or other renewable energy options under Hydro's standard rate designs and the proposed time-of-use rates.**

e. **Please explain how an energy-intensive customer would shift on-peak load into Manitoba without shifting off-peak load as well.**

ANSWER:

a. The problem with two-tiered rate design for industrial customers is that a separate baseline must be determined for each customer served on this rate. Baseline determination is particularly complicated in an industrial environment where facility loads are significantly influenced by production levels that are driven by global and regional economic conditions, intra-company competition for production allocations, and inter-company competition for market share.

b. Manitoba Hydro’s EIIR contemplated a mechanism that addressed new load growth arising from expansion of existing industrial facilities and load growth from “New-to-Manitoba” industrial facilities. Application of two-tier rates creates an inequity between these two sources of load growth. The application of a baseline with a second higher-priced tier will generally result in any incremental load from an existing customer being charged at a higher rate, while a “New-to-Manitoba” customer will have the majority of their new load charged at the lower baseline rate, despite the fact that both customers contribute incremental load growth. The customer may perceive an inequity as a result of in the relative economic advantages and disadvantages for customers competing within the same sector that are purely related to the application of energy rates.

c. Please see Manitoba Hydro’s response to GAC/MH I-22(c).

d. Higher on-peak rates may encourage industrial customers to implement peak-shaving systems that utilize resources such as renewable biomass, waste streams, and other fuel sources to reduce facility demand and consumption during higher-priced periods. Such applications may include behind-the-meter generation, process and/or space heating with alternative renewable fuels, etc.

Manitoba Hydro has not undertaken an in-depth analysis of the economics of solar, wind, biomass or other renewable energy options relative to the proposed on-peak Time-of-Use rates, other than having subjective discussions with customers on the relative costs of renewable energy sources.

e. Some large energy intensive companies have regionally or globally distributed production facilities that share similar processes and operations. In some instances, excess capacity may be utilized with minimal lead-time or additional costs. Low uniform rates may encourage customers with facilities in Manitoba to shift load to the Province during higher-priced periods in other jurisdictions, creating additional and unexpected demand levels in Manitoba. That load may then be returned to other jurisdictions during lower-priced periods in those locales.

GAC/MH I-24

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 5:

a. **Other than the convenience of using the MISO periods, is there any basis for selecting the 6 AM to 10 PM on-peak period?**

b. **Please provide Hydro's estimate of the hourly export price by hour, historically and forecast, that it used in selecting the on-peak period.**

c. **If Hydro has reviewed the hourly average prices by month or averaged over the year, please provide that analysis.**

d. **Did Hydro consider different peak hours for the summer, when the highest MISO prices for the Manitoba Hydro interface occur in the afternoon, than for the winter, when the highest prices occur in the morning and evening? If so, please explain why Hydro rejected that option.**

e. **Did Hydro consider three price blocks, to reflect the differences among hours during the 16-hour on-peak period? If so, please explain why Hydro rejected that option.**

f. **Did Hydro review export prices during the Saturday 6 AM to 10 PM period, to determine whether those hours (or a subset) should be included in the on-peak period?**

g. **Please provide the analysis from which Hydro determined that March should be a winter month.**

h. **Please provide the analysis from which Hydro determined that July and August do not merit on-peak prices comparable to the designated winter months.**

ANSWER:

a. The MISO on-peak period of 6:00 am to 10:00 pm, Monday – Friday, reflects a time period that is highly relevant to time-of-use valuation of energy for purposes related to the management of extra-provincial market exports and imports. The intention of the time-of-use rate was to provide a price-signal to domestic industrial customers that clearly indicated the relative time-value of energy to Manitoba Hydro.

b. Historical market prices were applied to industrial load shapes and aggregated over the applicable seasonal and on-off peak periods for the purposes of analysis and comparison to prospective time-of-use rates. Manitoba Hydro did not develop estimates or forecasts of hourly export prices for the purposes of this comparison, rather relied upon historical MISO market prices. Please see Manitoba Hydro's response to part c of this response.

c. The average of aggregated MISO market prices for seasonal and on-off peak periods at the Manitoba Hydro delivery point (not including transmission charges) applied to Manitoba industrial load shapes were provided in Slides 7 to 9 of the stakeholder presentation provided on August 15, 2012. Please find a copy of the presentation attached to this response.

d. Manitoba Hydro chose not to apply different on-off peak hours during the summer months for reasons related to simplicity of rate design, ease of rate application and the desire to send a consistent on-off peak price signal that customers can respond to in a consistent and material fashion. It is Manitoba Hydro's view that the on-peak summer period time-of-use rate represents a reasonable price signal for the spring/fall shoulder and summer periods.

Response to parts (e) and (f):

The 6:00 am to 10:00 pm, Monday to Friday on-peak period was chosen based on Manitoba Hydro's desire to provide a price signal to domestic customers that reflected Manitoba Hydro's historic 5 x 16 export contracts, which provide an important indication of on-peak energy valuation to the Corporation.

g. March is generally considered to be a winter month in both the MISO and Manitoba Hydro jurisdictions. Manitoba Hydro designated its winter and non-winter (summer) time-of-use periods based on water flow conditions. During December to March, ice limits Manitoba Hydro's ability to generate hydraulic energy in northern Manitoba.

h. Simplicity is an important objective in the design of the Time-of-Use rate structure, as it allows customers to respond to price signals in a reasonable fashion. Additional time periods and seasonality may make a Time-of-Use rate more representative of a market rate, but this increases the complexity of the price signal being provided to customers. The Time-of-Use rate is not based exclusively on market behavior. It is Manitoba Hydro's view that the on-peak summer period time-of-use rate represents a reasonable price signal for the spring/fall shoulder and summer periods.

Time-of-Use Rates

Stakeholder Conference

August 15, 2012

Rate Design Objectives

- Mitigate the Impact of Low Domestic Industrial Rates
  - Low energy rates attract energy-intensive load to Manitoba
  - On-peak load growth reduces energy available for export
  - Lower domestic rate decreases general utility revenues
- Ability to Secure High-Value Firm Export Contracts
  - Uncertainty regarding potential industrial load growth
  - Large incremental growth in on-peak period has strong influence
  - Lack of a market representative price signal to customers
- Address PUB Directives
  - Board Order 112/09 on Energy Intensive Industrial Rates
  - Evaluation of alternative proposals and rate designs
  - Promote conservation through rate design options

Time-of-Use Rate Design

- Broad-Based Applicability Across Rate Class
  - All load growth contributes to loss of profitable export revenue
- Revenue Neutral across each Rate Class
  - Maintains economic advantage of favorable Manitoba rates
- Provides Equity for all Accounts within Rate Class
  - Expanding loads and New-to-Manitoba loads treated similarly
  - Eliminates discriminatory aspect of formula-based rates
- Time-of-Use Price Signal Related to Market Price
  - Reflects value to Manitoba Hydro in the on-peak period
- Removes Impediments for Load Shifting to Off-Peak
  - Reduces demand charges for peak demand billings
  - Eliminates off-peak demand charge (capped by contract)

Time-of-Use Rate Design

- Eliminates Difficulty of Baseline Determination
  - Problem with two-tier rate design for industrial loads
  - Challenge when applied to new and/or expanding loads
- Communicates Value of Energy in the On-Peak Period
  - Discourages excessive energy consumption in peak periods
  - Greater incentive for conservation activities
  - Supports economics for renewable energy initiatives
  - Provides degree of on-peak export revenue protection
- Addresses Issues of Capacity Constraints in Delivery
  - Minimum billing demands related to contract capacity
- Commonly Applied Rate Structure in Other Jurisdictions
  - Multi-national customers operating across North America
  - Mitigates against on-peak load shifting into Manitoba

Time-of-Use Definition

- Corresponds with MISO Market On/Off Peak Periods
- Relates to Seasonal Periods of Energy Constraint
- Daily On-Peak Period
  - Monday to Friday - 6:00 AM to 10:00 PM
  - Excluding statutory holidays
- Daily Off-Peak Period
  - Monday to Friday - 10:00 PM to 6:00 AM
  - 24 hours – weekends and statutory holidays
- Seasonal Aspect
  - Winter Period (Dec to Mar)
  - Summer Period (Apr to Nov)

Indicative Time-of-Use Rate

	Time-of-Use	Current Structure
General Service Large (> 100 kV)		
Winter On-Peak Energy per kW.h	$0.0519	$.0298
Summer On-Peak Energy per kWh	$0.0419	$.0298
Off-Peak Energy per kWh	$0.0255	$.0298
On-Peak Demand per kVA	$2.70	$5.40
General Service Large (30 – 100 kV)		
Winter On-Peak Energy per kWh	$0.0550	$.0312
Summer On-Peak Energy per kWh	$0.0450	$.0312
Off-Peak Energy per kWh	$0.0285	$.0312
On-Peak Demand per kVA	$3.03	$6.06

MISO On/Off Peak Behaviour

GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (CDN$)

Fiscal	Average ($/kWh)	On-Peak ($/kWh)	Off-Peak ($/kWh)	Ratio (On/Off)
2006/07	$ 0.0541	$ 0.0720	$ 0.0393	1.83
2007/08	$ 0.0490	$ 0.0663	$ 0.0349	1.90
2008/09	$ 0.0409	$ 0.0564	$ 0.0279	2.02
2009/10	$ 0.0256	$ 0.0330	$ 0.0195	1.69
2010/11	$ 0.0257	$ 0.0324	$ 0.0202	1.60
2011/12	$ 0.0220	$ 0.0278	$0.0174	1.60
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0345	$ 0.0454	$ 0.0255	1.78
Demand & Energy	$ 0.0395	$ 0.0560	$ 0.0255	2.19

Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

MISO Seasonal Behaviour

GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (CDN$)

Fiscal	Average ($/kWh)	Winter ($/kWh)	Summer ($/kWh)	Ratio (Win/Sum)
2006/07	$ 0.0541	$ 0.0658	$ 0.0477	1.38
2007/08	$ 0.0490	$ 0.0575	$ 0.0444	1.30
2008/09	$ 0.0409	$ 0.0427	$ 0.0400	1.07
2009/10	$ 0.0256	$ 0.0345	$ 0.0211	1.64
2010/11	$ 0.0257	$ 0.0268	$ 0.0250	1.07
2011/12	$ 0.0220	$ 0.0216	$0.0223	0.97
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0345	$ 0.0375	$ 0.0329	1.14
Demand / Energy	$ 0.0395	$ 0.0420	$ 0.0378	1.11

Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

MISO On-Peak Behaviour

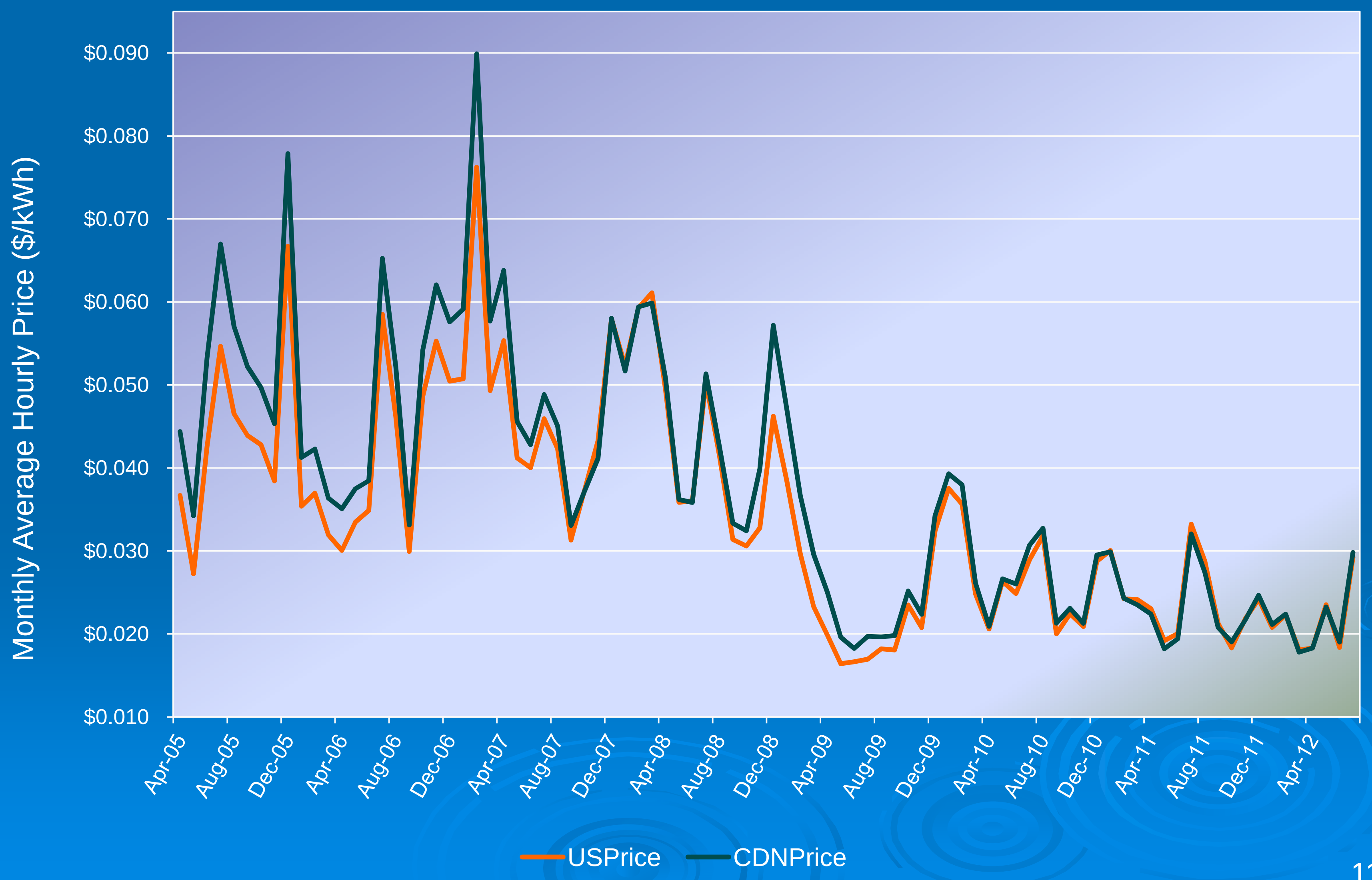
GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (CDN$)

Fiscal	Average ($/kWh)	Winter ($/kWh)	Summer ($/kWh)	Ratio (Win/Sum)
2006/07	$ 0.0720	$ 0.0834	$ 0.0658	1.27
2007/08	$ 0.0663	$ 0.0736	$ 0.0625	1.18
2008/09	$ 0.0564	$ 0.0540	$ 0.0576	0.94
2009/10	$ 0.0330	$ 0.0420	$ 0.0283	1.48
2010/11	$ 0.0324	$ 0.0328	$ 0.0321	1.02
2011/12	$ 0.0278	$ 0.0255	$0.0290	0.88
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0454	$ 0.0519	$ 0.0419	1.24
Demand & Energy	$ 0.0557	$ 0.0625	$ 0.0525	1.19

Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

US-CDN Exchange Rate Impact

Monthly MISO Average Price



MISO On/Off Peak Behaviour

GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (US$)

Fiscal	Average ($/kWh)	On-Peak ($/kWh)	Off-Peak ($/kWh)	Ratio (On/Off)
2006/07	$ 0.0474	$ 0.0632	$ 0.0345	1.83 (1.83)
2007/08	$ 0.0474	$ 0.0642	$ 0.0338	1.90 (1.90)
2008/09	$ 0.0370	$ 0.0513	$ 0.0249	2.06 (2.02)
2009/10	$ 0.0234	$ 0.0301	$ 0.0179	1.68 (1.69)
2010/11	$ 0.0251	$ 0.0317	$ 0.0198	1.60 (1.60)
2011/12	$ 0.0223	$ 0.0281	$0.0176	1.60 (1.60)
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0345	$ 0.0454	$ 0.0255	1.78
Demand & Energy	$ 0.0395	$ 0.0560	$ 0.0255	2.19

Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

MISO Seasonal Behaviour

GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (US$)

Fiscal	Average ($/kWh)	Winter ($/kWh)	Summer ($/kWh)	Ratio (Win/Sum)
2006/07	$ 0.0474	$ 0.0564	$ 0.0425	1.33 (1.38)
2007/08	$ 0.0474	$ 0.0579	$ 0.0418	1.39 (1.30)
2008/09	$ 0.0370	$ 0.0345	$ 0.0382	0.90 (1.07)
2009/10	$ 0.0234	$ 0.0327	$ 0.0187	1.75 (1.64)
2010/11	$ 0.0251	$ 0.0268	$ 0.0242	1.11 (1.07)
2011/12	$ 0.0223	$ 0.0214	$0.0229	0.93 (0.97)
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0345	$ 0.0375	$ 0.0329	1.14
Demand / Energy	$ 0.0395	$ 0.0420	$ 0.0378	1.11

Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

MISO On-Peak Behaviour

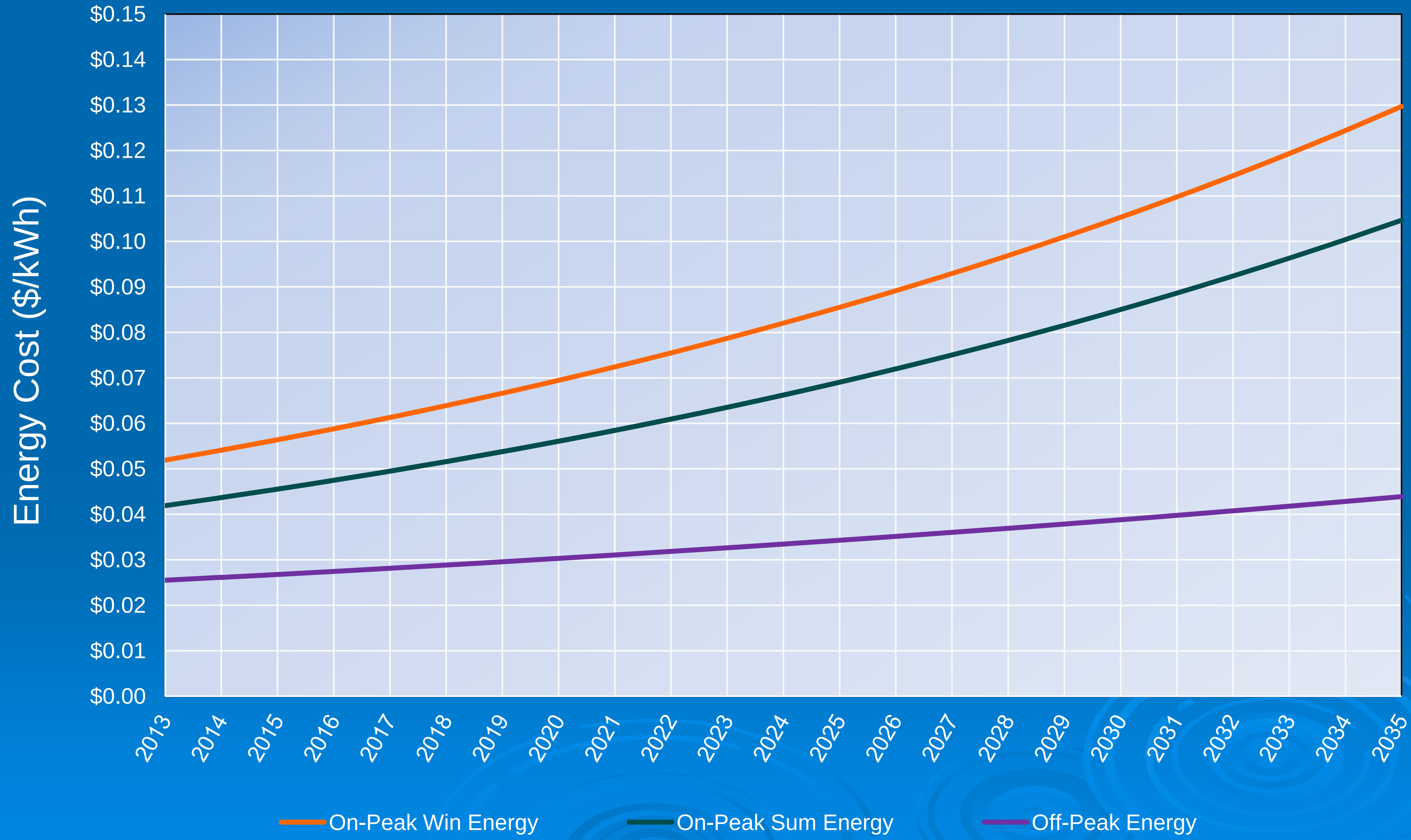
GSL >100 kV Domestic Load Profile applied to Hourly Day-Ahead Market Pricing (US$)

Fiscal	Average ($/kWh)	Winter ($/kWh)	Summer ($/kWh)	Ratio (Win/Sum)
2006/07	$ 0.0632	$ 0.0715	$ 0.0586	1.22 (1.27)
2007/08	$ 0.0642	$ 0.0741	$ 0.0591	1.25 (1.18)
2008/09	$ 0.0513	$ 0.0436	$ 0.0552	0.80 (0.94)
2009/10	$ 0.0301	$ 0.0398	$ 0.0251	1.59 (1.48)
2010/11	$ 0.0317	$ 0.0328	$ 0.0310	1.06 (1.02)
2011/12	$ 0.0281	$ 0.0253	$0.0297	0.85 (0.88)
Proposed Industrial Time-of-Use Rate (CDN$)				
Energy Only	$ 0.0454	$ 0.0519	$ 0.0419	1.24
Demand & Energy	$ 0.0557	$ 0.0625	$ 0.0525	1.19

