June 3, 2016

Ms. Kirsten Walli
Board Secretary,
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

Re: EB-2015-0043 Rate Design for Electricity Commercial and Industrial Customers

In April 2015, the Ontario Energy Board ("OEB" or the "Board") announced a new distribution rate design for residential electricity customers. On May 28, 2015, the OEB described a process to begin identifying a new distribution rate design for commercial and industrial electricity customers. On March 31, 2016 the OEB issued for comment, a Staff Discussion Paper, "*Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors*" (the "Staff Paper"), which set out a series of options for the design of electricity distribution rates for commercial and industrial customers.

The Coalition of Large Distributors[1] and Hydro One Networks Inc. ("CLD/HONI") is pleased to provide the attached comments on the Staff Paper. CLD/HONI engaged an external consultant, Elenchus Research Associates Inc., to provide analysis and advice in the review of the proposed rate design options presented in the Staff Paper, however, the views expressed in the attached are those of CLD/HONI. These comments are being submitted after the date requested by the Staff Paper. CLD/HONI required additional time in order to provide a thoughtful and considered response to this important policy item.

CLD/HONI believes that utilities should be given flexibility in designing rates for their customers that best reflect customer needs and each utility's unique circumstances. A "One size fits all" rate design solution for all utilities in Ontario would not give utilities the tools needed to succeed under the current changing industry environment. Additionally, CLD/HONI is of the view that any new rate design to be adopted should take into

[1] The CLD members making these submissions is comprised of the following electricity Local Distribution Companies ("LDC"): Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited, and Veridian Connections Inc.

consideration implementation costs, guard against cross subsidization and stranded investment, and be responsive to the changing market dynamics.

CLD/HONI is concerned that some distribution rate design options proposed are likely to result in significant under recovery of the approved distributors' costs where the incentives are not economic in terms of distribution costs. Distribution rates should not be used as a vehicle to encourage customers' participation in Conservation and Demand Management ("CDM") activities where there is no direct benefit to customers' distribution costs and no opportunity for distributors to recover lost revenues. To the extent that customer savings (i.e., lost distributor revenue) are not offset by distributor cost savings, a Lost Revenue Adjustment Mechanism ("LRAM") is essential to ensure the full recovery of distribution costs.

CLD/HONI submits that other than fully fixed rates, none of the demand based options fully address the need for recovery of costs of distribution assets that are required to be in place for those times when behind the meter generation is not available. Eliminating the standby charge without the introduction of gross load billing or another method of recovering these costs, would result in all other customers subsidizing the recovery of these costs.

CLD/HONI has not provided specific rankings of each of the options but instead offers detailed comments on the pros and cons of each of the options based on the high-level analysis provided in the Staff Paper. More detailed analysis is required to fully understand the implication of the rate options on the utility and its customers in order to be able to provide an informed ranking of the options.

CLD/HONI suggests that a working group be established to provide detailed analysis of the impact of the options.

CLD/HONI appreciate the opportunity to provide the attached comments and look forward to the opportunity to participate further in this process.

Please do not hesitate to contact me if you have any questions or require any further information.

Yours truly,

Original signed by Indy J. Butany-DeSouza

Indy J. Butany-DeSouza, MBA
Vice President, Regulatory Affairs
Horizon Utilities Corporation
Tel: (905) 317-4765
Cel: (416) 451-1822

indy.butany@horizonutilities.com

Submitted on behalf of CLD/HONI

Gia M. DeJulio
Enersource Hydro Mississauga Inc.
(905) 283-4098
gdejulio@enersource.com

Indy J. Butany-DeSouza
Horizon Utilities Corporation
(905) 317-4765
indy.butany@horizonutilities.com

Greg Van Dusen
Hydro Ottawa Limited
(613) 738-5499 x7472
gregoryvandusen@hydroottawa.com

Colin Macdonald
PowerStream Inc.
(905) 532-4649
colin.macdonald@powerstream.ca

Andrew Sasso
Toronto Hydro-Electric System Limited
(416) 930-7023
regulatoryaffairs@torontohydro.com

George Armstrong
Veridian Connections Inc.
(905) 427-9870 x2202
garmstrong@veridian.on.ca

Henry Andre
Hydro One Networks Inc.
(416) 345-5124
henry.andre@hydroone.com

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Submission of the Coalition of Large Distributors

And

Hydro One Networks Inc.

Ontario Energy Board Staff Discussion Paper

Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors

June 3, 2016

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Executive Summary

The Coalition of Large Distributors together with Hydro One Networks Inc. ("CLD/HONI") is pleased to have the opportunity to comment on the Ontario Energy Board ("OEB" or the "Board") Staff Discussion Paper *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors* (the "Staff Paper"). This process is an important step in the on-going evolution of the regulatory framework for the electricity distribution sector.

The New Rate Design Must be Future Oriented

This review is very timely. The power sector in Ontario is facing important technological and market transitions that will create challenges for distributors. Introducing rate designs that anticipate the changing needs and expectations of our customers will be an important step in preparing for the future.

The proposed rate design options focus on the importance of economic incentives as a determinant of the behaviour of customers. Future OEB policy processes will have to address other implications of the evolving opportunities and incentives that are motivating new entrants to encroach on the revenue base of Ontario's electricity distributors. This is particularly relevant as the scope of naturally monopolistic distribution activities is diminished by technological and business innovation.