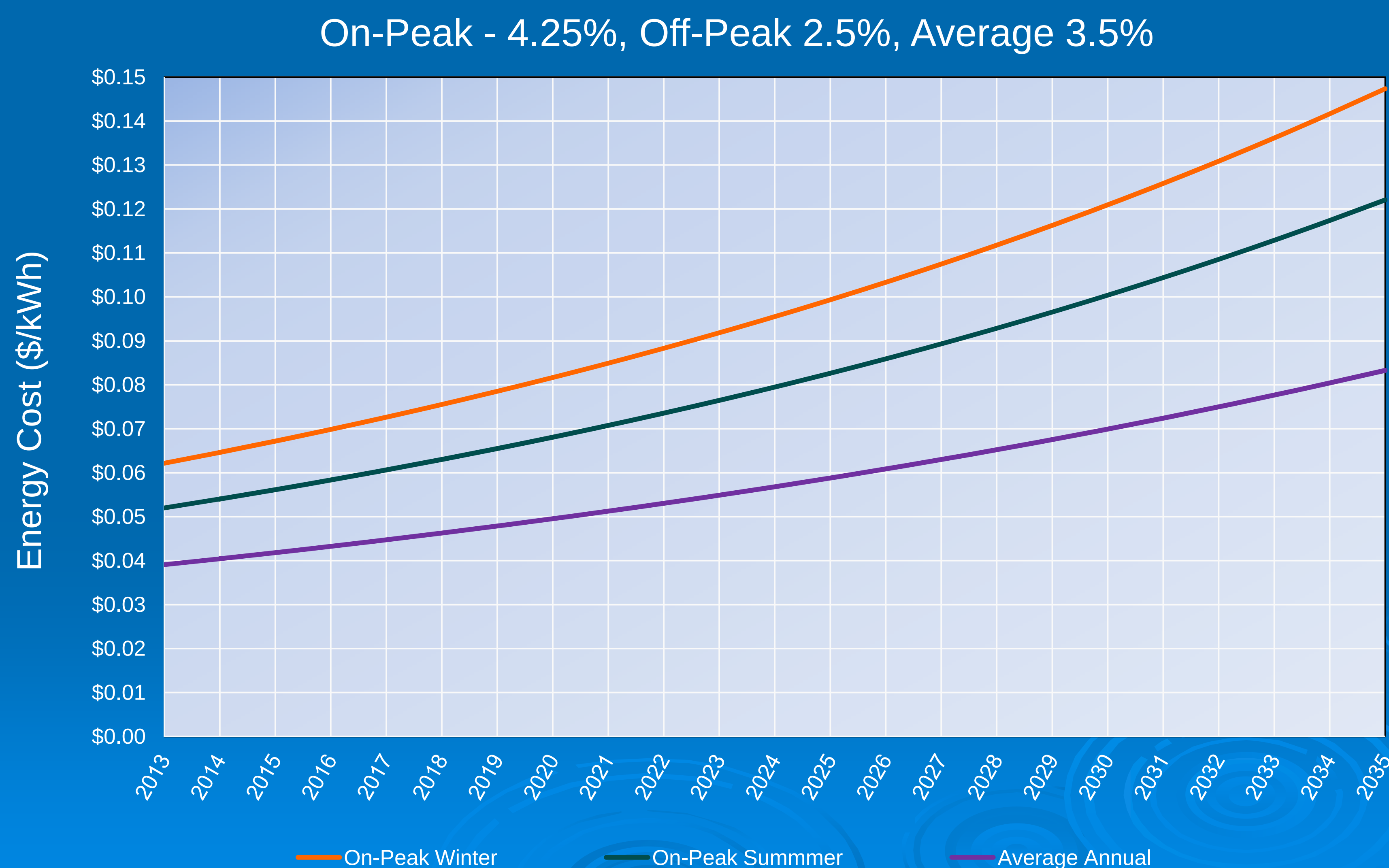
Note: Hourly Day-Ahead MISO Market Pricing Does Not Include Transmission Charges

Rate Strategy (Energy)

On-Peak - 4.25%, Off-Peak 2.5%, Average 3.5%



Rate Strategy (Energy/Demand)



Customer TOU Impacts

- Bill Impacts are Related to Consumption Behavior
  - Consumption load factor (more energy-centric rate design)
  - On-Peak to Off-Peak energy consumption ratios
  - Seasonal Winter to Summer energy consumption ratios
- Contracts May Impact Minimum Billing Demand
  - 50 percent minimum demand bill relates to contracted capacity
  - Addresses transmission and distribution capacity constraints
  - Relates to reserved transmission and distribution capacity
- Larger Bill Impacts Addressed by Contract Revisions
  - Contracted capacity levels relative to actual consumption levels
  - Opportunity for customer to reserved capacity (at a known cost)
  - Addresses changing economy and constraints in MH system

Customer TOU Impacts

(Standard Rates .vs. Indicative April 1, 2013 TOU Rates)

	Number of Customers	
	Large 30 – 100kV	Large >100kV
Decrease > 5%	2	2
Decrease 3% – 5%	5	2
Decrease 1% – 3%%	11	2
Increase or Decrease <1%	5	4
Increase 1% – 3%	5	1
Increase 3% - 5%	6	0
Increase > 5%	3	1
Total Customers	**37**	**12**

Time-of-Use Conclusions

- Time-of-Use Addresses Many Rate Design Concerns
  - Provides broad applicability to all customers within rate class
  - Eliminates challenge of baseline determination (industrial)
  - Ensures equitable treatment of all consumption and growth
  - Enables customers to load-shift with minimal rate impediment
  - Provides strong on-peak conservation stimulus for industry
- Reduces Impediments to Industrial Economic Growth
  - Provides for revenue neutral implementation of new structure
  - Preserves Manitoba's favorable average industrial power rates
  - Provides reasonable access to lower cost off-peak energy
  - Accommodates customers with favorable load profiles
  - Addresses impact of high load-factor, energy-intensive growth

Time-of-Use Conclusions

- Short-Term MISO Market Has Changed Since 2008
  - Reduced demand for energy coupled with low natural gas rates
  - US-CDN exchange rates have decreased and stabilized
  - On/off peak price ratios have remained relatively constant
  - Seasonal ratios have fluctuated due to economic conditions
  - Time-of-Use rate design is reflective of market price signals
- Provides a Market Relative On-Peak Price Signal
  - Representative of higher-value energy during on-peak periods
  - Provides flexibility in future rate design for market changes
  - Provides some degree of on-peak export revenue protection

GAC/MH I-25

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 6:

a. Please provide the derivation of the proposed demand charges.

ANSWER:

The proposed demand charges reflect 50% of the current demand charges with the remaining revenue to be collected in on-peak energy charges. The proposed demand charge was selected to reduce impediments to load shifting and to increase the energy price signal in the on-peak period to better reflect current export contract levels applicable in the on-peak period.

GAC/MH I-25

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 6:

b. Please demonstrate that 50% of these charges times the contract demand "Addresses transmission and distribution capacity constraints," and "Relates to transmission and distribution capacity reserved by customers." (slide 16)

ANSWER:

Current General Service Large rates presently provide for a minimum monthly billing demand of 25 percent of a customer's contract demand or peak monthly demand in the previous 12 months. This price signal has proven to be inadequate to persuade customers with very low monthly demand levels (relative to their reserved contract demand) to restate their contract demand despite maintaining these low demand levels for sustained periods of time .

Manitoba Hydro is concerned that unused capacity reserved by customers through their specified contract demand levels may impede the Corporation's ability to serve new and/or expanding load with existing transmission infrastructure, resulting in potential costs for new infrastructure that would not be required if unused capacity was released. Contractually, customers have historically not been required to release unused capacity in order for Manitoba Hydro to serve other load (i.e. new/expanding customers, firm export sales, etc).

The intent of the revised minimum monthly billing demand is to send a stronger price signal to customers in regards to the cost of unused capacity to Manitoba Hydro.

The 50 percent minimum monthly billing demand ratchets may result in billing increases ranging from 5 to 15 percent for customers that operate at very low demand levels relative to their specified contract demand. This proposed change to the demand ratchet creates an incentive for customers to restate contract demands to levels to be more proportional to their actual demand levels, which would serve to mitigate the potential billing increase.

GAC/MH I-26

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slides 7–9 and 11–13:

a. **Please provide the hourly data underlying the top portions of the slides, in Excel-readable format.**

b. **Please explain whether Hydro believes that time-of-use pricing should be based on historical pattern in US$ or CDN$.**

ANSWER:

a. The hourly data used to develop the aggregated energy prices shown in slides 7-9 and 11-13 reflects the application of hourly market pricing at the Manitoba Hydro delivery point (without transmission charges). Given the file size of the data set requested, Manitoba Hydro will provide an Excel spreadsheet only, and will not prepare hard copies.

b. The MISO pricing was stated in USD, while the Time of Use rates were quoted in CAD. The intent of the representation was to remove the impact of currency fluctuation and show that the proposed Time of Use rates exhibited similar on-off peak price ratios and seasonal price ratios to those historically present in the market.

GAC/MH I-27

a) With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 10:

a. Please provide the data underlying the graph, and the computation of the US$ prices from CDN$ prices.

ANSWER:

The exchange rates used to develop the graph in Slide 10 of the stakeholder presentation on August 15th were based on the noon-day exchange rate on the final day of the preceding month. The MISO USD hourly day-ahead prices for the following month were then multiplied by the noon-day exchange rate to determine the equivalent CAD hourly day-ahead price.

Please see the attachment to this response.

US-CDN Exchange Rates

Noon-Day	US$toCDN$
31-Mar-05	1.20960
30-Apr-05	1.25690
31-May-05	1.25100
30-Jun-05	1.22560
31-Jul-05	1.22590
31-Aug-05	1.18890
30-Sep-05	1.16110
31-Oct-05	1.18010
30-Nov-05	1.16740
31-Dec-05	1.16590
31-Jan-06	1.14390
28-Feb-06	1.13800
31-Mar-06	1.16710
30-Apr-06	1.12030
31-May-06	1.10280
30-Jun-06	1.11500
31-Jul-06	1.13090
31-Aug-06	1.10660
30-Sep-06	1.11530
31-Oct-06	1.12270
30-Nov-06	1.14150
31-Dec-06	1.16530
31-Jan-07	1.17920
28-Feb-07	1.17000
31-Mar-07	1.15290
30-Apr-07	1.10670
31-May-07	1.06990
30-Jun-07	1.06340
31-Jul-07	1.06570
31-Aug-07	1.05640
30-Sep-07	0.99630
31-Oct-07	0.94990
30-Nov-07	1.00080
31-Dec-07	0.98810
31-Jan-08	1.00220
29-Feb-08	0.97980
31-Mar-08	1.02790
30-Apr-08	1.00950
31-May-08	0.99420
30-Jun-08	1.01860
31-Jul-08	1.02570
31-Aug-08	1.06260
30-Sep-08	1.05990
31-Oct-08	1.21650
30-Nov-08	1.23720

US-CDN Exchange Rates

Noon-Day	US$toCDN$
31-Dec-08	1.22460
31-Jan-09	1.23640
28-Feb-09	1.27070
31-Mar-09	1.26020
30-Apr-09	1.19400
31-May-09	1.09610
30-Jun-09	1.16250
31-Jul-09	1.07900
31-Aug-09	1.09670
30-Sep-09	1.07220
31-Oct-09	1.07740
30-Nov-09	1.05740
31-Dec-09	1.04660
31-Jan-10	1.06500
28-Feb-10	1.05260
31-Mar-10	1.01560
30-Apr-10	1.01160
31-May-10	1.04620
30-Jun-10	1.06060
31-Jul-10	1.02900
31-Aug-10	1.06390
30-Sep-10	1.02980
31-Oct-10	1.01880
30-Nov-10	1.02640
31-Dec-10	0.99460
31-Jan-11	1.00220
28-Feb-11	0.97390
31-Mar-11	0.97180
30-Apr-11	0.94860
31-May-11	0.96880
30-Jun-11	0.96430
31-Jul-11	0.95380
31-Aug-11	0.97840
30-Sep-11	1.03890
31-Oct-11	0.99350
30-Nov-11	1.01970
31-Dec-11	1.01700
31-Jan-12	1.00520
29-Feb-12	0.98660
31-Mar-12	0.99910
30-Apr-12	0.98840
31-May-12	1.03490
30-Jun-12	1.01910

GAC/MH I-28

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 16:

a. **Please explain how frequently each customer would be allowed to revise its contract demand level.**

b. **Please explain the meaning of "Opportunity for customer to reserved capacity (at a known cost)."**

c. **Please explain how contract revisions "Address changing economic conditions…in MH system."**

d. **Please explain how contract revisions "Address changing… constraints in MH system."**

e. **Would Hydro be able to decline to revise contracts if the excess transmission and distribution capacity created by a customer's demand reduction would not be used by other customers?**

ANSWER:

a) Contracted demand levels are specified in Manitoba Hydro's Supply Agreement with large customers. The duration of this Agreement is negotiated when the customer initially obtains service and at subsequent renewals thereafter. Customers have the right to approach Manitoba Hydro at any time after a negotiated period with a request to renegotiate the terms of their Supply Agreement. Clause 4 a) from the Supply Agreement is included below as reference :

> *4. (a) The Customer may at any time after a date which is ____ billing year(s) calculated from the 30th day of November next following the commencement date, by notice to Manitoba Hydro, decrease the amount of contracted power. The effective date of the decrease shall be the 1st day of December of the billing year next following the date of the notice, provided that notice is given to Manitoba Hydro at least 60 days prior to the start of the billing year, otherwise the effective date shall be the 1st day of December of the second billing year following the date of the notice.*

Customers may also request increases to their contracted demand level at any time as specified in Clause 3 of the Supply Agreement, which is provide below for reference:

> *3. The Customer may by notice to Manitoba Hydro request an increase in the amount of Contracted Power together with the energy supplied with such excess power, at any time, and Manitoba Hydro will use its best endeavours to supply the increased amount of power and energy requested by the date it is required by the Customer, on terms and conditions applicable to Customers in the rate classification in which the Customer will be following such increase.*

Customers may however incur significant costs for access to higher contracted demand levels based on the costs for providing that capacity from Manitoba Hydro's generation and transmission system.

b) Manitoba Hydro is contractually obligated to provide power up to a customer's contract demand. Manitoba Hydro's current General Service Large rate structure includes a minimum monthly demand charge that is defined as the highest of actual recorded demand, 25% of contract demand or 25% of the highest recorded demand in the past 12 months. This billing threshold provides minimal incentive for most large customers to reduce their contracted demand levels if significant contracted capacity remains unused. The change in the demand ratchets from 25% to 50% proposed in the Application would result in some customers paying a contribution toward the unused capacity specified in their Supply Agreement.

Based on historic demand levels, these customers may choose to reduce their contracted demand in order to reduce their demand charges, or they may choose to retain their contracted demand level and reserve this capacity on Manitoba Hydro's generation and transmission system at a known cost based on the monthly demand charge.

c) Changing economic conditions in the market may have long term implications for customer operations, positively or negatively impacting usage requirements relative to contracted demand levels. The present General Service Large rate structure provides no premium for unused capacity above 25 percent of contracted demand levels, so customer may continue to retain their contracted demand levels even if there is no expectation to utilize that capacity in the future. The time-of-use rate proposal increases that threshold to 50 percent of contracted demand, providing some return to Manitoba Hydro for committed capacity that is not utilized.

d) Manitoba Hydro is facing increasing capacity constraints in its generation and transmission system. Capacity reserved by customers in their Supply Agreements is considered to be a firm capacity commitment that must be met under all conditions. Unused capacity therefore places a requirement on Manitoba Hydro to provide for firm supply at a time when capacity constraints may be forcing the Corporation to incur significant expenditures to meet new load growth. Increasing the minimum monthly demand charge to 50% of a customer's contract demand, provides an incentive for customers to release unused capacity.

e) Under the present terms of the Supply Agreement such a request could not be denied after the negotiated period specified in Clause 4. (a) as noted in the response to item a) of this question.

For the reasons noted in response to part (d), Manitoba Hydro encourages customers with unused capacity, to reduce their contracted demand.

GAC/MH I-29

With regard to Hydro's August 15, 2012 stakeholder presentation on General Service Large time-of-use rates, slide 18:

a. **Would "Manitoba's favorable average industrial power rates" continue to "attract energy-intensive load to Manitoba" (slide 2)? If so, how would time-of-use rates solve the problems described on slide 2?**

b. **Please explain how the proposed time-of-use rates would "Addresses impact of high load-factor, energy-intensive growth."**

ANSWER:

a) The introduction of Time-of-Use rates will not entirely eliminate the risk that Manitoba Hydro's favorable average industrial power rates will continue to attract energy intensive load to Manitoba. Time-of-Use rates do however provide a clearer price signal to prospective energy-intensive loads regarding the value that firm export sales of on-peak energy provides to Manitoba Hydro and its domestic ratepayers.

b) It is anticipated that a strong on-peak Time-of-Use price signal will support load shifting and off-peak operation as key considerations for existing and prospective energy intensive customers, which will support enhanced firm export opportunities for Manitoba Hydro. Integrating Time-of-Use considerations into the planning process for new industrial facilities will support the potential for load shifting, enhancing firm export opportunities for Manitoba Hydro in the long term.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

c) Load Shifting

Please provide MH's forecast on load shifting/revenue losses that could flow from; lower off-peak rates for energy and demand charge reductions.

ANSWER:

Load shifting from the higher cost on-peak period to the lower-cost off-peak period would result in lower domestic revenues being provided to Manitoba Hydro from the General Service Large >100 kV and 30 – 100 kV rates classes. The degree of load shifting that customers may undertake is impacted by several factors, including the availability of capacity in the off-peak period, either through a customer's electric supply contract or within the production capabilities of their facility, load factor, and the minimum monthly contract amount (50 percent of contract). Given these constraints, there are some limitations to the degree of load shifting that can occur in the short-term.

Manitoba Hydro has not forecast load shifting and revenue losses that could flow from load shifting. A sensitivity analysis undertaken on 2011-12 consumption profiles, which applied present contract demand limits to off-peak demand growth, yielded a maximum theoretical industrial load shift of approximately 100 MVA and 300 GWh (approximately 5 percent of the total industrial consumption served at greater than 30 kV). The sensitivity analysis did not take into account limitations in customer processes and off-peak production capacity. Based on customer feedback, these limitations will dramatically reduce the potential opportunity for load shifting in the short term, requiring significant capital investment to adjust processes and add off-peak capacity in the long-term.

The determination and impact of revenue gain/loss determination would be dependent on the additional revenue that could be obtained from the sale of freed on-peak capacity to other domestic customers and export markets. The firmness of this freed capacity will be established over the first two to three years of time-of-use implementation. Significant load shifting should also reduce Manitoba Hydro's net cost to serve these customers over the long-term.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

e) Energy Intensive Industry Rates (EIIR)

Please confirm that IFF11 does not include any EIIR revenues and explain why MH is no longer pursuing an EIIR process.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-113(b).

Manitoba Hydro has determined that introduction of a Time-of-Use rate, with on peak prices set to approximate firm values in the export market, provides some protection of export revenue, offers the opportunity to track market prices for firm energy sales in the long run and addresses the key criteria set forth in Order 112/09.

The introduction of a TOU rate enables Manitoba Hydro to provide more appropriate price signals to large energy users, providing a clear indication of the value of energy to Manitoba Hydro while maintaining revenue neutrality and preserving Manitoba's competitive industrial rate position relative to other provinces and states. Such a rate also partially addresses Manitoba Hydro's concerns about load growth by energy-intensive industries and the potential impact that such growth may have on profitable on-peak export sales through the creation of a rate structure that is representative of the pricing trends and behavior in the MISO power market, particularly during the on-peak period.

The TOU rate design provides greater flexibility in rate application, such that the on-peak rate can be tailored to more closely track the value of long term firm export energy, thereby creating an implicit link to market-based rates without the complexity and instability in pricing that market-based rates typical demonstrate. The proposed TOU rate is also simpler to implement and administer than alternative rates, such as inverted rates or rates applied to load expansions only, which require complex determination of baselines and application of two-tier rates.

Finally the TOU rate design addresses all of the criteria set forth in PUB Order 112/09. The criteria were summarized on page 137 of that Order.

1) Applies to all non-government GSL>30 customers.
The proposed TOU rate will apply to all customers served at > 30 kV, including government customers.

2) EIIR only applicable to on-peak load growth above an existing aggregated baseline.
The proposed TOU rate will apply to all usage of all customers served at > 30 kV. There will be no baseline calculation.

3) Baseline adjustments will only be permitted relative to Curtailable Rates Program; Self-Generation and mandated energy efficiency.
Since there are no baselines, there will be no baseline adjustments.

4) Proxy rate of 5.53 cents/kW.h adjusted downward by 0.9 cents/kW.h to remove the demand component, to apply for the initial three year test period.
The proposed TOU on peak rate is seasonally differentiated at 4.2 cents for non-winter and 5.2 cents for winter months. On a weighted average basis the energy rate is 4.53 cents per kW.h (GS large > 100 kV) which is very close to that directed in Order 112/09.

5) New to Manitoba GSL>30 customers are entitled to 50% of on-peak energy at embedded cost rates, for a period of three years, after which an adjustment may be made.
The TOU rate will apply to all usage by all customers, existing or new, hence it is both simple and fair.

GAC/MH II-30

Subject: **Rate Design—Proof of Revenue**
Reference: **Appendix 10.12**

b) **For each rate and sub-rate class and for both the Interim 2012 rates and Proposed 2013 rates, please provide the number of billing demand units that are attributable to the demand ratchets.**

ANSWER:

Manitoba Hydro does not aggregate forecasted billing demand units into ratchet/non-ratchet components. Forecasted billing demands are estimated based on historical aggregated class load factors for Mass Consumers and individual historical load factors for Top Consumers. The total forecasted billing demand units used in deriving class revenue for the 2013/14 test year (Appendix 10.12) are the same regardless of which rates were applied. The billing demand units forecasted are as follows (as provided in response to MIPUG/MH I-20(b) page 4):

Large 30-100 = 2,545,857 kVA
Large >100 = 8,890,008 kVA

The portion of these units attributable to demand ratchets would be relatively insignificant based on analysis of the 25% ratchets versus 50% ratchets on actual billing demand units for 2011/12. Based on this data, the table below provides the billing demand units (kVA) attributable to the 25% and 50% ratchets split between the "% of highest recorded demand in the previous 12 months" and "% of contracted demand".

	25% Ratchets			**50% Ratchets**		
	Highest	Contract	Total	Highest	Contract	Total
Large30-100	813	35,290	36,103	9,377	215,946	225,323
Large >100	0	23,310	23,310	6,545	96,504	103,049

The customers most impacted by the ratchets tend to be those who have over-contracted their loads. It is expected that these customers will revise their contract to more closely represent their actual usage. It is also important to recognize that with TOU rates, customers will be billed based on their highest recorded on-peak demand rather than their highest maximum demand (on or off peak). Based on the 2011/12 data, on-peak demand was 43,211 kVA lower than maximum demand for the Large 30-100 kV customers, and 53,040 kVA lower for the Large >100 kV customers. This may offset some of the effects of the higher ratchets for some customers.

GAC/MH II-32

Subject: **Rate Design—Proof of Revenue**
Reference: **Appendix 10.12**

Regarding the Proof of Revenue for the proposed Large General Service TOU rate, please provide documentation of the following:

b) the calculation of the billed on-peak winter energy, on-peak non-winter energy and off-peak energy.

ANSWER:

Historical billing data was used in determining the percentage of on-peak / off-peak / winter / non-winter energy usage for each of the classes. These percentages (as shown below) were then applied to the forecasted energy for each class to determine the TOU energy values for each test year.

Large >100 kV:	On-Peak Winter	16.6%
	On-Peak Non-Winter	28.5%
	Off-Peak	54.9%
	Total	100.0%
Large 30-100 kV:	On-Peak Winter	15.4%
	On-Peak Non-Winter	28.9%
	Off-Peak	55.7%
	Total	100.0%

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

a) Provide analyses, reports, internal memoranda and other documentation that indicate that in the past the Corporation has been impeded from making export sales because of unused but reserved transmission capacity.

ANSWER:

The intent of the minimum demand bill component of the Time-of-Use rate application is not explicitly directed towards opportunities for export sales. The minimum demand bill is intended to address the contribution of unused contracted capacity to regional transmission and sub-transmission constraints that impact costs for serving new domestic load.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

b) Explain how MH takes the contract demand of Large General Service customers into account in deciding whether it has energy and capacity available to serve "new and/or expanding load with existing transmission infrastructure."

ANSWER:

Contract demand is an important consideration in determining the available capacity on regional transmission stations and lines, which are constrained by their design and contingency limitations. Capacity reserved for a specific customer cannot be used to serve new or expanding load in the same regional transmission system, potentially causing a requirement for upgrades and expansion of the regional transmission system in order to serve other customers.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

c) Provide planning analyses, reports, internal memoranda and other documentation that show how MH takes into account the contract demands of large customers in determining its need for additional generation, transmission and distribution resources.

ANSWER:

Planning analyses, reports and internal memoranda related to the consideration of contract demands by large customers as they may impact Manitoba Hydro's ability to serve new or expanding load typically include sensitive commercial information related to customer names, loads and future requirements for capacity. In some cases, these studies are funded by customers and are subject to confidentiality agreements that prevent release of information specific to their operations. As such, these documents are not available for review.

The types of planning analysis and reports referenced in the question are typically initiated when customers (new or existing) approach Manitoba Hydro to request capacity for a new or expanding load. These studies review the regional transmission capacity available to serve the additional load and quantify improvements that will be required to serve this load if it comes to fruition.

Requirements for new generation and major transmission are typically addressed through the Power Resource Planning process, which considers forecasted load growth by all customers, including large transmission and sub-transmission customers that may impact capacity requirements for generation and major transmission.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

d) Provide analyses, reports, internal memoranda and other documentation that indicate that the current 25% ratchet will no longer provide an adequate efficiency incentive for the Large General Service customers on the proposed TOU rate.

ANSWER:

The minimum demand bill component of Manitoba Hydro's Time-of-Use rate application is not intended to address the end-use efficiency of customer loads. The measure is directed towards capacity that is contracted by customers but unused. Unused capacity in the regional transmission system impacts Manitoba Hydro's ability to serve new and expanding customers with existing resources, causing the Corporation to expend resources to enhance the capability of the regional transmission system in order to serve such load. Raising the threshold will result in more customers contributing towards the costs of providing capacity that is unused, sending a price signal that unused capacity on the regional transmission system has a cost to ratepayers, particularly if new transmission capacity must be provided to serve new or expanding load.

GAC/MH II-37

Subject: **Rate Design—Proposed TOU Rate for the Large GS Class**
Reference: **Appendix 10.11**

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

e) **Specify MH's contractual supply obligations to Large General Service customers with contract demands.**

ANSWER:

Manitoba Hydro's ongoing obligations extend to the provision of sufficient capacity and energy to serve the customer load up to the limitations specified by the contract demand. Customers seeking supply for new or expanding load are addressed in accordance with customer service policy, which specifies how Manitoba Hydro may allocate costs for providing this capacity to the customer.

Manitoba Hydro's contractual supply obligations to Large General Service customers in the rate classes impacted by the proposed Time-of-Use rate application are approximately 1,200 MVA.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

f) Explain whether the MH's peak load forecasts used for planning purposes reflects:

- **i) The projected peak demands of Large General Service customers;**
- **ii) The projected sum of the greater of each Large General Service customer's peak demand or ratchet percentage of contract demand;**
- **iii) The sum of the greater of each customer's peak demand or 100% of contract demand; or**
- **iv) Something else. If something else, please explain.**

ANSWER:

Manitoba Hydro's peak forecast reflects the estimated peak load of the Large General Service Sector. The peak forecast considers the customer's actual peak demand. It does not consider ratchet percentage or contract demand.

GAC/MH II-37

Subject: **Rate Design—Proposed TOU Rate for the Large GS Class**
Reference: **Appendix 10.11**

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

g) In MH's Cost-of-Service-Study estimate of the costs imposed by the Large General Service customers, please explain whether the load data MH uses reflects:

- **i) The projected peak demands of Large General Service customers;**
- **ii) The projected sum of the greater of each Large General Service customer's peak demand or ratchet percentage of contract demand;**
- **iii) The sum of the greater of each customer's peak demand or 100% of contract demand; or**
- **iv) Something else. If something else, please explain.**

ANSWER:

Load data used in the Cost of Service Study to allocate demand-related costs to GSL customers is based on forecast class coincident peak demands for transmission costs, and the class non-coincident peak demands for sub transmission costs. Contractual demand values are not considered in the study.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

h) Explain whether MH holds back energy from export sales based on contract demand levels.

ANSWER:

Manitoba Hydro does not hold back energy from export sales based upon contract demand levels.

On a day-ahead basis Manitoba Hydro forecasts the expected hourly energy needs of all domestic customers using statistical analysis. These forecasts are then adjusted to reflect any expected changes in the demand pattern for large industrial customers using information that has been provided by them. Using this forecast and after having made allowances for reserves, Manitoba Hydro participates in the MISO Day Ahead market to sell any surplus it anticipates, or to buy any shortage.

In real time, Manitoba Hydro updates is system load forecast continuously based upon actual usage in Manitoba and participates in the MISO Real Time market to balance its supply to demand.

GAC/MH II-37

Subject: Rate Design—Proposed TOU Rate for the Large GS Class
Reference: Appendix 10.11

Regarding Manitoba Hydro's justification of its 50% ratchet proposal as a way to "encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve," please provide the following:

i) Indicate whether MH sells firm capacity to the United States or other provinces.

  - **i) If so, specify the contractual supply obligations of MH to these customers.**
  - **ii) If so, explain how the rates for this firm capacity are structured.**

ANSWER:

Manitoba Hydro confirms that it sells capacity to wholesale customers outside of Manitoba.

Please see Manitoba Hydro's response to CAC/MH I-115(a) for the list of export contracts Manitoba Hydro is currently committed to. The capacity provided under these contracts is not firm capacity (i.e. backed by Manitoba Hydro capacity reserves) but rather it is system participation power. With this type of power the export customer is exposed to certain curtailment risks associated with higher priority loads and system conditions specified in the contract.

The rates for capacity are structured as a dollar amount per MW-month which apply to the contracted amount of capacity.

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

a) Please indicate if the percentage rate impacts referenced at page 5 remain consistent with the rate impacts estimated at page 18 of Attachment 1 to GAC/MH-1-24(c). If not, please provide an updated table similar to page 18 of Attachment 1 to GAC/MH-1-24(c). For those customers in excess of 5% in the table, please provide each specific rate impact percentage.

ANSWER:

The percentage rate impacts related to implementation of Time-of-Use rates for General Service Large customers served at greater than 30 kV referenced on page 5 of Manitoba Hydro's October 3rd, 2012 letter were determined relative to the interim approved September 1, 2012 General Service Large rates. The Time-of-Use rate impact estimates provided on page 18 of Attachment 1 to GAC/MH I-24 c) were determined based on a comparative April 1, 2013 rate using the present General Service Large rate structure with an average 3.5 percent class rate increase, to be collected entirely through increasing the energy rate.

Rate impacts for customers identified as having a rate increase of greater than 5 percent on Page 18 as a direct result of the implementation of Time-of-Use rates are listed below:

General Service Large > 100 kV

Customer 1	6.8%

General Service Large 30 – 100 kV

Customer 1	7.6%
Customer 2	5.6%
Customer 3	8.4%

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

b) Please indicate how Manitoba Hydro will apply the 50% demand charge to

- **i. Companies in the process of ramping up operations, with signed contracts for demand well above what they are using in the initial operation phases.**
- **ii. Companies with seasonal or intermittent shut-down periods.**
- **iii. Companies in the process of scaling back operations temporarily in response to economic downturns.**
- **iv. Companies which employ intermittent load management strategies such as self-generation or demand side management practices to reduce their loads.**

ANSWER:

i) Manitoba Hydro attempts to coordinate timing of supply agreements to the time frame in which customer load is commissioned and brought into service on the Manitoba Hydro system. This process recognizes the lead times for making improvements to the Manitoba Hydro system in order to provide the customer with additional capacity and related customer work required to construct facilities and install equipment that will be adding load on the Manitoba Hydro system.

In instances where customers are requesting capacity to be added well in advance of plans to place load on the Manitoba Hydro system and required system improvements have been undertaken by Manitoba Hydro, customers will be bound to the minimum 50 percent of contract demand provision stated in Manitoba Hydro's Time-of-Use rate application.

ii) Customers with seasonal or intermittent shut-down periods will be bound to the terms in Manitoba Hydro's Time-of-Use rate application, specifying a minimum demand bill equal to 50 percent of contract demand. The lower demand rates specified in the Time-of-Use rate application will generally reduce customer costs during these periods relative to the present rate structure, which has a lower minimum demand bill percentage but a higher demand rate.

iii) Similar to the response provided in ii), customers would be subject to the terms specified in Manitoba Hydro's Time-of-Use rate application. It should be noted that the lower demand rate specified in the Time-of-Use application will generally reduce customer's fixed costs when scaling back operations. Prior experience under these circumstances shows that customers are generally not able to significantly scale back peak demand when curtailing production. The lower demand rate specified in the time-of-use application will reduce monthly demand costs relative to present rates when customers scale back operations in response to economic downturns.

iv) In instances where customers implement demand side management practices that result in long term load reductions, the impact of the 50 percent of contract demand could be mitigated by reducing specified contract demands. In instances where customer-owned, self generation displaces customer load to levels below the 50 percent of contract threshold, examination of the circumstances will need to be undertaken to establish whether contract levels can be revised, thereby solidifying the long-term benefit to Manitoba Hydro, or whether requirements exist for the customer to retain the specified contract capacity for redundancy or back-up, which require Manitoba Hydro to maintain the higher capacity level.

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

c) Please provide a list of all measures considered by Manitoba Hydro as alternatives to the 50% of contract demand charge ratchet to address the concern noted at page 2 of Manitoba Hydro's October 3, 2012 letter; i.e., "that unused capacity, reserved by customers through their specified contract demand levels, may impede the Corporation's ability to serve new and/or expanding load with existing transmission infrastructure, resulting in potential costs for new infrastructure that would not be required if unused capacity was released." For each measure, please provide a comparison of the impacts on the number of customers affected, the magnitude of impacts on target customers, any impacts on Hydro's revenues, and a comparison of the likely effectiveness of each approach to addressing the issue of contracted but unused capacity.

ANSWER:

Manitoba Hydro considered the application of an unused capacity charge at a reduced demand rate for the unused capacity between the specified contract demand and actual monthly on-peak demand as an alternative to the 50 percent minimum contract demand charge.

Reduced rate demand charges of $1.00 per kVA, $1.50 per kVA, and $2.00 per kVA were examined for application to the difference between the specified contract demand and actual monthly on-peak demand in order to determine the impact on customers with un-used capacity and establish the potential impact on Manitoba Hydro revenues.

The scope and number of customers impacted by this approach would have been considerably larger than the proposal filed in Manitoba Hydro's Time-of-Use rate application, since the majority of customers do not fully utilize their contract capacity. To mitigate the extent of this impact, a threshold equal to 90 percent of contract demand was considered as a limit for applying the lower unused capacity charge, with customers operating at greater than 90 percent of contract not being impacted.

The range of customer impacts for the $1.00, $1.50, and $2.00 per kVA demand charge for unused capacity using the 90 percent threshold level are noted below. Manitoba Hydro revenue impacts are compared to the Time-of-Use rate application.

Unused Demand Charge ($/kVA)	Customers # < - 5%	Customers -5% > # < 0%	Customers 0% < # < 5%	Customers # > 5%	Manitoba Hydro Revenue Impact
General Service Large > 100 kV					
$1.00	1	6	5	0	$762,591
$1.50	0	4	7	1	$1,289,815
$2.00	0	4	6	2	$1,817,038
General Service Large 30 – 100 kV					
$1.00	3	12	15	5	$870,532
$1.50	2	7	15	11	$1,596,154
$2.00	2	6	13	14	$2,321,776

Adoption of these measures would have had similar types of impacts to the proposed adoption of the 50 percent of contract demand provision in Manitoba Hydro's Time-of-Use rate application. The effectiveness of the measure would have been dependent on the magnitude of the impact felt by each individual customer, with impacts increasing as the charge for unused capacity increased, the greater impacts creating increased awareness about the impact of unused capacity. Higher charges for unused capacity would have increased the number of customers impacted and therefore created greater awareness.

The 50 percent of contract demand provision was proposed for Manitoba Hydro's Time-of-Use rate application for ease of application and similarity to current minimum demand bill provisions in the present rate, easing customer understanding of the measure.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

c) For each customer in part (b), please indicate the efforts Hydro has made to have the customer release persistently unused contract demand, and over what period these efforts have been made.

ANSWER:

Supply agreements for larger customers are reviewed by Manitoba Hydro's Key and Major Account Energy Service Advisors on a periodic basis as loads change and contracts are identified for review and renewal. Customers who have not utilized their contract demands are informed and discussions are had regarding their short and long term capacity needs. Legacy supply agreements do not require customers to release contracted capacity and at present, there is minimal incentive for customers to relinquish capacity, as there is no specific penalty or incentive for them to release unused contract demand.

CAC/MSOS/MH I-190

Subject: **General Service Rates**
Reference: **Appendix 13.6**

a) Does Manitoba Hydro have a timetable as to when a determination will be made regarding the future application of time of use rates for General Service Large and/or seasonal rate differentiation for General Service Medium and General Service Small Demand customers? If yes, please describe.

ANSWER:

Manitoba Hydro is presently reviewing TOU rates on the General Service Large customers and is currently in discussions with customers regarding an Energy Intensive Industrial rate (EIIR) which has a TOU component built into the design. An Application on the EIIR was filed with the Public Utilities Board on February 12, 2010.

No analysis has been undertaken with respect to TOU rates for General Service Medium and Small Demand customers. The majority of these customers do not have interval metering in place to record time period usage.

<u>PUB/MH I-196</u>

Subject: **Tab 13: PUB Directives**

Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

a) Please indicate the basic rationale which justifies elimination of the Winter Ratchet for GSM in the class consolidation process.

<u>ANSWER</u>:

To fully consolidate the General Service Small and Medium rate classes requires that they be charged identical rates and the same application of those rates. As indicated in the Small / Medium Class Consolidation report filed with the PUB in July 2009 (included as Appendix 13.8 of this Application), the only differences between the rates of Small and Medium customers was the Monthly Basic Charge, first block Energy Charge and application of the 70% winter ratchet.

With the rates proposed in this Application only the monthly Basic Charge differs between the two classes, which, depending on future rate proposals, could take one or two more rate changes to fully consolidate. The Energy rates proposed are now the same for both classes and the 70% winter ratchet has been eliminated as of December 1, 2009. Prior to its elimination, only a Medium Demand customer was subject to the 70% ratchet provision.

<u>PUB/MH I-196</u>

Subject: **Tab 13: PUB Directives**

Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

b) What are the anticipated RCC impacts going forward to 2013:

i. With the 70% Winter Ratchet still in place?

ii. Without the Winter Ratchet?

<u>ANSWER</u>:

Manitoba Hydro collected approximately $2.5 million annually from the winter ratchet, of which over 80% was from the GSM class. In the absence of this revenue Manitoba Hydro would have to increase other charges to collect this revenue when designing rates and the revenue requirement of each class. Typically this recovery would be in a higher energy charge. In this Application, as discussed in Tab 10, Manitoba Hydro has replaced the revenue through higher proposed energy charges; as a result there is no impact to the class RCC.

<u>PUB/MH I-196</u>

Subject: **Tab 13: PUB Directives**
Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

c) Please provide the rationale and justification that would support a PUB approval of the elimination of the 70% winter ratchet.

<u>ANSWER</u>:

Manitoba Hydro eliminated the 70% winter ratchet in response to Order 116/08 wherein it stated at page 355: "*Unless MH provides an acceptable TOU implementation process, the ratchet is to be removed ahead of the winter of 2009/10*".

PUB/MH II-144

Subject: **Tab 13 Board Directives**
Reference: **December 18, 2009 MH Letter to PUB; February 2010 Report/Attachment #1; August 7, 2009 Application**

a) **Please indicate which (if any) of the 53 to 67 eligible customers and 17 to 25 approved customers were previously subject to the winter ratchet for billing demand determination.**

ANSWER:

None of the 53 - 67 eligible customers or 17 - 25 approved customers were subject to the winter ratchet for billing demand during the 24 month period used to determine the baseline for the Billing Demand Deferral program.

<u>PUB/MH II-145</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-165 (a) Pages 3 and 4 of 6, Demand Billing Reductions**

a) **Please confirm that hypothetical elimination of the 70% winter ratchet as of June 1, 2009 would have given 2 GSL >100 KV customers a billing reduction of $723,000 or about 70% of what might have been granted if their demand concession application were fully approved.**

<u>ANSWER</u>:

Hypothetical elimination of the 70 percent winter ratchet as of June 1, 2009 would have given two General Service Large (>100 kV) customers a billing demand reduction of approximately $645,000.

PUB/MH II-145

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-165 (a) Pages 3 and 4 of 6, Demand Billing Reductions**

b) **Please confirm (and quantify) that going forward from December 1, 2009, these two and possibly other customers may see a substantial bill reduction if their monthly demand levels continue at 25% or less of past averages.**

ANSWER:

These two customers would have continued to see similar monthly billing demand reductions as determined in response to PUB/MH II-145(a) if their measured demand levels had remained at the levels recorded during the program period. The amount of these billing demand reductions would have been approximately $220,000 per month.

Other customers would have seen billing demand reductions as well if their measured demand levels had remained at the levels recorded during the program period. The amount of these billing demand reductions would have been approximately $20,000 per month.

PUB/MH II-146

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-181(d) - Recent Demand Billing Rates**

b) Please provide a breakdown for each subclass and industry sector of the "foregone revenue from demand charge increases" that the accumulated (from F2004-F2009) rate increases would theoretically have permitted on an across-the-board basis.

ANSWER:

The table included below provides the calculated cumulative demand revenues from 2004/05 to 2008/2009 for all demand-billed rate classes had rate increases been applied equally to the demand and energy portion of the rate. For each year demand revenue at the April 2004 approved kVA rate was compared with demand revenue calculated at an adjusted demand rate which incorporated that year's rate increase, if any. The adjusted Demand rate incorporated the cumulative rate increases for the period August 1, 2004 to March 31, 2009 multiplied by the 2004 Demand rate.

Over the 5 year period $68.9 million in additional revenue would have been collected through increased demand charges. In the absence of these higher demand charges the revenue was collected instead through higher Energy Charges, which as a result, were higher in order to compensate for the static Demand Charges.

It is impossible to provide a breakdown of the information by industry sector as Manitoba Hydro does not provide revenue forecasts by industry type for all customer classes.

	Apr-04 kVa Rate	Adj 09 kVa Rate	Cumulative Increase	2010/11 kVa Rev @ Current	2010/11 kVa Rev @ Revised	Difference
Small	$8.32	$9.59	13.24%	$86,758,847	$94,141,764	$7,382,917
Medium	$8.32	$9.59	13.24%	323,421,688	350,310,283	26,888,596
Lrg <30	$7.09	$8.17	13.24%	125,189,620	135,843,363	10,653,742
Lrg 30-100	$6.05	$6.97	13.24%	53,793,795	58,424,453	4,630,657
Lrg >100	$5.40	$6.23	13.24%	228,111,721	247,453,697	19,341,976
				$817,275,671	$886,173,560	$68,897,889

CAC/MSOS/MH I-1

Subject: **Letter of Application**
Reference: **Tab 1, page 2**

Preamble: **Reference is made to reducing the BMC in both 2010 and 2011 in order to assist low income customers with low metered monthly consumption.**

a) Please confirm that these changes will increase the monthly bills for low income residential customers with higher than average monthly use.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-220(b) which compares the proposed Residential rate (which reflects a lower Basic Charge and higher tail block energy charge) to the revised Residential rate as per Order 18/10.

CAC/MSOS/MH I-1

Subject: **Letter of Application**
Reference: **Tab 1, page 2**

Preamble: **Reference is made to reducing the BMC in both 2010 and 2011 in order to assist low income customers with low metered monthly consumption.**

b) **Does Manitoba Hydro have any information on the monthly electricity usage of low income residential customers, as to whether they typically use more or less electricity than the average residential customer?**

ANSWER:

Low income residential customers typically use less electricity than the average.

For electrically heated customers, the average electricity use for the LICO sector is 20,466 kW.h, the average electricity use for the LICO-125 sector is 21,116 kW.h and the average electricity use for all customers is 25,868 kW.h.

For non-electrically heated customers, the average electricity use for the LICO sector is 6,782 kW.h, the average electricity use for the LICO-125 is 7,250 kW.h and the average electricity use for all customers is 10,096 kW.h.

<u>CAC/MSOS/MH I-1</u>

Subject: **Letter of Application**
Reference: **Tab 1, page 2**

Preamble: **Reference is made to reducing the BMC in both 2010 and 2011 in order to assist low income customers with low metered monthly consumption.**

c) **Please explain why it was viewed as appropriate to adjust the rate design to assist low income residential customers with low metered monthly usage, when such an adjustment will have an adverse impact on low income residential customers with high monthly usage.**

<u>ANSWER</u>:

This strategy can positively benefit all lower income Manitobans. As noted, lower income customers with lower energy use due to the size of their home will immediately receive the benefit of the elimination/reduction of the basic charge (and will not be required to wait for landlord controlled energy efficiency initiatives). Lower income Manitobans with large, drafty, inefficient homes that fall within the larger use and therefore inverted tail block, can upgrade the efficiency of their home through the Lower Income Energy Efficiency Program.

CAC/MSOS/MH II-36

Subject: **Rate Design**
Reference: **RCM/TREE/MH I-7 b)**

a) **Please confirm that the table provided in the response also suggests that the demand rate for GSM and GSL<50 will have to increase at a faster pace than the respective energy charge. If not, why not?**

ANSWER:

Confirmed, subject to constraints that may be imposed by other rate design objectives and subject to changes that could arise subsequent to the independent review of Cost of Service methodology.

CAC/MSOS/MH II-68

Subject: Rate Design

Reference: RCM/TREE I-81 a) & d)

a) **Please provide a schedule that sets out the coincident and non-coincident load factors for all Residential consumers versus those for Low-Use Residential consumers. For purposes of the calculation please use the same definition of "coincident peak" as used in the allocation of Transmission costs.**

ANSWER:

Load Research Results Average 2008/2009
Corresponding to Highest 50 Winter Generation Peaks

	Winter CP LF	Relative Accuracy %
Residential Low Use	85.4%	30.24
Residential (including low use)	77.7%	3.96

Load Research Results Average 2008/2009
Corresponding to Highest 50 Summer Generation Peaks

	Summer CP LF	Relative Accuracy %
Residential Low Use	84.8%	29.70
Residential (including low use)	82.9%	6.30

Load Research Results Average 2008/2009
Corresponding to Highest 50 Overall Common Bus Peaks

	NCP LF	Relative Accuracy %
Residential Low Use	41.4%	26.36
Residential (Including low use)	46.2%	3.48

<u>CITY/MH SUPP-9</u>

Manitoba Hydro appears to be of the view that the "C" portion of the allocated costs should not be included when determining energy costs. The City disagrees for the following reason. Referring to Schedule B2 in PCOSS 11, the Residential Customer "unit cost/month" = $21.49. This covers the Customer portion of the Residential Asset Class. However, the proposed Basic Rate to cover this portion is only $6.85 (Rate Schedules Pursuant to Board Orders 18/10 & 30/10, March 29, 2010). The remainder of the customer portion is subsidized by both the energy rate increase and the Net Export Credit, which still fall short of the residential total cost. So the inclusion of the customer allocation portion in our previous rate analysis (which constitutes 11% of total customer costs) would appear to us to be justified. Please provide a justification of Manitoba Hydro's position.

<u>ANSWER</u>:

The allocated Customer costs should not be included in the calculation of the Energy unit cost for the A&RL class when attempting to compare against the Residential class's Energy unit cost which does not include Customer costs. While the comparison of the Basic Charge to the monthly unit cost from the PCOSS indicate that some Customer related costs are recovered in the Energy rate for the Residential class, that is a matter of rate design not cost allocation.

The Energy unit costs as shown in Schedule B2 of the PCOSS for Residential and A&RL are already comparable to the extent that both include Energy as well as all Demand related costs. However, the vastly different rate structures, usage patterns and other customer characteristics restrict the usefulness of such a comparison.

A comparison of the relative ratio of the Energy Charge to Energy Cost for the two classes, as attempted in CITY/MH I-16, is not possible as there is simply no Energy Charge for A&RL to use in such a comparison. A better metric for relative performance for the two classes is the RCC ratio, which incorporates all costs and compares to all revenue.

<u>MIPUG/MH I-19</u>

Rate Objectives

a) With respect to Rate Objective #1 (page 2 of Tab 10) please indicate how much longer Hydro anticipates attainment of this objective will take.

<u>ANSWER</u>:

Rate objective #1 states:

Manitoba Hydro's long-term target is to have all class Revenue Cost Coverage (RCC) ratios in the range of 95% to 105%, and further that all classes should be gradually moved toward RCC's of unity.

Manitoba Hydro intends to commission an independent review of the Cost of Service Study methodologies before relying on the results of the study for rate design. Once this independent review is completed, Manitoba Hydro will consider differential rate changes in the future to address this targeted zone of reasonableness (ZOR).

PUB/MH I-128

Subject: Tab 9: Demand Side Management
Reference: Tab 10 Residential Rate Increases

Please quantify and explain the impact of the proposed lower Basic Monthly Charge and higher second block energy rates on the full spectrum of low income customers including those with electric heat.

ANSWER:

The impact of the proposed lower Basic Charge and higher second block energy rate will be the same for bills of low-income customers as it is for non low-income customers.

Based on the proposed residential rates filed in Appendix 10.3 of the Application, customers who consume less than an average 835 kW.h per month (10,020 kW.h annually) will experience a rate decrease. Those consuming more than 835 kW.h per month will experience bill increases which rise as usage increases, as shown in the following table.

RESIDENTIAL 200 AMP & LESS

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.
0	$6.85	$5.85	($1.00)	-14.60%
10	$7.48	$6.49	($0.99)	-13.24%
20	$8.10	$7.12	($0.98)	-12.10%
40	$9.35	$8.40	($0.95)	-10.16%
60	$10.60	$9.67	($0.93)	-8.77%
75	$11.54	$10.63	($0.91)	-7.89%
80	$11.85	$10.95	($0.90)	-7.59%
100	$13.10	$12.22	($0.88)	-6.72%
125	$14.66	$13.81	($0.85)	-5.80%
150	$16.23	$15.41	($0.82)	-5.05%
175	$17.79	$17.00	($0.79)	-4.44%
185	$18.41	$17.63	($0.78)	-4.24%
200	$19.35	$18.59	($0.76)	-3.93%

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.
250	$22.48	$21.78	($0.70)	-3.11%
300	$25.60	$24.96	($0.64)	-2.50%
350	$28.73	$28.15	($0.58)	-2.02%
375	$30.29	$29.74	($0.55)	-1.82%
400	$31.85	$31.33	($0.52)	-1.63%
500	$38.10	$37.70	($0.40)	-1.05%
600	$44.35	$44.07	($0.28)	-0.63%
700	$50.60	$50.44	($0.16)	-0.32%
750	$53.73	$53.63	($0.10)	-0.19%
835	$59.04	$59.04	$0.00	0.00%
900	$63.10	$63.18	$0.08	0.13%
1000	$69.40	$69.93	$0.53	0.76%
1100	$75.70	$76.68	$0.98	1.29%
1200	$82.00	$83.43	$1.43	1.74%
1300	$88.30	$90.18	$1.88	2.13%
1400	$94.60	$96.93	$2.33	2.46%
1500	$100.90	$103.68	$2.78	2.76%
1750	$116.65	$120.56	$3.91	3.35%
2000	$132.40	$137.43	$5.03	3.80%
2500	$163.90	$171.18	$7.28	4.44%
3000	$195.40	$204.93	$9.53	4.88%
4000	$258.40	$272.43	$14.03	5.43%
5000	$321.40	$339.93	$18.53	5.77%

PUB/MH I-133

Subject: Tab 10: Proposed Rates And Customer Impacts
Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

a) **Please discuss and quantify the costs (both fixed and variable) that are theoretically to be recovered from the electric BMC.**

ANSWER:

Currently, the electric BMC for residential customers is $6.85, which recovers approximately 34% of the fixed customer related costs as determined in PCOSS10. If all fixed customer related costs were recovered through the BMC, Manitoba Hydro would need to increase its BMC to approximately $20 per customer per month (as per Appendix 11.1, page 16 of the Application). From a theoretical perspective a basic monthly charge is put in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. The costs recoverable through the BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

It is arguable that customer hook-up and usage is much less influenced by the level of the Basic Monthly Charge than the level of the Demand or Energy charges. Consequently, in a situation such as Manitoba Hydro's in which embedded costs are significantly lower than marginal costs, it is not unreasonable for fixed charges to under-recover relative to fixed costs, to assist in maintaining flexibility to move the more price elastic part of the rate structure, the energy charge, closer to marginal cost. A lower fixed charge and therefore a higher variable rate also assists in allowing the customer greater control over the level of their bill. Additionally, basic monthly charges are typically not well understood or accepted by customers. It is therefore not uncommon for utilities to set the level of the charge below the fully embedded customer costs, a trade off between establishing strictly cost based rates and the practical realities of providing customers with service.

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

c) **What percentage of the costs will be recovered under the proposed reductions to the electric BMC in this application?**

ANSWER:

The proposed residential BMC of $5.85 would recover 29% of the $20.38 fixed customer related costs as determined in PCOSS10 (Appendix 11.1, page 16).

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

d) **Please quantify the costs both fixed and variable that are theoretically to be recovered from Gas operations and the percentage of those costs currently recovered in the Gas BMC.**

ANSWER:

The $14.00 Gas BMC for the SGS class that will be implemented on May 1, 2010 will recover 50.2% of fixed customer related costs. If all fixed customer related costs were recovered through the BMC, Centra's BMC would have to increase to approximately $28.00 for SGS customers. From a theoretical perspective a basic monthly charge in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. Such costs include service lines, meters, meter reading, billing, general customer service and distribution system costs deemed to be customer related.

<u>PUB/MH I-133</u>

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

e) Please provide the detailed rationale that MH has relied upon in making the request to reduce the BMC.

<u>ANSWER</u>:

The rationale for a reduction to the basic charge is two fold. First it eliminates the difficulty associated with establishing and monitoring income screening for low income consumers which is also intrusive to their privacy. Second, the reduction to the basic charge also accelerates the inverted rate objectives that will encourage all Manitobans to conserve energy.

For additional information please see Manitoba Hydro's response to CAC/MSOS/MH I-1(c).

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

f) **Confirm and discuss that higher volume residential customers will be cross subsidizing the customer service and fixed distribution costs of low volume residential customer.**

ANSWER:

It is true that the revenue shortfall attributed to a lower monthly Basic Charge (BMC) would be recovered through a higher tail block energy rate thereby impacting higher volume residential customers more. As discussed in parts (a) and (b) of this same question the BMC currently charged only recovers 34% of the calculated customer charge in the Cost of Service Study (PCOSS10) which is $20.38/month. Thus, from a strictly embedded cost perspective, there is apparent subsidization of fixed distribution cost of the low volume residential customer.

To the extent that there is cross-subsidization of low volume users and to the extent that low volume equates to low income, such cross-subsidization is consistent with the objectives of low income assistance programs.

PUB/MH I-133

Reference: Tab 10 page 3 of 10 basic monthly charge

g) Discuss the impact on a typical residential customer utilizing electric heat and provide supporting calculations.

ANSWER:

Higher usage electric customers will pay higher energy bills with the proposed reduction in the basic monthly charge (BMC). The primary reason is that the revenue loss in the reduction of the BMC must still be recovered in some other manner. As detailed in Tab 10 of the Application, the proposed energy rates are to increase 1.9% in the first energy block (up to 900 kW.h/month) and 7.1% in the second, or tail block, portion for all monthly consumption in excess 900 kW.h/month.

The following bill comparison from Appendix 10.5 from the Application outlines the impact. All-Electric Residential customers average approximately 2,300 kW.h/month over the year.

Bill Comparison

Residential

Forecast Customers: 445,517

kW.h	April 1, 2009 $ / Month	April 1, 2010 $ / Month	Difference in $ / Month	Percent Change
250	$22.48	$21.78	($0.70)	(3.11%)
750	$53.73	$53.63	($0.10)	(0.19%)
1 000	$69.40	$69.93	$0.53	0.76%
2 000	$132.40	$137.43	$5.03	3.80%
5 000	$321.40	$339.93	$18.53	5.77%

On February 9, 2010 Manitoba Hydro received Order 18/10 which granted interim approval of Manitoba Hydro's proposed 2.9% general rate increase for April 1, 2010. However in this Order the PUB directed that the current BMC not be reduced.

PUB/MH I-160

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Page 77)**

c) What percentage of the average contract revenue is derived from this demand charge?

ANSWER:

The demand charge provides approximately one third of the average contract revenue for existing export agreements that include a demand charge.

<u>PUB/MH I-180</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

a) **Will MH be also dealing with as yet, unresolved issues related to a possible need for higher customer charges?**

<u>ANSWER</u>:

Manitoba Hydro does not propose to increase customer charges for demand-billed customers. The only exception is the need to increase the Basic Charge for the General Service Small customer class in order to consolidate it with the Basic Charge of the Medium customer class.

Although the unit customer costs presented in PCOSS10 (filed as Appendix 11.1 of the Application) indicate under-recovery of Customer costs, these costs do not significantly impact the results presented in Tab 13.5 pertaining to Demand / Energy rebalancing.

<u>**PUB/MH I-180**</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

b) Please update the July 31, 2009 filing to reflect Winter Ratchet removal.

<u>**ANSWER**</u>**:**

Although the winter ratchet was removed as of December 1, 2009, the actual demand and energy rates charged to customers did not change, thereby not affecting the rates shown in the report. The total cost allocated to each class will not change, however the allocated cost per kV.A of billable demand will certainly change with the elimination of the winter ratchet. Table 5 in Appendix 13.7 of the Application has been revised, as provided below, to show the impact on Allocated Demand Cost if the winter ratchet kV.A had been eliminated at that time.

General Service Demand and Energy Rates vs. Allocated Cost at April 1, 2009
Revised to reflect elimination of Winter Ratchet kV.A

	Apr 1/09 Rate (Demand)	2008 Allocated Cost	Rev/Cost %	Apr 1/09 Rate (Energy)	2008 Allocated Cost	Rev/Cost %
GSS	8.34	7.40	113%	2.86	2.52	113%
GSM	8.35	8.24	101%	2.86	2.52	113%
GSL <30	7.08	9.04	78%	2.73	2.45	111%
GSL 30-100	6.06	4.99	121%	2.58	2.23	116%
GSL >100	5.40	3.51	154%	2.52	2.22	114%

PUB/MH I-180

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

d) What are the subclass revenue implications associated with the proposed rate adjustments to 2013?

ANSWER:

The Proof of Revenues filed as Appendices 10.1 and 10.2 of the Application detail the revenue implications for each subclass associated with the proposed rate increases for 2010/11 and 2011/12 only. In the absence of any further rate changes in 2013 the revenue implications would be similar to these years and change only due to forecasted consumption levels.

PUB/MH I-180

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

e) **Is it MH's intention to initiate a differential rate increase within this GRA for 2010/11 and 2011/12?**

ANSWER:

Assuming the question pertains to a differential rate increase between demand and energy charges, the answer is yes, as noted on pages 4 and 5 of Tab 10 of Manitoba Hydro's Application. All of the proposed increase in revenue for demand billed accounts will be derived from the energy portion of the rate.

Manitoba Hydro did not propose differential rate increases between customer classes.

Please also see Manitoba Hydro's response to RCM/TREE/MH I-7(a).

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

a) **Please explain what GSL <30 subclass characteristics contribute to the continued under billing of demand.**

ANSWER:

The allocated Demand unit costs for the GSL <30 kV class in the PCOSS, and shown in Table 5 of Appendix 13.7, differs from unit cost for the GSM class for the following two principal reasons.

1) Unlike the GSM class, the GSL <30 kV class does not pay a monthly basic charge, so the calculated Demand unit costs in the PCOSS includes all Customer related costs allocated to that class. Customer costs in PCOSS08 represented 69 cents of the $8.96/kVA Demand cost calculated for the GSL <30 kV class; the equivalent cost is not included in the calculated GSM Demand cost.

2) Diversity of billable demand with respect to class coincident demand is less for GSL <30 kV (13.2 units of billing demand for each unit of coincident peak demand) than for GSM (13.9 units of billable demand per unit of coincident peak demand). Unit costs are calculated in the PCOSS by dividing total Demand costs (which are allocated among classes largely on the basis of class coincident demand) by billable demand. GSM has more units of billable demand per unit of class coincident demand, and therefore has a lower cost per unit of billable demand. At least some of this additional diversity is due to the fact that GSM customers have typically been more affected by the winter ratchet. With the elimination of the winter ratchet provision effective December 1, 2009, at least some of this diversity difference will be eliminated and the cost per unit of billable demand will increase for the GSM class relative to the GSL<30.

Were the GSL<30 group to have the same ratio of billable demand to class coincident peak demand as the GSM class in the 2008 PCOSS, its billable demand would increase by 5.3% and its unit cost would decrease by 44 cents per kV.A. In summary, if GSL<30 kV diversity characteristics and costs included in the unit demand cost determination were the same as the

GSM class, its unit costs would be reduced to $7.83 per kV.A, which is very similar to that of the GSM class. See calculation below:

	Diversity factor	Demand -related costs
GSM	13.9	$7.97 per billable kV.A
GSL < 30 kV	13.2	$8.96 per billable kV.A
Eliminate Customer related costs		($0.69)
Adjust for diversity (exclude Cust costs) [(13.2-13.9)/13.2] * 8.27		($0.44)
GSL <30 kV for comparability to GSM		$7.83 per billable kV.A

There are also two principal factors affecting a comparison of unit costs of the GSL < 30 kV class with GSL 30-100.

1) The most significant factor is that the GSL <30 kV class, like GSM, is assigned costs for its usage of Distribution stations, poles and wires. The GSL 30-100kV class, and other classes who receive service at the Transmission or Subtransmission level, do not share in any of these Distribution costs. Including the portion of these costs classified as Demand adds another $3.76 to the Demand unit costs calculated for GSL <30 kV in PCOSS08; the equivalent costs are not included in the calculated GSL 30-100kV Demand cost.

2) A less important factor affecting the comparison of these two groups is that GSL 30 – 100 kV also has greater relative diversity of billing demand than GSL <30 kV (13.6 versus 13.2). Correcting for this factor would reduce the unit cost for GSL < 30 kV from $8.96 to $8.69. The difference between this diversity-adjusted unit cost, and the unit cost for GSL 30-100 kV of $4.99 is $3.70, an amount which is entirely accounted for by the Demand related Distribution costs, discussed in the previous paragraph.

The gap between the rates per kV.A for the two GSL classes is only $ 1.02 which is significantly less than the gap between the allocated unit costs. The difference between the rate gap and the embedded allocated unit cost gap results from the need to consider more than just embedded cost in designing demand rates for customers served at different voltages.

While it would be desirable to increase revenue from the GSL <30 kV class based on its allocated Revenue Requirement, a demand charge difference of $3.76 per kV.A would not be appropriate. This is because, while the overall distribution system below 30 kV shows an embedded cost differential of $3.76 per kV.A, the marginal cost of connecting a customer at below 30 kV compared to connecting at above 30 kV is considerably less, and probably closer to the current $1.02 gap between the demand charges for the two voltages. Incorporating the full embedded cost gap into the rate structure could encourage customers to seek connections at a higher voltage than is required to serve their load.

Practice in this regard at other Canadian utilities varies. SaskPower for example has a rate differential of $2.79 per kV.A between customers served at 25 kV and those served at 72 kV. However, Hydro-Quebec maintains a differential of only $0.34 per kW between customers served between 15 and 50 kV and those served at between 5 and 15 kV.

Further, Manitoba Hydro is of the view that significant changes to the demand rate for GSL < 30 kV based on these results should not be considered as the PCOSS has been prepared using a variety of methodologies over the past ten years, all of which produce differing results (as evidenced by comparing Tables 4 and 5, Appendix 13.7). Going forward, the elimination of the winter ratchet will also cause changes to RCC's, the results of which have yet to be determined. Finally, as indicated elsewhere, Manitoba Hydro is in the process of seeking a complete independent evaluation of appropriate cost allocation methodology.

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

c) Has MH given consideration to reducing or increasing the current demand charge of individual subclasses [e.g., GSL >100 and GSL < 30] given their persistent over recovery or under recovery of demand charges?

ANSWER:

Manitoba Hydro notes that the Revenue Cost Coverage for Demand and Energy components of the various subclasses are premised on the existing Cost of Service methodology which Manitoba Hydro is proposing to have extensively and independently reviewed. Should the ratios be confirmed subsequent to this review, Manitoba Hydro would consider whether changes to Demand Charges or some other mechanism, would be appropriate to address the Demand and Energy component ratios.

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

d) Please provide a listing of current and projected subclass demand charges expressed as average ¢ per kW.h.

ANSWER:

The table below provides demand revenue expressed as a price per kW.h based on the projected demand revenue divided by the forecasted kW.h's for each major demand subclass.

	Total Fcst kW.h	
Subclass	**2010/11**	**2011/12**
Small Demand	1,916,696,065	1,947,611,375
Medium	3,074,694,283	3,123,931,051
Large <30	1,574,302,879	1,590,819,485
Large 30-100	853,454,110	867,984,670
Large >100	5,354,440,000	5,635,200,000

	Demand Revenue at Proposed Rates	
Subclass	**April 2010 Rates**	**April 2011 Rates**
	2010/11	**2011/12**
Small Demand	$ 18,359,951	$ 18,656,085
Medium	$ 52,041,884	$ 50,784,729
Large <30	$ 26,215,541	$ 26,201,895
Large 30-100	$ 10,293,734	$ 10,433,860
Large >100	$ 48,806,842	$ 51,315,448

	Demand Price per kW.h	
Subclass	**2010/11**	**2011/12**
Small Demand	$ 0.00958	$ 0.00958
Medium	$ 0.01693	$ 0.01626
Large <30	$ 0.01665	$ 0.01647
Large 30-100	$ 0.01206	$ 0.01202
Large >100	$ 0.00912	$ 0.00911

PUB/MH I-182

Subject: **Tab 13: PUB Directives**
Reference: **Small and Medium Class Consolidation Report page 1 of 3**

a) Did MH consider reducing the energy rate differential between first, second, and third blocks as a conservation measure? Explain.

ANSWER:

Achieving the targeted revenue requirement for the Small Non-Demand, Small Demand and Medium Demand customer classes, while staying within bill impact limitations, requires a delicate balancing act when setting blocked energy rates for these customers. The three groups represent very diverse load characteristics, as indicated by the percentage of kW.h consumed in each block shown in the table below.

	Small Non-Demand	Small Demand	Medium Demand
First 11,000 kW.h	74.1%	6.0%	0.1%
Next 8,500 kW.h	18.7%	15.5%	0.4%
Balance of kW.h	7.2%	78.5%	99.5%

As this table indicates, increasing or decreasing the first block energy rate will have a significant impact on the revenue received from Small Non-Demand customers, but will have minimal impact on Small Demand and Medium Demand customers. Conversely, increasing the tail block rate would have little impact on Small Non-Demand customers but will greatly impact the Small Demand and Medium Demand customers.

Two other important considerations when determining the blocked energy rates for these customers is the role the Basic Charge and Demand Charge play on each subclass. The majority of customers are Small Non-Demand, hence increasing the Basic Charge, even minimally, will generate more revenue from this group of customers than the other two groups. With respect to Demand Charges, Small Non-Demand customers do not pay a Demand Charge; therefore the first block energy rate is higher to compensate for this. Medium customers, on the other hand, generate roughly 34% of their total revenue from demand charges, much higher than the 16% demand revenue received from Small Demand customers. The tail block energy rate is therefore lower to account for this.

As a price signal, the first block is more important to the Small Non-Demand class, while the last block is more important to the Small Demand and Medium classes. Manitoba Hydro already places significant emphasis on these blocks, within the constraints outlined above.

PUB/MH I-182

Subject: **Tab 13: PUB Directives**
Reference: **Small and Medium Class Consolidation Report page 1 of 3**

b) Please provide an alternative revenue neutral scenario that employs:

- **only two rate blocks.**
- **Limit the differential between first and third blocks to 2 ¢ /kW.h**

ANSWER:

Assuming the proposed Basic Charges and Demand Charges remain the same as filed in the Application, the following three scenarios (which each assume a different block amount) show the impact on each customer class of having only two rate blocks with a 2¢ differential, while still achieving the overall increase of 2.9% above current rates.

Scenario 1:

			Overall % Change
First 6,000	6.1 ¢ per kW.h	Small Non-Demand	-11.2%
Balance @	4.1 ¢ per kW.h	Small Demand	- 3.0%
		Medium	+17.8%
		Overall	+ 2.9%

Scenario 2:

			Overall % Change
First 11,000	5.9 ¢ per kW.h	Small Non-Demand	-10.0%
Balance @	3.9 ¢ per kW.h	Small Demand	- 0.7%
		Medium	+15.2%
		Overall	+ 2.9%

Scenario 3:

			Overall % Change
First 20,000	5.53 ¢ per kW.h	Small Non-Demand	- 8.4%
Balance @	3.53 ¢ per kW.h	Small Demand	+ 2.0%
		Medium	+12.3%
		Overall	+ 2.9%

PUB/MH I-220

Reference: **Tab 13, 13.4 (8) Affordable Energy Program page 30 of 46 - Basic Monthly Charge**

a) Please provide an estimate of the administrative cost for MH to implement its own screening process based on LICO x 125% eligibility criteria.

ANSWER:

Manitoba Hydro is not considering a reduction of the Basic Monthly Charge based on income. Manitoba Hydro would reduce the Basic Monthly Charge for all customers.

PUB/MH I-220

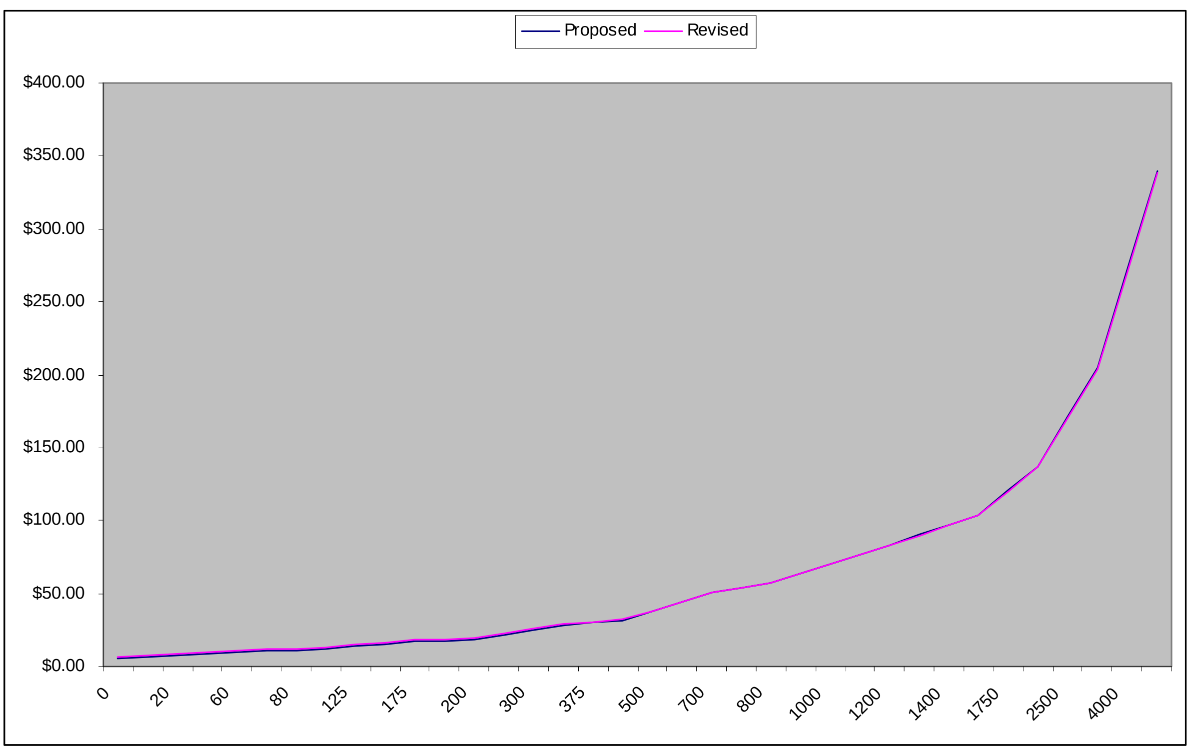
Reference: **Tab 13, 13.4 (8) Affordable Energy Program page 30 of 46 - Basic Monthly Charge**

b) **Please provide a tabular and graphical illustration of the billing impacts of MH's proposed Basic Monthly Charge reduction on the various consumption patterns of customers.**

ANSWER:

The following graph and table show the difference between the Residential rate originally proposed in the Application (Appendix 10.3) and the Residential rate revised in accordance with Board Order 18/10, for various levels of consumption. As shown in the rates below, the proposed rates reflected a lower monthly Basic Charge.

	Proposed	Revised
Basic Charge:	$5.85	$6.85
First 900 kW.h @	6.37¢	6.25¢
Balance of kW.h @	6.75¢	6.71¢



KW.h	Proposed $/Month	Revised $/Month	DIFF. $/Month
0	$5.85	$6.85	$1.00
10	$6.49	$7.48	$0.99
20	$7.12	$8.10	$0.98
40	$8.40	$9.35	$0.95
60	$9.67	$10.60	$0.93
75	$10.63	$11.54	$0.91
80	$10.95	$11.85	$0.90
100	$12.22	$13.10	$0.88
125	$13.81	$14.66	$0.85
150	$15.41	$16.23	$0.82
175	$17.00	$17.79	$0.79
185	$17.63	$18.41	$0.78
200	$18.59	$19.35	$0.76
250	$21.78	$22.48	$0.70
300	$24.96	$25.60	$0.64
350	$28.15	$28.73	$0.58
375	$29.74	$30.29	$0.55
400	$31.33	$31.85	$0.52
500	$37.70	$38.10	$0.40
600	$44.07	$44.35	$0.28
700	$50.44	$50.60	$0.16
750	$53.63	$53.73	$0.10
800	$56.81	$56.85	$0.04
900	$63.18	$63.10	($0.08)
1000	$69.93	$69.81	($0.12)
1100	$76.68	$76.52	($0.16)
1200	$83.43	$83.23	($0.20)
1300	$90.18	$89.94	($0.24)
1400	$96.93	$96.65	($0.28)
1500	$103.68	$103.36	($0.32)
1750	$120.56	$120.14	($0.42)
2000	$137.43	$136.91	($0.52)
2500	$171.18	$170.46	($0.72)
3000	$204.93	$204.01	($0.92)
4000	$272.43	$271.11	($1.32)
5000	$339.93	$338.21	($1.72)

PUB/MH II-119

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-128- Basic Monthly Charge**

a) Please add to the table in PUB/MH I-128 a residential customer count in the consumption increments shown in the table.

ANSWER:

The customer counts shown in the last column of the following table are based on 2008/09 Bill Frequency data which provides the total number of bills generated for each consumption level throughout the year. To derive at the customer counts shown, the bill counts were divided by 12, assuming that each customer receives one bill per month.

RESIDENTIAL 200 AMP & LESS

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.	Cust Count
0	$6.85	$5.85	($1.00)	-14.60%	54
10	$7.48	$6.49	($0.99)	-13.24%	2,060
20	$8.10	$7.12	($0.98)	-12.10%	1,474
40	$9.35	$8.40	($0.95)	-10.16%	2,726
60	$10.60	$9.67	($0.93)	-8.77%	2,819
75	$11.54	$10.63	($0.91)	-7.89%	3,005
80	$11.85	$10.95	($0.90)	-7.59%	57
100	$13.10	$12.22	($0.88)	-6.72%	3,517
125	$14.66	$13.81	($0.85)	-5.80%	5,787
150	$16.23	$15.41	($0.82)	-5.05%	4,303
175	$17.79	$17.00	($0.79)	-4.44%	5,208
185	$18.41	$17.63	($0.78)	-4.24%	2,335
200	$19.35	$18.59	($0.76)	-3.93%	3,989
250	$22.48	$21.78	($0.70)	-3.11%	12,596
300	$25.60	$24.96	($0.64)	-2.50%	13,410
350	$28.73	$28.15	($0.58)	-2.02%	13,891
375	$30.29	$29.74	($0.55)	-1.82%	6,387

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.	Cust Count
400	$31.85	$31.33	($0.52)	-1.63%	7,938
500	$38.10	$37.70	($0.40)	-1.05%	29,689
600	$44.35	$44.07	($0.28)	-0.63%	29,797
700	$50.60	$50.44	($0.16)	-0.32%	28,504
750	$53.73	$53.63	($0.10)	-0.19%	13,523
835	$59.04	$59.04	$0.00	0.00%	25,122
900	$63.10	$63.18	$0.08	0.13%	11,517
1000	$69.40	$69.93	$0.53	0.76%	20,912
1100	$75.70	$76.68	$0.98	1.29%	18,251
1200	$82.00	$83.43	$1.43	1.74%	15,758
1300	$88.30	$90.18	$1.88	2.13%	13,541
1400	$94.60	$96.93	$2.33	2.46%	11,610
1500	$100.90	$103.68	$2.78	2.76%	10,178
1750	$116.65	$120.56	$3.91	3.35%	23,767
2000	$132.40	$137.43	$5.03	3.80%	11,140
2500	$163.90	$171.18	$7.28	4.44%	20,676
3000	$195.40	$204.93	$9.53	4.88%	14,207
4000	$258.40	$272.43	$14.03	5.43%	18,708
5000	$321.40	$339.93	$18.53	5.77%	10,980

PUB/MH II-119

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-128- Basic Monthly Charge**

b) Please provide the number of residential customers that will experience a bill reduction and the number that will experience a bill increase based on the proposed residential rates in Appendix 10.3.

ANSWER:

One cannot answer this question with respect to number of customers; it can only be answered in regards to number of bills. Every customer receives on average 12 hydro bills per year. Based on the proposed rates in Appendix 10.3 and depending on a customer's monthly kWh usage, some bills will reflect a reduction while other bills will reflect an increase. Therefore a customer can experience both increases and decreases throughout the year.

The response to PUB/MH II-119(a) shows the number of customers (i.e. number of bills divided by 12) for each consumption level. Customers consuming less than 835 kW.h per month will, on average over the course of a year, receive a bill reduction whereas those consuming more than 835 kW.h a month will see a bill increase. Cumulatively, approximately 5,033,000 Residential bills (excluding seasonal and diesel) are issued in a given year, of which approximately 52% of them are for less than or equal to 835 kW.h.

PUB/MH II-120

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-133- Basic Monthly Charge**

a) Please provide data supporting MH's position that low-income consumers are also low volume consumers. If the type of space heating (gas or electric) influences this position, please elaborate.

ANSWER:

Manitoba Hydro indicated that those customers with lower energy use due to the size of their home would immediately benefit from the elimination/reduction of the basic monthly charge. For those customers whose energy bills which are higher and fall within the inverted tail block, they can access the Lower Income Energy Efficiency Program to reduce their consumption. For consumption, see Manitoba Hydro's response to CAC/MSOS/MH I-1(b).

PUB/MH II-120

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-133- Basic Monthly Charge**

b) Please explain why eliminating income screening is desired or necessary in the context of MH's rate design.

ANSWER:

Manitoba Hydro proposes to reduce the basic monthly charge for all consumers. As such, there would be no need to screen customers to determine eligibility based on income. This eliminates the difficulty associated with establishing and monitoring income screening for low income customers. Should a reduction in the basic monthly charge be based on predetermined criteria such an income level, an administrative process would need to be established to screen applicants. A more complicated process would also be required to monitor those customers who qualify to determine continued eligibility on an ongoing and continuous basis as a customer's incomes can change weekly or monthly and can have seasonal considerations. Other complicating factors involve consideration for a customer's asset worth and how this should impact eligibility.

PUB/MH II-148

Subject: **Tab 13 Board Directives**
Reference: **PCOSS 09-1 February 2010 Report Attachment #1**

Please provide a tabulation of demand charge revenues and PCOSS 09-1 allocated demand or non-energy costs:

	Actual Demand (MVA)	Billed Demand (MVA)	Demand Revenue ($/KVA)	Pre-Credit Allocated Non-Energy Costs ($/KVA)
GSS-D				
GSM				
GSL <30				
GSL 30-100				
GSL >100				

ANSWER:

The following includes actual and billed demand for fiscal year 2009/10, and Demand charges effective April 1, 2009. Demand costs are taken from PCOSS10 as filed in this proceeding; not PCOSS09 as cited in the reference.

	Actual Demand (MVA)	Billed Demand (MVA)	April 1, 2009 Demand Charge ($/KVA)	PCOSS10 Demand Costs Before Net Export Revenue Allocation ($/KVA)
GSS-D	5,901	2,247	8.34	8.58
GSM	7,832	7,057	8.35	9.77
GSL <30	3,619	3,727	7.08	9.58*
GSL 30-100	2,035	2,071	6.06	5.30*
GSL >100	7,962	8,237	5.40	3.67*

* Includes recovery of Customer costs.

PUB/MH II-171

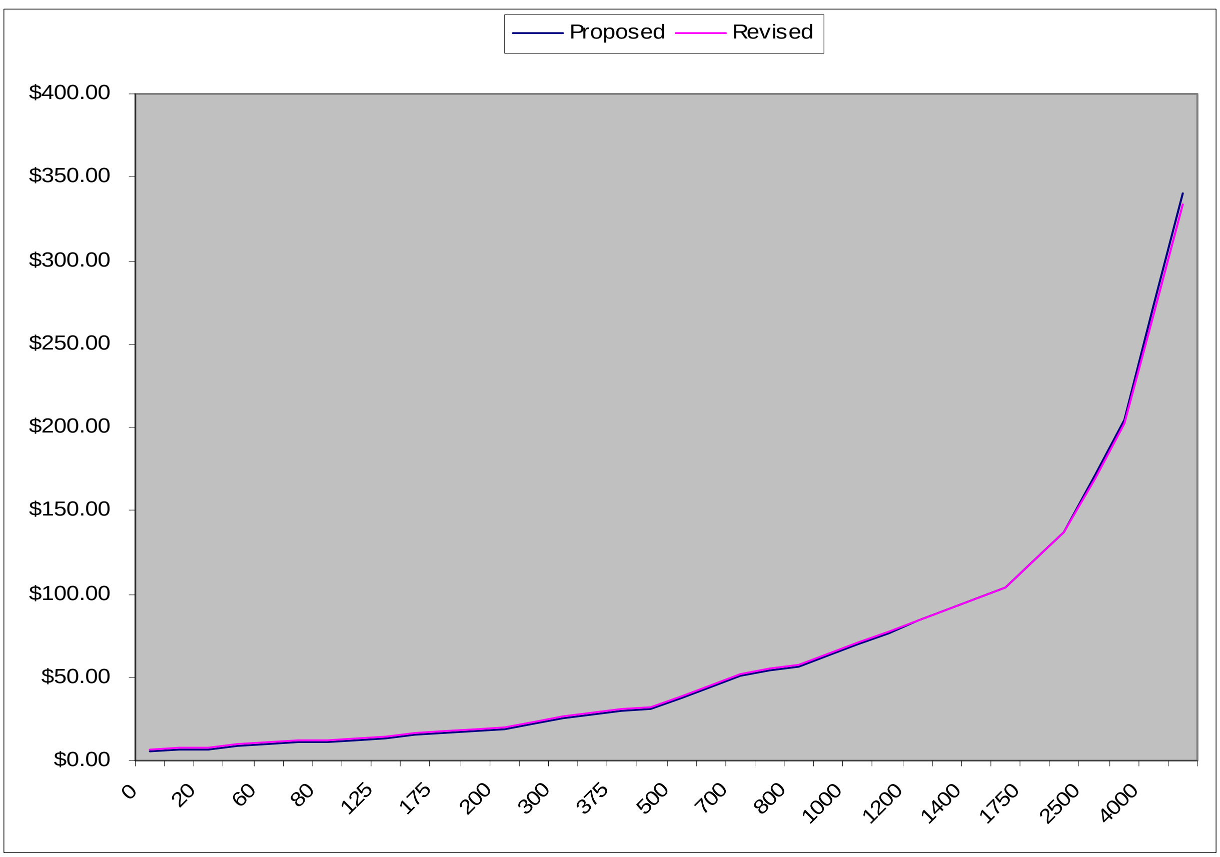
Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-220**

Please provide a comparison graph and tabular which illustrates the billing impacts of MH's proposed BMC reduction on various consumption patterns of customers with the existing rates

ANSWER:

The following graph and table illustrate the billing impacts of Manitoba Hydro's proposed rates (as filed in Appendix 10.3 of the Application) and those interim-approved as per Board Order 33/10.

	Proposed	Interim-Approved
Basic Charge:	$5.85	$6.85
First 900 kW.h @	6.37¢	6.38¢
Balance of kW.h @	6.75¢	6.57¢



KW.h	Proposed $/Month	Interim-Approved $/Month	Difference $/Month
0	$5.85	$6.85	$1.00
10	$6.49	$7.49	$1.00
20	$7.12	$8.13	$1.01
40	$8.40	$9.40	$1.00
60	$9.67	$10.68	$1.01
75	$10.63	$11.64	$1.01
80	$10.95	$11.95	$1.00
100	$12.22	$13.23	$1.01
125	$13.81	$14.83	$1.02
150	$15.41	$16.42	$1.01
175	$17.00	$18.02	$1.02
185	$17.63	$18.65	$1.02
200	$18.59	$19.61	$1.02
250	$21.78	$22.80	$1.02
300	$24.96	$25.99	$1.03
350	$28.15	$29.18	$1.03
375	$29.74	$30.78	$1.04
400	$31.33	$32.37	$1.04
500	$37.70	$38.75	$1.05
600	$44.07	$45.13	$1.06
700	$50.44	$51.51	$1.07
750	$53.63	$54.70	$1.07
800	$56.81	$57.89	$1.08
900	$63.18	$64.27	$1.09
1000	$69.93	$70.84	$0.91
1100	$76.68	$77.41	$0.73
1200	$83.43	$83.98	$0.55
1300	$90.18	$90.55	$0.37
1400	$96.93	$97.12	$0.19
1500	$103.68	$103.69	$0.01
1750	$120.56	$120.12	($0.44)
2000	$137.43	$136.54	($0.89)
2500	$171.18	$169.39	($1.79)
3000	$204.93	$202.24	($2.69)
4000	$272.43	$267.94	($4.49)
5000	$339.93	$333.64	($6.29)

PUB/MH II-181

Subject: Tab 13 Board Directives
Reference: 150/08 Directives #22/23/24/25

a) **Please confirm or revise the following table on the status on the following:**

	TOU	Inverted Rates	Rebalancing Energy Demand	Basic Customer Charge	GSS and GSM Consolidation	EIIR
Residential	N/A	Interim Rates 2010	N/A	Proposed Reduction	N/A	N/A
GSS-ND	N/A	No Action	N/A	No Action	N/A	N/A
GSS-D	Not Yet	No Action	Ongoing	No Action	Underway	N/A
GSM	Not Yet	No Action	Ongoing	No Action	Winter Ratchet Eliminated	N/A
GSL <30	Not Yet	No Action	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending
GSL 30-100	EIIR Application Pending	EIIR Application Pending	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending
GSL >100	EIIR Application Pending	EIIR Application Pending	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending

Note: SEP/CRP/LUBD and other Special Rate Programs may be integral to some of the above.

<u>ANSWER</u>:

The following changes should be made to the table shown above:

1) **GSS-ND –** this subclass is affected by the GSS and GSM Consolidation therefore should be referenced as "Underway" not "N/A" as shown.

2) **GSL<30 –** this subclass was not included in the EIIR Application and therefore should be referenced as "N/A" not "Application Pending".

PUB/MH II-181

Subject: **Tab 13 Board Directives**
Reference: **150/08 Directives #22/23/24/25**

b) **Please provide a discussion on each of the above six chart headings and on the potential for integrating the actions on various four Board Directives.**

ANSWER:

TOU (Directive 22) – Please see Manitoba Hydro response to CAC/MSOS/MH II-31(a).

Inverted Rates (Directive 23) – Manitoba Hydro has stated that in the absence of other rate revisions that future rate increases would be weighted more in the tail rate portion of the rate. This was originally proposed in the current GRA where the entire 2.9% increase was placed in the tail block. However due to concerns from CAC about this treatment for the residential class the Board requested (March 16, 2010) several different alternatives to be considered. Manitoba Hydro responded to these requests on March 18, 2010. Of the alternatives requested, the one approved by the Board for rates April 1, 2010 (Board Order 33/10) had approximately one-third of the increase in the first block and the balance in the tail block.

Energy/Demand Rebalancing (Directive 24) – Manitoba Hydro has been actively rebalancing the energy and demand components of the rate structure for the past few years. This is witnessed in that previously proposed/approved rate increases have focused the entire increase on the energy portion of the rate to expedite the rebalancing. In addition in response to the directive Manitoba Hydro has supplied various updates to the Board and to all Intervenors as to the status of this rebalancing initiative.

Basic Customer Charge (BMC) – There is no directive in the list noted in the question related to the basic monthly charge. For BMC considerations see response to PUB/MH II-182(b).

GSS & GSM Consolidation (Directive 25) – Since July 2008 Manitoba Hydro has been actively consolidating the two classes. As noted in Tab 10 of the Application, it will probably take a few more rate changes to achieve full consolidation due to the differences in the monthly Basic Charge

EIIR - Manitoba Hydro filed an application in regard to this rate February 12, 2010 that followed the intent of the Board's Order 112/09 of July 10, 2009. Since that time Manitoba Hydro has been actively consulting with customers which has resulted in some significant changes being proposed. On April 27, 2010 Manitoba Hydro representative met with MIPUG to discuss the proposal further. As a result of this meeting a cooperative framework and time line may be developed with the aim of filing a revised application to the Board in due course that represents an EIIR proposal that has been reviewed by the two parties.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

a) **Please provide a listing of the components of the fixed residential customer costs for 2010/11 and 2011/12, only a portion of which MH recovers through the residential basic monthly charge (BMC) .**

ANSWER:

Fixed residential customer costs broadly consist of Operating and Administration expenses, Depreciation and Amortization costs, Finance expense, Capital Taxes and Contribution to Reserves. Examples of the costs recoverable through the residential BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

b) Please indicate the extent to which MH's BMC recovers the fixed costs of all customer classes and how this relates to MH's rate design policy.

ANSWER:

The BMC is intended to collect a portion of those costs which are incurred to serve customers, and which do not vary with respect to customer demand or energy usage. Examples of such costs are metering, meter reading, billing and collections, and some distribution facility costs.

As shown in the table below, Manitoba Hydro currently recovers between 11% and approximately 50% of fixed customer related costs through the BMC.

Class	BMC	PCOSS10 Cust Charge	%'age
Residential	$6.85	$20.38	33.6%
GSS - Non Demand	$17.65	$33.94	52.0%
Demand	$17.65	$51.44	34.3%
GSM	$27.60	$247.59	11.1%
GSL < 30	n/a	n/a	n/a
30 - 100	n/a	n/a	n/a
> 100	n/a	n/a	n/a
A & R Lights	n/a	$8.25	n/a

Centra currently recovers between 50% and 100% of fixed customer related costs through the BMC for all customer classes. For Centra's large volume customer classes (High Volume Firm, Mainline, Interruptible, Special Contract and Power Station), 100% of fixed customer costs are recovered by the BMC. For Centra's small volume customer classes (SGS & LGS), approximately 50% of the fixed customer cost is recovered by the BMC.

The table below provides the Rate Design principles employed by both Manitoba Hydro and Centra. Rate Design Policy does not explicitly define, nor is it intended to explicitly define the appropriate level of the BMC to be recovered in rates. Utilities adopt rate design goals as a means to provide guidance in the application of ratemaking policy and the development and application of rate and billing components. In many cases, established rate design principles conflict and compromises will be effected but in aggregate support the rate design goals. For example, the desire for rate stability and public acceptability may conflict with both the desire to provide the appropriate price signals to customers and the need to recover the full revenue requirement. In other cases, some principles are reflected in the utilities rate design where practical. The ultimate rate design employed by the utility and approved by the regulator reflects the established principles, the needs of the utility, customers and other stakeholders.

Centra filed a Basic Monthly Charge report in 2005. At that time it concluded that the BMC not be changed for the SGS (residential and small commercial customers) as it strikes a reasonable compromise between various rate design considerations including customer acceptability. Since that time, the PUB has imposed several increases to Centra's BMC for both the SGS and LGS customer classes which were neither applied for by Centra nor requested by intervenors. While the current BMC for the SGS customer class is reasonably consistent with stated Rate Design Policy and the increase has not been met with significant customer resistance, Manitoba Hydro wishes to reduce and possibly eliminate both the electric and natural gas BMC. With the passage of time and the move to a greater focus on demand side management and low income programs, Manitoba Hydro views that the reduction of the BMC still conforms reasonably to stated Rate Design Policy but it also is more consistent with the Company's demand side management and low income focus. A low or no BMC allows a customer more control over usage and while any change in the BMC is revenue neutral to the Company, it benefits the low income, low users within the customer class.

Centra Gas Manitoba Inc.[1]	Manitoba Hydro[2]
Rates should be reflective of the costs incurred to provide the service (cost based). *Rates should be fair and equitable.* *Rates should be competitive.* *Rates should reflect the opportunities to serve new franchise areas.*	*Recover the full revenue requirement for domestic customers.* *Collect revenues from each class that bear a reasonable relationship to the cost allocated to serve that class using acceptable cost of service study methods.* *Establish rate structures that are reasonably reflective of the underlying costs. This would suggest that energy charges should relate to the cost of providing energy, demand charges where practical should recover a reasonable share of capacity related costs, and customer charges that recover a reasonable share of costs which are not variable with changes in usage level.* *Provide, to the extent practicable, incentives to use energy in a manner that reflects the real value of that energy.* *Provide for equitable treatment of customers both between classes and within classes of service.* *Provide for rate stability, public acceptability, freedom from controversy as to their application, and to minimize adverse changes.*

[1] Centra Gas Manitoba Inc. Cost Allocation and Rate Design Review, pre-filed evidence May 31, 1996.

[2] Manitoba Hydro, 2002 Status Update Filing, Response to Information Request PUB/MH I-82.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

c) **Please demonstrate the relationship between fixed residential customer costs, electricity consumption and household income levels.**

ANSWER:

There is no relationship of the fixed residential costs or Basic Monthly Charge (BMC) to consumption or household income levels. Any electrical residential customer of Manitoba Hydro pays the same BMC except for the few services that require a three-phase connection where the BMC is double the current BMC of $6.85/month.

In general electrical consumption does rise with income level since greater household income generally equates to larger homes and/or more electrical load.

PUB/MH II-182

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge

d) Please provide a comparison of other Canadian electric utilities' residential BMC cost recoveries.

ANSWER:

Manitoba Hydro does not survey other utilities with respect to their BMC cost recoveries, nor is this information readily available. The following however does provide a comparison of the BMC billed by other utilities:

Utility	Monthly Charge	Comments
BC Hydro	$4.02*	Basic Charge = $0.1341 per day
Enmax Corporation	$16.60*	Billing & Admin Chg $0.2373 per day + Service & Facilities Chg $0.316286 per day
EPCOR	$18.90*	Admin Chg $6.68 per month + Customer Chg $0.40758 per day
Hydro Quebec	$12.19*	Basic Charge = 40.64¢ per day
Kenora Hydro	$14.78*	Service Charge $13.53 + Smart Meter Rate Rider $1.00 + Std Supply Service Admin Chg $0.25
Manitoba Hydro	$6.85	$4.85 proposed for April 1, 2011
Maritime Electric	$24.57	
New Brunswick Power	$19.73	
Newfoundland Power	$15.57	
Nova Scotia Power	$10.83	
Saskatoon Public Works Electric System	$17.35	Service Charge $19.09 less 10% Municipal Surcharge
SaskPower	$17.35	
St. John Energy	$15.15	
Toronto Hydro	$19.18*	Service Charge $18.25 + Smart Meter Rate Rider $0.68 + Std Supply Service Admin Chg $0.25

*based on a 30 day billing period

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

e) Please demonstrate the relative Revenue to Cost Coverage & residential customer impacts of a 50%/75%/100% recovery of fixed customer costs through the BMC.

ANSWER:

Based upon the results of PCOSS10 the fixed customer costs recoverable in the residential Basic Charge are $20.38 per month. Adjusting the Residential Energy Charge to offset for the increased revenue from the changes in Basic Charge is class revenue neutral and would result in no change in the Revenue to Cost Coverage ratio. The following bill impacts result:

(It was assumed that a 0.19¢ differential would exist between the first block rate and tail block rate as does currently with the April 1, 2010 energy rate of 900 kW.h @ 6.38¢ and tail rate of 6.57¢.)

50% Proposal

BC = $10.19 1st 900 kW.h @ 6.12¢ Balance of kW.h @ 6.31¢

Monthly kWh	April 2010 Rates	50% Proposal	$ Difference	% Difference
250	$22.80	$25.49	$2.69	11.8%
750	$54.70	$56.09	$1.39	2.5%
1000	$70.84	$71.58	$0.74	1.0%
2000	$136.54	$134.68	($1.86)	-1.4%
5000	$333.64	$323.98	($9.66)	-2.9%

75% Proposal

BC = $15.29 1st 900 kW.h @ 5.72¢ Balance of kW.h @ 5.91¢

Monthly kWh	April 2010 Rates	75% Proposal	$ Difference	% Difference
250	$22.80	$29.59	$6.79	29.8%
750	$54.70	$58.19	$3.49	6.4%
1000	$70.84	$72.68	$1.84	2.6%
2000	$136.54	$131.78	($4.76)	-3.5%
5000	$333.64	$309.08	($24.56)	-7.4%

100% Proposal

BC = $20.38 1st 900 kW.h @ 5.32¢ Balance of kW.h @ 5.51¢

Monthly kWh	April 2010 Rates	100% Proposal	$ Difference	% Difference
250	$22.80	$33.68	$10.88	47.7%
750	$54.70	$60.28	$5.58	10.2%
1000	$70.84	$73.77	$2.93	4.1%
2000	$136.54	$128.87	($7.67)	-5.6%
5000	$333.64	$294.17	($39.47)	-11.8%

If the Residential Energy Charge was not adjusted, the resulting Revenue Cost Coverage ratios would be as follows:

Recovery of Fixed Customer Costs	Basic Charge	Revised RCC
50%	$10.19	98.3%
75%	$15.29	101.2%
100%	$20.38	103.9%

Increasing the Residential Basic Charge without a corresponding reduction in the Energy Charge would have a significant impact on revenues. The Residential customer sub-class (excluding seasonal and diesel) would generate additional revenues of $18 to $71 million annually dependent on the Basic Charge applied. The bill impacts, assuming no change in Energy Charge, would be as follows:

Monthly kWh	April 2010 Rates	BMC = $10.19		BMC = $15.29		BMC = $20.38	
250	$22.80	$26.14	14.7%	$31.24	37.0%	$36.33	59.3%
750	$54.70	$58.04	6.1%	$63.14	15.4%	$68.23	24.7%
1000	$70.84	$74.18	4.7%	$79.28	11.9%	$84.37	19.1%
2000	$136.54	$139.88	2.5%	$144.98	6.2%	$150.07	9.9%
5000	$333.64	$336.98	1.0%	$342.08	2.5%	$347.17	4.1%

NOTE: The figures shown as percentages represent the percentage increase from current April 2010 rates.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

f) Please provide a listing of the components of the fixed residential customer costs for natural gas operation, only a portion of which Centra recovers through the residential basic monthly charge (BMC)

ANSWER:

Fixed costs classified as customer related broadly consist of Operating and Administration expenses, Depreciation and Amortization costs, Finance expense, Capital and Other Taxes, Other Revenue and Net Income.

Examples of Operating and Administration costs classified as customer related include Centra's billing system, Contact Centre costs, Meter Reading costs, Inspection and maintenance of service lines and meter/regulator sets, Customer marketing costs including customer safety programs (call before you dig) and Burner Tip.

Depreciation and Amortization Expense, Municipal and Capital Taxes, Finance Expense, and Net Income associated with service lines, meters and regulators, common assets, DSM, and Furnace Replacement program costs and a portion of the Distribution system is also classified as customer related.

<u>RCM/TREE/MH I-7</u>

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

a) Please provide the "5-year transition plan" to rebalance demand and energy charges that Hydro has prepared or submitted in response to PUB Order 116/08, Directive 24 (referred to on page 1).

<u>ANSWER</u>:

Manitoba Hydro has not prepared a "5-year transition plan". The following tables do however provide the Demand / Energy Rebalancing progress made since 2003 to 2011, assuming the rates proposed in Manitoba Hydro's Rate Application are approved as filed.

ENERGY:

General Service Demand / Energy Rate Rebalancing: Progress Since 2003					
Rate ¢ per kW.h Energy					
	Small	**Medium**	**Large <30**	**Large 30-100**	**Large >100**
Rate as of March 2003	2.12¢	2.12¢	2.01¢	1.98¢	1.98¢
Rate Mar 2003 if rebalanced	2.54¢	2.54¢	2.50¢	2.30¢	2.28¢
Class cumulative rate increase to April 1/11	25.11%	24.72%	25.62%	23.23%	23.53%
March 2003 rate adjusted for increases	2.65¢	2.64¢	2.52¢	2.43¢	2.44¢
Rebalanced Mar 2003 rate adj for increases	3.18¢	3.17¢	3.15¢	2.84¢	2.82¢
Proposed rate April 2011	3.20¢	3.20¢	3.01¢	2.81¢	2.73¢
Rebalanced progress	104%	106%	78%	94%	77%

DEMAND:

General Service Demand / Energy Rate Rebalancing: Progress Since 2003					
Rate $ per kV.A Demand					
	Small	**Medium**	**Large <30**	**Large 30-100**	**Large >100**
Rate as of March 2003	$8.41	$8.32	$7.09	$6.36	$5.75
Rate Mar 2003 if rebalanced	$6.98	$6.79	$5.07	$4.53	$3.58
Class cumulative rate increase to April 1/11	25.11%	24.72%	25.62%	23.23%	23.53%
March 2003 rate adjusted for increases	$10.52	$10.38	$8.91	$7.84	$7.10
Rebalanced March 2003 rate adj for increases	$8.73	$8.47	$6.37	$5.58	$4.42
Proposed rate April 2011	$8.34	$8.34	$7.08	$6.06	$5.40
Rebalanced Progress	122%	107%	72%	79%	64%

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

b) Please specify Hydro's current demand-energy rebalancing targets by rate.

ANSWER:

If the intent on rebalancing demand and energy is to continue moving these charges toward their embedded costs as depicted in the cost of service study (and as premised in Order 116/08 Directive 24), then the energy rate for the Large >30 kV classes will have to continue to increase at a faster pace than their demand charge, as indicated in the table below.

Assuming the proposed rates filed in the Application are approved, then Manitoba Hydro can begin to apply increases to both demand and energy charges for the Small, Medium and Large <30 kV rate classes.

These results are contingent on Manitoba Hydro's Cost of Service for 2010, but as indicated on page 2 of Tab 11 of the Application, these results may change pending a review of COSS methodologies.

	Prop. Apr/11 Rate (Demand)	**PCOSS10 Allocated Cost**	**Rev / Cost %**		**Prop. Apr/11 Rate (Energy)**	**PCOSS10 Allocated Cost**	**Rev / Cost %**
GSS	8.34	7.74	108%		3.20	2.95	108%
GSM	8.34	8.81	95%		3.20	2.95	108%
GSL <30	7.08	8.64	82%		3.01	2.89	104%
GSL 30-100	6.06	4.78	127%		2.81	2.58	109%
GSL >100	5.40	3.31	163%		2.73	2.56	107%

<u>RCM/TREE/MH I-7</u>

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

d) Please explain the rationale that Hydro "accepts in principle" for collecting some demand-related costs "in a peak period energy charge … where infrastructure for Time-of-Use billing is in place" (discussed on page 5).

<u>ANSWER</u>:

The statement means that Manitoba Hydro accepts in principle that some demand related costs could be collected in a peak period energy charge but does not have a specific proposal at this time.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

e) Please provide Hydro's implementation plans for collecting some demand-related costs in a peak period energy charge where infrastructure for Time-of-Use billing is now in place, that is, in the General Service Large >100 kV and General Service 30-100 kV classes (discussed on page 5).

i. If Hydro has no implementation plans for this rate design, explain why.

ANSWER:

Manitoba Hydro does not have implementation plans for this rate as it has yet to determine and finalize a specific rate design.

The Energy Intensive Rate Application filed with the Public Utilities Board on February 12, 2010 includes a time-of-use component for which on-peak energy use in excess of a customer's on-peak baseline will be billed at an energy rate related to marginal cost.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

f) Please provide Hydro's current estimates of marginal T&D costs.

ANSWER:

Manitoba Hydro has not updated its T&D marginal costs since 2004. These marginal costs are provided in the report "Marginal Transmission and Distribution Cost Estimates. SPD 04/05" Manitoba Hydro, September 23, 2004. This report is provided as Appendix 49.

In order to obtain current 2009 estimates, the marginal T&D costs are escalated from the above 2004 report. The current escalated T&D marginal costs in 2009 dollars are as follows:

- Transmission: 73.87 $/kW/yr
- Distribution: 44.78 $/kW/yr

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

g) Please provide the Company's most recent marginal T&D cost study, including all workpapers and spreadsheets (with formulas intact).

ANSWER:

Please see Manitoba Hydro's response to RCM/TREE/MH I-7(f) which indicates that the report "Marginal Transmission and Distribution Cost Estimates. SPD 04/05" Manitoba Hydro, September 23, 2004 is the most recent marginal T&D cost study.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

h) Please provide the source of Hydro’s current estimates of marginal T&D costs, including studies, workpapers, and Excel spreadsheets (with formulas intact).

ANSWER:

Please see Manitoba Hydro’s response to RCM/TREE/MH I-7(f) which indicates that the source of Hydro’s current estimate of marginal T&D costs is the report “Marginal Transmission and Distribution Cost Estimates. SPD 04/05” Manitoba Hydro, September 23, 2004.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

j) Please provide the Company's distribution planning guidelines.

ANSWER:

The following standards and guidelines are applicable to Manitoba Hydro Distribution Planning

Safety

Manitoba Hydro is required to observe the requirements of the CSA Standard C22.3 No. 1 - "Overhead Systems", CSA Standard C22.3 No. 7 - "Underground Systems", CSA Standard C22.3 No. 3 - "Electrical Coordination, CSA Standard C22.3 No. 5.1 - "Recommended Practices for Electrical Protection - Electric Contact Between Overhead Supply and Communication Lines", and CSA Standard C22.3 No. 9 - "Interconnection of Distributed Resources and Electricity Supply Systems".

Distribution Voltage Criteria

Manitoba Hydro Voltage levels and criteria are specified in the CSA Standard CAN-3-C235-83 - "Preferred Voltage Levels for AC Systems 0 to 50,000 Volts.

Distribution Transformer Loading Guidelines

Manitoba Hydro's maximum distribution loading limits are based on the IEEE C57.91 - 1995 Guide for Loading Mineral-Oil-Immersed Transformers utilizing a 90% preload and appropriate average ambient temperatures.

Power Transformer Loading Guidelines

Manitoba Hydro's maximum station power transformer loading limits are based on the IEEE C57.91-1995 Guide for Loading Mineral-Oil-Immersed Transformers. Based on these guidelines, two loading levels are defined: normal and emergency. "Normal" loading limits are applied to transformers under normal load conditions. "Emergency" loading limits are applied to transformers under first contingency, the failure of a bank, where the remaining banks can be loaded to emergency limits. Some loss of life is assumed under emergencies and this is why these levels are higher.

Station Loading & Reliability

Stations are divided into two basic categories: those having FIRM station capacity and those having NON-FIRM station capacity.

FIRM STATION CAPACITY is that load which a station has the ability to supply indefinitely, after the loss of its largest transformer, with no more than a short customer interruption to facilitate switching within the station. Switching outside the station is not included within the definition because of the length of time such switching may take.

Those stations having NON-FIRM capacity will experience an extended outage up to 20 hours in length, in order to transport and connect the mobile transformer, or if a tie feeder is available, they may experience an outage of perhaps 2 hours.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

k) Please provide the load diversity assumptions used by Hydro in designing its distribution additions.

ANSWER:

For commercial and industrial customers, Manitoba Hydro accepts the load provided by the consultant. The load is then adjusted further based on Manitoba Hydro's experience with similar customers.

Residential customers are estimated to have a diversified electrical load of 3.5 kVA for a gas-heated residence and 10 kVA for an electrically heated residence.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

l) Please provide the most recent study of load diversity on Hydro's:

- **i. Subtransmission lines**
- **ii. Substations**
- **iii. Primary distribution lines**
- **iv. Secondary lines**
- **v. Line transformers**

ANSWER:

Manitoba Hydro does not have a document that has been approved for external release.

<u>RCM/TREE/MH I-7</u>

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

m) Please provide Hydro's current estimates of marginal generation plant and O&M costs.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-66(c) which provides a marginal cost of the generation component as $6.47/kW.h in 2009/10 for the residential class of customers.

<u>RCM/TREE/MH I-7</u>

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

n) Please provide the Company's most recent marginal generation plant and O&M cost study, including all workpapers and spreadsheets (with formulas intact).

<u>ANSWER</u>:

The current methodology that Manitoba Hydro uses to determine the generation component of marginal cost is based solely on the production costing benefits to the Manitoba Hydro system, with export prices being the primary factor in influencing marginal benefit. The marginal cost study is not being provided since it contains information on forecast prices of specific electricity export products. The determination of marginal cost is a complex exercise and general description of the process is provided below.

The generation-related marginal benefit is derived by an analysis of production costing for a system with or without a small quantity of capacity and energy. A complex computer model (SPLASH) is utilized to simulate operation of the system of reservoir and generating facilities to meet firm load requirements while minimizing operating costs and maximizing export revenues. A range of 94 possible flow conditions is utilized to determine the value of the small increment of energy and capacity. This value is dependent on the mix of thermal and import energy and the quantity of export energy associated with each of the flow conditions. In low flow conditions, the marginal benefit is derived from the displacement of high-cost thermal and import energy, while in median to high flow conditions the benefit is derived primarily from new export sales. Benefits may be very small or even nonexistent in extremely high flows when tie-lines may be saturated and reservoirs filled to capacity.

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

o) Please specify the percentage of feeders that peak in the summer and the percentage that peak in the winter.

ANSWER:

Area	Total Feeders	Summer Peaking	%	Winter Peaking	%	Equal Summer & Winter	%
Rural - West	442	5	1	437	99		
Winnipeg - Suburban	469	122	26	321	68	26	6
Winnipeg - Central	300	30	10	270	90		
Rural - East & North	427	8	2	419	98		
TOTAL	1,638	165	10	1,447	88	26	2

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

p) For each substation owned by MH, please provide in a single table:

- **i. the summer and winter peak load (MW or MVA) on each substation;**
- **ii. the date and time of the summer and winter peaks on each substation;**
- **iii. the summer and winter effective capability of each substation**

ANSWER:

	Winnipeg Central Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Date of Measurement	Time
1	Alfred (12), 4kV	Winter	12,900	9,720	2009-01-15	17:00
	Alfred (12), 4kV	Summer	12,900	5,370	2009-07-04	17:00
2	Amy (6), 4kV	Winter	18,700	10,680	2009-01-14	9:22
	Amy (6), 4kV	Summer	18,700	8,140	2009-07-22	14:18
3	Arlington (4), 4kV	Winter	30,400	19,330	2006-12-06	18:03
	Arlington (4), 4kV	Summer	34,600	12,890	2009-07-06	15:47
4	Boyd (10), 4kV	Winter	14,700	10,280	2009-01-14	18:38
	Boyd (10), 4kV	Summer	17,300	7,870	2009-07-06	12:57
5	Cambridge (15), 4kV	Winter	20,200	10,940	2009-01-04	17:00
	Cambridge (15), 4kV	Summer	20,000	7,080	2009-07-09	17:00
6	Charles (11), 4kV	Winter	14,700	14,020	2009-01-04	17:00
	Charles (11), 4kV	Summer	17,300	8,900	2009-07-09	17:00
7	Church (25), 12kV	Winter	36,000	17,030	2009-01-27	10:59
	Church (25), 12kV	Summer	47,700	16,340	2009-07-14	12:43
8	Edmonton (21), 12kV	Winter	57,500	39,130	2009-01-14	12:13
	Edmonton (21), 12kV	Summer	69,100	41,020	2009-07-22	15:05
9	Edmonton (21), 4kV	Winter	25,300	14,970	2009-01-14	11:46
	Edmonton (21), 4kV	Summer	28,800	12,630	2009-07-16	17:56
10	Empress (20), 4kV	Winter	16,500	8,440	2009-01-14	11:00

	Winnipeg Central Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Date of Measurement	Time
	Empress (20), 4kV	Summer	20,000	7,420	2009-07-09	17:00
11	Fife (24), 4kV	Winter	30,400	16,530	2009-01-14	11:30
	Fife (24), 4kV	Summer	36,600	16,050	2009-07-06	12:50
12	Jessie (22), 12kV	Winter	36,000	17,430	2009-01-14	10:19
	Jessie (22), 12kV	Summer	47,400	14,010	2009-07-23	18:17
13	Jessie (22), 4kV	Winter	37,500	26,960	2009-01-14	18:37
	Jessie (22), 4kV	Summer	37,500	17,090	2009-07-23	17:56
14	Keewatin (18), 4kV	Winter	20,000	9,110	2009-01-15	11:00
	Keewatin (18), 4kV	Summer	20,000	8,990	2009-07-06	13:46
15	King (1), 12kV	Winter	53,300	34,170	2009-01-15	12:17
	King (1), 12kV	Summer	53,300	32,820	2009-07-22	14:38
16	King (1), 4kV	Winter	30,000	19,010	2009-01-15	11:26
	King (1), 4kV	Summer	30,000	13,820	2009-07-22	13:58
17	Lindsay (7), 4kV	Winter	14,700	9,430	2009-01-04	18:10
	Lindsay (7), 4kV	Summer	17,300	6,100	2009-07-26	21:46
18	Logan (23) A, 4kV	Winter	24,800	18,330	2009-01-14	17:54
	Logan (23) A, 4kV	Summer	30,000	13,090	2009-07-06	15:49
19	Logan (23) B, 4kV	Winter	26,500	18,020	2009-01-14	11:18
	Logan (23) B, 4kV	Summer	30,000	14,660	2009-07-02	10:42
20	Martin (17), 4kV	Winter	14,680	12,510	2009-01-15	17:00
	Martin (17), 4kV	Summer	17,300	0	2009-07-01	0:00
21	Rover (3), 4kV	Winter	30,200	15,970	2009-01-05	17:00
	Rover (3), 4kV	Summer	32,400	12,100	2009-07-07	17:00
22	Scotland (5), 4kV	Winter	27,100	17,680	2009-01-15	17:00
	Scotland (5), 4kV	Summer	27,100	12,380	2009-07-09	17:00
23	Sherbrook (14), 12kV	Winter	48,700	24,990	2009-01-15	12:00
	Sherbrook (14), 12kV	Summer	64,400	25,900	2009-07-23	17:27
24	Sherbrook (14), 4kV	Winter	21,600	13,610	2009-01-14	17:47
	Sherbrook (14), 4kV	Summer	21,600	8,990	2009-07-23	18:51
25	St. Matthews (8), 12kV	Winter	44,000	24,000	2009-01-07	18:10
	St. Matthews (8), 12kV	Summer	51,800	23,390	2009-07-07	15:30
26	St. Matthews (8), 4kV	Winter	16,500	8,110	2009-01-14	18:09
	St. Matthews (8), 4kV	Summer	19,500	7,210	2009-07-22	16:23

	Winnipeg Central Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Date of Measurement	Time
27	Strathcona (9), 4kV	Winter	14,700	7,440	2009-01-14	11:05
	Strathcona (9), 4kV	Summer	17,300	7,270	2009-07-22	15:48
28	Taylor (16), 12kV	Winter	36,000	10,360	2009-01-14	18:41
	Taylor (16), 12kV	Summer	47,700	6,690	2009-07-22	14:39
29	Taylor (16), 4kV	Winter	14,700	8,950	2009-01-04	17:43
	Taylor (16), 4kV	Summer	17,300	5,930	2009-07-20	17:50
30	York (2), 12kV	Winter	54,000	27,320	2009-01-14	12:20
	York (2), 12kV	Summer	71,500	29,590	2009-07-22	14:14

	Winnipeg Suburban Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
31	ATWOOD	Winter	80,400	24,553	2008/2009
	ATWOOD	Summer	60,800	21,929	2009
32	AUGIER	Winter	78,750	20,541	2008/2009
	AUGIER	Summer	61,876	23,774	2009
33	BAYLOR	Winter	26,990	9,532	2008/2009
	BAYLOR	Summer	20,070	6,380	2009
34	BEAVERHILL	Winter	22,340	4,653	2008/ 2009
	BEAVERHILL	Summer	14,280	3,549	2009
35	BERRY	Winter	13,150	7,343	2008/2009
	BERRY	Summer	18,980	5,820	2009
36	CAVALIER	Winter	31,710	15,687	2008/ 2009
	CAVALIER	Summer	28,310	11,358	2009
37	CHESTERFIELD	Winter	22,500	7,456	2008/2009
	CHESTERFIELD	Summer	22,500	4,709	2009
38	CHEVRIER	Winter	69,440	21,824	2008/2009
	CHEVRIER	Summer	52,920	10,124	2009
39	COURT	Winter	171,100	32,008	2008/2009
	COURT	Summer	133,100	29,059	2009
40	CRESTVIEW	Winter	25,760	10,170	2008/2009
	CRESTVIEW	Summer	21,600	3,808	2009
41	DAKOTA	Winter	123,400	53,997	2008/ 2009

	Winnipeg Suburban Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
	DAKOTA	Summer	78,840	48,186	2009
42	DAWSON RD - 4 KV	Winter	28,820	6,739	2008/ 2009
	DAWSON RD - 4 KV	Summer	28,820	4,924	2009
43	DAWSON RD - 24 KV	Winter	32,400	20,624	2008/2009
44	DAY	Winter	78,700	37,264	2008/2009
	DAY	Summer	61,300	30,320	2009
45	DE BOURMONT	Winter	12,900	4,278	2008/ 2009
	DE BOURMONT	Summer	11,000	3,636	2009
46	DES MEURONS	Winter	36,000	15,994	2008/2009
	DES MEURONS	Summer	36,000	9,572	2009
47	DUGALD	Winter	12,960	12,868	2008/2009
	DUGALD	Summer	11,360	3,938	2009
48	DUNRAVEN	Winter	17,300	9,507	2008/ 2009
	DUNRAVEN	Summer	17,300	6,117	2009
49	EMERSON	Winter	31,190	13,458	2009/2010
	EMERSON	Summer	23,150	10,867	2009
50	FERMOR	Winter	13,340	6,092	2008/ 2009
	FERMOR	Summer	13,340	2,130	2009
51	FERNBANK	Winter	10,000	8,797	2008/2009
	FERNBANK	Summer	10,000	8,444	2009
52	FRENCH	Winter	27,830	7,230	2008/2009
	FRENCH	Summer	26,000	4,929	2009
53	FROBISHER	Winter	44,100	14,752	2008/2009
	FROBISHER	Summer	32,700	30,591	2009
54	GOULET	Winter	34,600	8,794	2008/ 2009
	GOULET	Summer	26,300	7,077	2009
55	GRANDE POINTE	Winter	12,960	9,742	2008/2009
	GRANDE POINTE	Summer	12,160	5,102	2009
56	HARROW	Winter	30,000	23,902	2008/2009
	HARROW	Summer	30,000	24,465	2009
57	HEADINGLEY	Winter	16,000	4,392	2008/2009
	HEADINGLEY	Summer	12,550	2,196	2009
58	INKSTER	Winter	75,600	33,410	2008/2009

	Winnipeg Suburban Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
	INKSTER	Summer	58,800	31,798	2009
59	KING EDWARD	Winter	22,340	6,007	2008/2009
	KING EDWARD	Summer	14,280	6,341	2009
60	KINGSBURY	Winter	16,400	5,804	2008/2009
	KINGSBURY	Summer	15,640	5,589	2009
61	KIRKFIELD	Winter	40,000	40,994	2008/2009
	KIRKFIELD	Summer	40,000	41,180	2009
62	LAXDAL	Winter	17,710	5,279	2008/2009
	LAXDAL	Summer	14,300	3,503	2009
63	LORETTE	Winter	12,940	7,839	2008/2009
	LORETTE	Summer	11,000	4,128	2009
64	MARKHAM	Winter	22,340	9,257	2008/2009
	MARKHAM	Summer	14,280	5,066	2009
65	MCPHILLIPS	Winter	71,600	39,473	2007/2008
	MCPHILLIPS	Summer	65,700	33,387	2009
66	MIDDLECHURCH	Winter	10,000	5,343	2008/2009
	MIDDLECHURCH	Summer	10,000	2,474	2009
67	MOHAWK	Winter	160,000	94,960	2008/2009
	MOHAWK	Summer	160,000	89,609	2009
68	NESS	Winter	15,840	4,478	2008/2009
	NESS	Summer	13,340	5,672	2009
69	Norcraft	Winter	5,000	1,369	2008/2009
	Norcraft	Summer	5,000	1,972	2009
70	NOTRE DAME	Winter	25,950	10,345	2008/2009
	NOTRE DAME	Summer	21,420	8,863	2009
71	OAK BLUFF	Winter	10,000	9,076	2008/2009
	OAK BLUFF	Summer	10,000	3,770	2009
72	OAKBANK	Winter	24,300	21,253	2008/2009
	OAKBANK	Summer	21,300	10,627	2009
73	OLIVE	Winter	16,940	7,681	2008/2009
	OLIVE	Summer	15,610	5,331	2009
74	PEGUIS	Winter	32,180	15,982	2008/2009
	PEGUIS	Summer	24,300	13,132	2009

	Winnipeg Suburban Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
75	PEMBINA	Winter	5,760	58	2008/2009
	PEMBINA	Summer	5,280	1,576	2009
76	PERIMETER SOUTH	Winter	23,760	18,899	2008/2009
	PERIMETER SOUTH	Summer	23,600	11,699	2009
77	PLESSIS RD	Winter	275,600	68,194	2008/2009
	PLESSIS RD	Summer	235,200	87,166	2009
78	RANNOCK	Winter	30,500	5,992	2008/2009
	RANNOCK	Summer	23,600	4,125	2009
79	RIDGEWAY	Winter	37,750	25,623	2009/2010
	RIDGEWAY	Summer	25,820	11,946	2009
80	ROSE	Winter	20,180	10,270	2008/ 2009
	ROSE	Summer	14,280	7,786	2009
81	SANFORD	Winter	16,080	7,737	2008/2009
	SANFORD	Summer	12,160	2,855	2009
82	SEMPLE	Winter	22,760	16,262	2008/2009
	SEMPLE	Summer	22,760	9,868	2009
83	SHAFTSBURY	Winter	21,620	5,654	2008/ 2009
	SHAFTSBURY	Summer	14,280	2,477	2009
84	SIMPSON	Winter	26,300	13,815	2009/2010
	SIMPSON	Summer	24,300	13,004	2009
85	SOUTHWOOD	Winter	28,000	14,271	2008/2009
	SOUTHWOOD	Summer	28,000	24,205	2009
86	SPRINGFIELD - 12 KV	Winter	80,440	40,790	2009/2010
	SPRINGFIELD - 12 KV	Summer	60,760	45,395	2009
87	ST JAMES - 4 KV	Winter	18,000	4,493	2008/2009
	ST JAMES - 4 KV	Summer	18,000	8,497	2009
88	ST JAMES - 24 KV	Winter	208,000	54,306	2008/2009
	ST JAMES - 24 KV	Summer	208,000	67,321	2009
89	ST NORBERT	Winter	10,000	3,367	2008/2009
	ST NORBERT	Summer	10,000	2,505	2009
90	ST VITAL TERMINAL	Winter	121,300	38,642	2008/2009
	ST VITAL TERMINAL	Summer	91,600	59,589	2009
91	STORIE	Winter	62,640	10,049	2008/2009

	Winnipeg Suburban Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
	STORIE	Summer	40,180	13,834	2009
92	STURGEON	Winter	22,340	9,382	2008/2009
	STURGEON	Summer	14,280	7,083	2009
93	TRANSCONA SOUTH	Winter	11,700	7,027	2008/2009
	TRANSCONA SOUTH	Summer	8,330	3,404	2009
94	TRANSCONA-C.P.R.	Winter	5,000	3,008	2008/2009
	TRANSCONA-C.P.R.	Summer	5,000	2,549	2009
95	UNIVERSITY	Winter	21,620	15,537	2008/2009
	UNIVERSITY	Summer	21,620	17,888	2009
96	WATT ST.	Winter	25,950	11,178	2009/2010
	WATT ST.	Summer	25,950	13,623	2009
97	WILKES	Winter	100,000	76,631	2008/2009
	WILKES	Summer	100,000	77,293	2009
98	WINDSOR PARK	Winter	19,000	6,230	2008/2009
	WINDSOR PARK	Summer	13,800	8,860	2009

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
99	ALEXANDER	Winter	4,871	2,515	2009/2010
100	AMARANTH	Winter	17,438	15,514	2008/ 2009
101	ANGUSVILLE	Winter	2,340	1,098	2009/2010
102	AUSTIN	Winter	10,060	7,905	2008/ 2009
103	BALDUR	Winter	16,016	6,280	2008/ 2009
104	BENITO	Winter	7,550	5,021	2008/ 2009
105	BEULAH	Winter	7,550	2,511	2008/2009
106	BINSCARTH	Winter	4,680	2,840	2008/ 2009
107	BIRCH RIVER	Winter	8,250	3,603	2008/ 2009
108	BIRTLE QUEEN ST	Winter	15,100	7,554	2008/2009
109	BOISSEVAIN	Winter	23,193	13,012	2008/ 2009
110	BRANDON 65TH STREET EAST	Summer	36,303	19,992	2008
	BRANDON 65TH	Winter	42,279	17,940	2008/ 2009

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
	STREET EAST				
111	BRANDON BLACK ST	Winter	8,600	2,985	2008/ 2009
112	BRANDON CROCUS PLAINS	Winter	43,400	20,991	2008/ 2009
113	BRANDON ELVISS	Winter	3,000	1,360	2008/ 2009
114	BRANDON FORTIER	Summer	34,594	18,659	2008
	BRANDON FORTIER	Winter	43,594	27,816	2008/ 2009
115	BRANDON GENERAL HOSPITAL	Winter	5,786	1,533	2006/ 2007
116	BRANDON HIGHLAND PARK	Summer	17,066	10,511	2008
	BRANDON HIGHLAND PARK	Winter	21,999	20,714	2008/ 2009
117	BRANDON LORNE AVE	Winter	26,300	29,773	2008/ 2009
118	BRANDON LOUISE	Summer	5,850	2,310	2009
	BRANDON LOUISE	Winter	7,740	5,316	2007/ 2008
119	BRANDON MCTAVISH AVE	Winter	8,250	6,300	2008/ 2009
120	BRANDON PATRICIA AVE	Winter	26,500	10,213	2008/ 2009
121	BRANDON SERVICE CENTER	Winter	3,000	721	2004/ 2005
122	BRANDON UNIVERSITY 267684	Winter	2000	1,663	2008/ 2009
123	BRANDON VICTORIA AVE	Winter	6,880	3,396	2008/ 2009
124	BROOMHILL	Winter	3,120	1,508	2008/2009
125	CAMPERVILLE	Winter	15,160	5,645	2008/ 2009
126	CARBERRY NORTH	Winter	41,250	26,775	2008/ 2009
127	CARROLL	Winter	4,300	2,989	2008/2009
128	CARTWRIGHT	Winter	10,000	6,444	2008/ 2009
129	CRANBERRY	Winter	43,400	6,036	2009/2010

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
	PORTAGE				
130	CROMER NORTH	Winter	10,000	9,764	2008/ 2009
131	CROSSING BAY	Winter	4,300	235	2009/2010
132	CYPRESS RIVER	Winter	5,160	4,464	2008/ 2009
133	DAUPHIN 2ND ST NW	Winter	10,000	9,552	2008/ 2009
134	DAUPHIN MOUNTAIN AVE	Winter	26,500	11,044	2008/ 2009
135	DAUPHIN VERMILION	Winter	10,000	10,348	2008/ 2009
136	DELORAINE	Winter	26,500	9,239	2008/2009
137	DOUGLAS	Winter	6,600	4,532	2008/ 2009
138	ELKHORN CUSHING AVE	Winter	8,250	5,826	2008/ 2009
139	ERICKSON	Winter	10,000	6,585	2008/ 2009
140	ETHELBERT	Winter	4,680	3,082	2008/ 2009
141	FLIN FLON ROSS LAKE	Winter	82,500	36,625	2009/2010
142	FORREST	Winter	10,000	5,372	2008/ 2009
143	FOXWARREN	Winter	7,550	2,423	2008/ 2009
144	GILBERT PLAINS	Winter	11,700	5,929	2008/ 2009
145	GLADSTONE	Winter	10,000	7,934	2007/ 2008
146	GLENBORO NORTH	Winter	20,320	6,496	2007/ 2008
147	GLENELLA	Winter	7,550	3,016	2007/ 2008
148	GRAND RAPIDS	Summer	34,440	3,549	2008
	GRAND RAPIDS	Winter	43,400	9,625	2009/2010
149	GRANDVIEW	Winter	11,700	5,914	2008/ 2009
150	GUY HILL	Winter	8,250	3,767	2009/2010
151	HAMIOTA	Winter	16,500	8,476	2008/ 2009
152	HARTNEY	Winter	20,131	7,110	2008/ 2009
153	HOLLAND	Winter	6,600	4,141	2005/2006
154	HOLLAND DSC	Winter	7,350	5,840	2009/2010
155	INGLIS	Winter	7,550	4,567	2008/2009

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
156	KILLARNEY	Winter	33,193	19,011	2007/ 2008
157	LANGRUTH	Winter	4,680	2,326	2007/ 2008
158	LENA DSC	Winter	7,350	2,372	2008/2009
159	MACGREGOR	Winter	20,131	8,725	2007/ 2008
160	MAFEKING	Winter	8,600	1,738	2008/ 2009
161	MANSON	Winter	8,600	2,232	2008/ 2009
162	MCCREARY	Winter	15,100	7,261	2008/ 2009
163	MELITA	Winter	26,500	10,177	2008/ 2009
164	MINIOTA	Winter	4,873	3,235	2008/2009
165	MINITONAS	Winter	7,550	4,728	2008/2009
166	MINNEDOSA SOUTH	Winter	21,999	14,624	2007/ 2008
167	MINTO	Winter	4,873	2,979	2008/ 2009
168	MOOSE LAKE	Winter	8,600	3,748	2009/2010
169	NEELIN	Winter	7,020	3,316	2009/2010
170	NEEPAWA	Summer	22,000	10,544	2008
171	NEEPAWA	Winter	26,500	18,906	2008/ 2009
172	NEEPAWA NORTH	Winter	9,890	4,487	2008/ 2009
173	NINETTE	Winter	12,230	3,982	2008/2009
174	OAK LAKE	Winter	10,000	6,364	2008/ 2009
175	OAKBURN	Winter	5,000	3,150	2007/2008
176	OCHRE RIVER	Winter	5,663	4,311	2006/ 2007
177	ONANOLE	Summer	11,000	5,548	2009
	ONANOLE	Winter	15,100	6,302	2008/ 2009
178	PELICAN RAPIDS DSC	Winter	7150	3,011	2006/2007
179	PIERSON	Summer	5,500	2,950	2008
	PIERSON	Winter	8,043	6,317	2009/2010
180	PILOT MOUND	Winter	27,438	13,556	2008/ 2009
181	PINE RIVER	Winter	7,550	2,496	2008/ 2009
182	PIPESTONE	Winter	7,550	3,572	2009/2010
183	PLUMAS	Winter	4,680	3,543	2006/ 2007
184	PROSPECTORS CORNER DSC	Winter	7150	1,654	2009/2010

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
185	Pukatawagan	Winter	8,250	5,812	2008/ 2009
186	RAPID CITY	Winter	13,333	5,205	2008/ 2009
187	RESTON	Winter	10,000	6,375	2008/ 2009
188	RIDING MOUNTAIN	Winter	7,550	5,080	2008/ 2009
189	RIVERS	Winter	10,000	7,293	2008/ 2009
190	ROBLIN GREENWAY	Winter	16,500	11,199	2008/ 2009
191	RORKETON	Winter	10,000	5,526	2008/ 2009
192	ROSSBURN	Winter	8,600	6,734	2007/ 2008
193	RUSSELL	Winter	18,250	7,729	2008/ 2009
194	SAN CLARA	Winter	3,510	1,713	2008/2009
195	SANDY LAKE	Winter	7,550	6,017	2008/ 2009
196	SHERGROVE	Winter	10,000	5,930	2008/ 2009
197	SHERRIDON	Winter	6,600	655	2008/ 2009
198	SHILO	Winter	8,400	4,923	2008/ 2009
199	SHILO DSC	Summer	5,400	4,005	2009
200	SHOAL LAKE	Winter	11,760	6,320	2006/ 2007
201	SHORTDALE	Winter	4,680	2,511	2008/ 2009
202	SIFTON	Winter	4,680	2,935	2008/ 2009
203	SIOUX VALLEY	Winter	10,000	7,023	2006/ 2007
204	SNOW LAKE	Winter	11,000	5,243	2009/2010
205	SOURIS	Winter	43,000	11,078	2007/ 2008
206	ST. LAZARE	Winter	4,680	2,225	2008/ 2009
207	STE ROSE	Winter	15,100	7,994	2008/ 2009
208	STE. CLAUDE	Winter	18,250	8,077	2008/ 2009
209	STRATHCLAIR	Winter	5,000	4,113	2008/ 2009
210	SWAN RIVER DITCH ROAD	Winter	10,000	7,582	2008/2009
211	SWAN RIVER VALLEY ROAD	Winter	43,594	25,740	2006/ 2007
212	THE PAS RALLS ISLAND	Winter	82,500	49,112	2008/ 2009
213	THE PAS RALLS ISLAND STEPUP	Winter	14,000	7,737	2008/ 2009

	Rural - West Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Measurement
214	TREHERNE	Winter	17,438	9,302	2008/ 2009
215	VIRDEN SOUTH	Winter	26,500	15,574	2008/ 2009
216	VIRDEN WALLACE	Winter	27,438	8,910	2008/ 2009
217	WASKADA	Winter	10,000	5,722	2008/ 2009
218	WATERHEN	Winter	10,000	3,699	2006/ 2007
219	WAWANESA	Winter	17,438	6,391	2008/ 2009
220	WAYWAYSEECAPPO	Winter	7,550	4,297	2008/ 2009
221	WINNIPEGOSIS NORTH	Winter	12,230	4,220	2008/ 2009
222	WINNIPEGOSIS SOUTH	Winter	3,440	1,369	2005/ 2006

	Rural - East Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
223	A.E.C.L.	Winter	14,850	3,589	2000/ 2001
224	Altona West	Winter	28,958	18,507	2008/ 2009
225	Arborg West	Winter	22,588	16,771	2008/ 2009
226	Ashern	Winter	13,300	12,240	2008/ 2009
227	Beausejour East	Winter	28,150	16,709	2007/ 2008
228	Berens River	Winter	4,644	3,835	2008/ 2009
229	Bird Lake	Summer	2,665	487	2008
	Bird Lake	Winter	3,745	630	2008/ 2009
230	Bisset	Winter	2,580	1,533	2008/ 2009
231	Black River	Winter	2,106	1,405	2007/ 2008
232	Bloodvein	Winter	4,644	1,890	2006/ 2007
233	Brereton Lake	Summer	12,500	2,835	2009
	Brereton Lake	Winter	13,300	3,915	2009/2010
234	Brokenhead	Winter	4,212	3,623	2007/ 2008
235	Cabot	Winter	14,850	11,328	2007/ 2008
236	Carman	Winter	28,958	17,570	2007/ 2008
237	Dallas	Winter	13,300	10,812	2008/ 2009
238	Darlingford	Winter	7,220	4,443	2008/ 2009

	Rural - East Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
239	Dominion City	Winter	6,795	6,024	2008/ 2009
240	East Selkirk	Winter	19,202	15,042	2008/ 2009
241	Elie	Winter	14,850	11,031	2008/ 2009
242	Elm Creek East	Winter	9,060	6,141	2007/ 2008
243	Elma	Winter	4,200	3,938	2007/2008
244	Eriksdale East	Winter	6,795	5,702	2008/ 2009
245	Finns	Winter	6,795	7,019	2008/ 2009
246	Fisher Branch	Winter	13,300	7,425	2008/ 2009
247	Fort Alexander DSC	Winter	7,020	4,282	2008/2009
248	Fraserwood	Winter	4,212	3,975	2008/ 2009
249	Garson	Winter	19,750	13,351	2007/ 2008
250	Gimli	Winter	20,385	17,337	2008/ 2009
251	Grand Beach	Winter	13,300	6,195	2008/ 2009
252	Graysville	Winter	2,808	1,605	2008/ 2009
253	Great Falls	Winter	2,808	2,211	2007/ 2008
254	Gretna Green	Winter	4,644	3,829	2008/ 2009
255	Grunthal	Summer	21,870	8,752	2009
	Grunthal	Winter	28,958	12,547	2009/2010
256	Gull Harbour	Winter	4,212	2,137	2008/ 2009
257	Gull Lake	Winter	13,300	3,770	2005/ 2006
258	Hadashville DSC	Summer	5,000	3,052	2009
	Hadashville DSC	Winter	7,020	4,538	2009/2010
259	Hodgson	Winter	14,850	9,603	2008/ 2009
260	Jordan	Winter	9,588	4,293	2007/ 2008
261	Komarno	Winter	13,590	6,110	2008/ 2009
262	La Broquerie	Summer	10,000	7,275	2009
	La Broquerie	Winter	13,300	12,457	2009/2010
263	Lac Du Bonnet	Winter	27,250	26,653	2007/2008
264	Letellier	Winter	13,300	8,324	2008/ 2009
265	Libau	Winter	13,300	4,395	2007/ 2008
266	Little Grand Rapids	Winter	9,288	4,597	2008/ 2009
267	Lowe Farm	Winter	13,300	4,208	2008/ 2009
268	Lundar	Winter	7,425	6,675	2008/ 2009

	Rural - East Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
269	Manigotagan	Winter	6,795	3,572	2007/ 2008
270	Manitou East	Winter	28,150	9,082	2008/ 2009
271	McTavish	Winter	14,850	6,979	2008/ 2009
272	Medika DSC	Summer	5,000	688	2009
	Medika DSC	Winter	7,020	827	2009/2010
273	Miami	Winter	6,795	5,306	2008/ 2009
274	Mitchell	Summer	0	9,502	2009
	Mitchell	Winter	0	9,524	2009/2010
275	Moosehorn	Winter	4,212	3,887	2008/ 2009
276	Morden Cheval	Winter	13,300	14,873	2008/ 2009
277	Morden Ninth	Winter	28,150	17,324	2008/ 2009
278	Morris	Winter	9,288	7,745	2008/ 2009
279	Netley	Winter	13,300	11,362	2008/ 2009
280	Niverville	Summer	11,520	10,042	2009
	Niverville	Winter	13,590	10,057	2009/2010
281	Notre Dame de Lourdes	Winter	3,096	5,069	2008/ 2009
282	Oakville	Winter	14,850	9,441	2008/ 2009
283	Parkdale	Winter	13,300	13,672	2008/ 2009
284	Pinawa North	Winter	11,880	8,227	2007/ 2008
285	Pine Falls	Winter	36,763	14,905	2005/ 2006
286	Piney DSC	Summer	5,000	2,247	2009
	Piney DSC	Winter	6,615	3,074	2009/2010
287	Plum Coulee	Winter	13,300	9,060	2008/ 2009
288	Poplar Point	Winter	6,795	6,068	2008/ 2009
289	Poplar River	Winter	5,418	2,820	2008/ 2009
290	Poplarfield	Winter	4,212	4,677	2008/ 2009
291	Portage 15th St	Winter	28,510	22,246	2008/ 2009
292	Portage la Reine	Winter	9,060	7,098	2006/ 2007
293	Portage Sask Ave	Winter	26,890	21,154	2008/ 2009
294	Portage Southport	Winter	4,644	5,812	2008/ 2009
295	Portage Westco Dr	Winter	28,150	12,374	2008/ 2009
296	Randolph	Summer	17,280	12,119	2009
	Randolph	Winter	22,275	17,786	2009/2010

	Rural - East Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
297	Richer North	Summer	10,000	6,345	2009
	Richer North	Winter	13,300	9,397	2009/2010
298	Riverton	Winter	14,850	8,425	2008/ 2009
299	Saltel	Summer	5,000	2,232	2008
	Saltel	Winter	6,795	7,649	2009/2010
300	Sarto	Summer	12,500	6,895	2009
	Sarto	Winter	13,300	8,937	2009/2010
301	Selkirk Mercy St.	Winter	37,125	37,270	2008/ 2009
302	Somerset	Winter	28,150	8,361	2008/ 2009
303	Sprague South	Summer	11,520	3,864	2009
	Sprague South	Winter	13,300	6,918	2009/2010
304	St Jean Baptiste	Winter	4,644	2,159	2008/ 2009
305	St. Laurent	Winter	7,207	7,986	2008/ 2009
306	St. Malo	Summer	10,000	6,202	2009
	St. Malo	Winter	13,300	7,335	2009/2010
307	St. Martin	Winter	13,300	9,165	2008/ 2009
308	St. Pierre	Summer	17,280	6,914	2009
	St. Pierre	Winter	20,725	9,819	2009/2010
309	Star Lake	Summer	11,520	7,717	2009
	Star Lake	Winter	14,850	7,680	2009/2010
310	Ste Agathe	Winter	6,795	5,665	2008/2009
311	Ste. Anne	Summer	17,280	11,905	2009
	Ste. Anne	Winter	20,725	17,926	2009/2010
312	Ste. Elizabeth	Summer	5,000	1,932	2008
	Ste. Elizabeth	Winter	6,795	4,392	2009/2010
313	Steeprock	Winter	4,212	1,976	2008/ 2009
314	Steinbach	Summer	42,100	26,773	2009
	Steinbach	Winter	50,425	31,873	2009/2010
315	Steinbach Loewen	Summer	11,520	13,297	2009
	Steinbach Loewen	Winter	27,714	12,914	2009/2010
316	Stonewall	Summer	23,040	15,637	2008
	Stonewall	Winter	29,700	27,643	2008/ 2009
317	Stony Mountain West	Winter	13,300	8,608	2007/ 2008

	Rural - East Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
318	Stuartburn	Summer	10,000	3,330	2009
	Stuartburn	Winter	13,300	5,280	2009/2010
319	Swan Lake	Winter	13,300	7,265	2008/ 2009
320	Teulon	Winter	28,150	13,790	2008/ 2009
321	Victoria Beach	Summer	10,000	4,597	2009
	Victoria Beach	Winter	13,300	7,912	2008/ 2009
322	Vita	Summer	5,000	3,726	2009
	Vita	Winter	6,795	4,831	2009/2010
323	Vivian	Winter	9,900	9,464	2007/ 2008
324	Warren	Winter	19,800	11,521	2007/ 2008
325	Westbourne	Winter	6,795	3,711	2008/ 2009
326	Whitemouth North	Winter	11,880	3,499	2007/ 2008
327	Whiteshell	Winter	17,944	5,572	2007/ 2008
328	Winkler Market St	Winter	28,150	36,318	2008/ 2009
329	Winkler North	Winter	28,150	21,299	2008/ 2009
330	Winnipeg Beach	Winter	14,850	13,171	2008/2009
331	Woodlands	Winter	9,747	6,778	2008/ 2009
332	Woodridge	Summer	5,000	2,503	2009
	Woodridge	Winter	6,795	3,594	2009/2010
333	Zhoda DSC	Summer	5,000	1,662	2009
	Zhoda DSC	Winter	6,795	2,137	2009/2010

	Rural - North Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
334	Churchill South	Winter	39,060	7,702	2008/ 2009
335	Cross Lake	Winter	31,388	13,192	2009/2010
336	Dunlop	Winter	2,106	198	2007/ 2008
337	Garden Hill	Winter	39,060	7,541	2009/2010
338	Gillam	Winter	22,275	9,501	2008/ 2009
339	Gods Lake Narrows	Winter	37,125	8,146	2008/ 2009
340	Ilford	Summer	5,850	950	2009
341	Ilford	Winter	7,740	1,915	2007/ 2008

	Rural - North Stations	Season	Loading Limit (kVA)	Last Measured Load (kVA)	Year of Last Measurement
342	Kettle	Winter	9,900	261	2008/ 2009
343	Leaf Rapids	Winter	37,125	3,427	2008/ 2009
344	Limestone	Winter	11,138	1,845	2008/ 2009
345	Lynn Lake Copper St	Winter	9,288	4,319	2004/ 2005
346	Nelson House	Winter	11,093	8,542	2008/ 2009
347	Norway House	Winter	14,850	16,979	2009/2010
348	Notigi	Winter	1,548	922	1995/ 1996
349	Oxford House	Winter	39,060	5,571	2008/ 2009
350	South Indian Lake	Winter	14,850	2,857	2004/ 2005
351	Split Lake	Winter	19,751	7,072	2009/2010
352	Thompson Burntwood	Winter	29,700	27,653	2009/2010
353	Thompson Mystery Lake	Winter	34,875	39,782	2008/ 2009
354	Thompson Oak St	Winter	3,483	3,113	2009/2010
355	Thompson Station Rd	Winter	3,483	4,215	2009/2010
356	Wabowden	Winter	7,740	4,531	2009/2010
357	Wasagamack	Winter	40,176	5,642	2007/2008

RCM/TREE/MH I-7

Rebalancing Energy and Demand Charges

Reference: Rebalancing Energy and Demand Charges, Appendix 13.7

q) Please estimate the percentage of transmission, subtransmission and distribution plant that is driven by the customer's individual maximum demand (that is, the billing units for demand charges).

ANSWER:

Allocation of costs of transmission, subtransmission and distribution is not driven by customer billing demand, but rather by diversified demand either coincident peak or non-coincident peak.

<u>RCM/TREE/MH I-8</u>

Proposed Rate Structure

Reference: Bill Comparisons, Appendices 10.5 and 10.6

f) Please indicate whether MH has considered proposing seasonally-differentiated rates for Residential and General Service non-demand rates

i. If not, explain why not.

<u>ANSWER</u>:

Manitoba Hydro has done some preliminary review of seasonally-differentiated rates for the Residential rate class. One method looked at increasing the size of the first block rate in the winter months and reducing the first block size in the summer months. This method would have the advantage of mitigating impacts on winter bills for those customers who have no choice but to use electricity to heat their homes.

In terms of customer impacts of a seasonally differentiated rate, the winter bill advantage would be offset, at least in part, by higher summer bills. Further, because the larger winter block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, implementing a seasonally-differentiated rate is more complex than the current rate structure. However compared to other potential TOU rate structures it is relatively easy to implement and for customers to understand. All residential services would be affected with two rate changes a year. Billing issues could be problematic for customers in the two rate change months as customers may notice the billing difference and would be more apt to contact the Contact Centre and/or their district office with enquiries. The major complaint would be unfairness of estimated bills and proration of bills.

RCM/TREE/MH I-46

Please provide a list of all Manitoba Hydro residential electric service charges not covered by an energy charge.

a) For all such service charges, please provide by month for the months October 2005 to present the revenue generated by that service charge;

ANSWER:

The following are residential service charges not covered by an energy charge:

- Late payment charge,
- Residential reconnection charge,
- Residential special reading fee,
- Residential returned cheque charge, and
- Residential Federal Meter Dispute charge.

Information is not readily available for residential customers prior to April 2006.

Please see Manitoba Hydro's response to RCM/TREE/MH I-43 for late payment charges billed to residential accounts by month for the period of April 2006 to December 2009.

The following table presents the reconnection charges billed to residential accounts by month for the period of April 2006 to December 2009.

Residential Reconnect Charges ($)

	2009	2008	2007	2006
December	$ 9 175	$ 6 315	$ 4 500	$ 6 060
November	19 520	15 565	26 150	20 310
October	21 820	27 850	41 125	42 455
September	37 440	40 045	40 950	44 485
August	44 400	52 415	50 285	49 912
July	65 580	77 950	53 135	52 125
June	67 150	87 400	61 170	46 295
May	35 860	64 955	80 055	38 165
April	22 880	16 645	42 805	9 743
March	14 470	9 990	8 415	
February	11 050	10 890	7 530	
January	7 315	10 175	9 635	

The following table presents the special reading fees billed to residential accounts by month for the period of April 2006 to December 2009.

Residential Special Reading Fees ($)

	2009	2008	2007	2006
December	$ 96 165	$ 82 265	$ 58 485	$ 49 185
November	89 045	77 245	66 480	87 865
October	50 360	67 640	58 380	37 075
September	68 760	64 360	59 605	37 860
August	61 920	53 920	54 185	42 748
July	69 320	60 325	48 300	45 180
June	66 375	54 885	50 120	70 020
May	65 030	48 840	56 000	24 180
April	61 610	57 240	64 720	13 551
March	83 120	53 050	45 410	
February	63 820	62 575	51 690	
January	72 335	59 215	52 855	

The following table presents the returned cheque charges billed to residential accounts by month for the period of April 2006 to December 2009.

Residential Returned Cheque Charges ($)

	2009	2008	2007	2006
December	$ 4 090	$ 4 840	$ 4 080	$ 5 240
November	4 720	4 560	5 060	7 000
October	4 740	5 320	5 140	6 560
September	4 800	5 880	5 540	6 900
August	5 840	5 540	6 980	8 640
July	7 000	7 340	8 100	8 920
June	8 100	8 260	8 820	11 260
May	6 520	7 360	9 000	11 300
April	6 060	7 240	7 440	9 320
March	7 200	6 380	6 900	
February	6 020	5 660	6 020	
January	5 780	6 640	7 580	

The following table presents the Federal Dispute Meter charges billed to residential accounts by month for the period of April 2006 to December 2009.

Residential Federal Dispute Meter Charges ($)

	2009	2008	2007	2006
December	$ 35	$ 70	$ -	$ 35
November	35	35	-	-
October	(35)	-	-	35
September	35	35	105	35
August	35	-	-	35
July	-	105	70	70
June	70	70	-	35
May	35	35	35	70
April	-	70	70	70
March	35	70	-	
February	-	35	35	
January	70	35	-	