One challenge that needs to be confronted is the risk that rates based on fully allocated embedded costs may be undermined by future off-grid options for some customers. An increasing number of customers are motivated to seek off-grid options due to the high cost of grid power when the Global Adjustment ("GA") is included in the billed amount. Customers moving off-grid will result in the shifting of costs to the remaining customers and the possible stranding of assets. For this reason, regardless of the ultimate rate design the OEB decides in this policy consultation, CLD/HONI feels strongly that the OEB needs to remain open and flexible to alternative rate proposals that any individual LDC may propose in the future to address the needs of its customers and its utility. As has been demonstrated in the Staff Paper and in the comments below, one size does not fit all.

The Industry is Diverse

CLD/HONI's comments on the identified rate design options have considered the diversity in energy usage across distributors and among each distributor's customers. The reality is that the number, type, and consumption of larger volume customers varies dramatically across distributors. Some large customers will be far more responsive than others to the price signals implicit in any rate design change. Given the small number of large volume customers, the response of only a few customers will have impacts that will be difficult to

predict in terms of both the shifting of costs among customers within a class and the potential revenue loss experienced by the distributors. The transition to any new rate design will have to be managed carefully to avoid harmful impacts to both customers and distributors.

CLD/HONI notes that implementing new rate designs in light of the potential implementation costs and customer impacts should be undertaken cautiously given that the current rate design for most of the classes under consideration already includes components addressing fixed and variable distribution cost drivers.

For these reasons, it is extremely important that in the next phase of this process, Board staff undertake analysis along the lines of that provided in Appendix A of the Staff Paper for a larger sample of distributors. Analysis based on the average bill impacts for a few distributors may be misleading about the impact of implementing the same changes across all Ontario distributors. It will be essential to undertake LDC-specific analysis across a broad range of LDCs to fully understand the impact of the proposed rate design changes on customers.

While Board staff have undertaken consultations and received generic feedback from a broad range of stakeholder groups, the recently announced Consumer Engagement Framework provides a number of new tools for gaining additional insight into the acceptability of the options under consideration. In particular, it will be valuable, as part of the next phase of the process, to gain an improved understanding from individual customers about their sensitivity to the distribution rate design options and associated bill impacts.

CLD/HONI anticipates that LDC specific analysis and additional customer engagement will demonstrate that the industry's diversity should be matched by rate design flexibility that allows each distributor to tailor its rate designs to the specific needs of its customers and the makeup of its customer classes.

EVALUATION CRITERIA USED BY THE CLD/HONI

CLD/HONI has incorporated the Board's objectives identified in the Staff Paper, as well as other well accepted rate design principles, to develop the following six evaluation criteria to assess the rate design options set out in the Staff Paper:

1. **Innovation:** Does the option support innovation for customers, given the evolution of supply, by facilitating customer choice and access to energy options?
2. **Incentive for Efficiency:** Is the option consistent with the efficient utilization of the distribution system in the short and in the long term (i.e., reduces the need for future investments in distribution assets and avoid uneconomic bypass)?
3. **Financial Prudence:** Does the option help to stabilize distribution revenue and provide distributors with a reasonable opportunity to recover all of their allowed costs?

4. **Cost transparency:** Does the option help increase customer understanding of the fixed nature of distribution costs and will it result in a rate design that is acceptable to customers in that it is simple to understand and perceived as fair? Are the appropriate distribution cost drivers being used?
5. **Equity:** Does the option recover an equitable share of costs from the various customer classes and from individual customers within a class?
6. **Practicality:** Is the option practical in terms of: reasonable rate/bill impacts; rate stability; and cost to implement and maintain?

In addition, and importantly, CLD/HONI notes that since the subject of this process is the distribution rate design for commercial and industrial ("C&I") customers, the scope of these objectives should be limited to the distribution system. Hence, it is CLD/HONI's view that the rate design objectives must encourage innovations that will benefit the cost or quality of distribution services, and improve the efficiency of the distribution system. Distribution rates should not be designed for the purpose of pursuing transmission or generation related objectives.

RATE DESIGN FOR GS<50KW CUSTOMERS

CLD/HONI sees merit in the **Fully Fixed Charge** for smaller volume commercial and industrial customers. It is consistent with the OEB's policy for Residential rate design; it is easily understood; and it reflects the fact that distribution costs do not vary with throughput in the short run. Many smaller GS<50kW customers are similar to the residential class that is already being transitioned to a fully fixed distribution charge. As customer volume increases, however, the volumetric component of cost causality also increases.

CLD/HONI notes that a full scale implementation of a Fully Fixed Charge for the GS<50kW class would result in large percentage increases to the distribution charges for many customers of some distributors (especially those that currently have low fixed monthly customer charges). However, in terms of absolute dollars and total bill, the impact may be considered acceptable for commercial customers, in general.

The option of **Time of Use Distribution Rates** has merit for distributors with capacity constraints. However, the bulk of the facilities of most distributors are not constrained. Hence, a time of use price signal will have minimal impact in terms of increasing the efficiency of the utilization of the distribution networks of these distributors. Furthermore, location-specific feeders that are constrained are impacted more by the local customers' non-coincident peak than by either the system coincident peak demand or peak period energy usage. The Time of Use option will not provide an incentive that is targeted on opportunities to avoid incurring future capacity costs. The Time of Use option is also anticipated to decrease rate stability for customers as distributors would be required to

adjust their rates in response to shifting consumption patterns driven largely by commodity prices.

CLD/HONI notes that the Time of Use option differs from the current kWh billing method in terms of the creation of separate on-peak and off-peak rates, which will add complexity to the overall billing regime and increase implementation costs. CLD/HONI is also concerned that the appropriate on-peak periods for the distribution system may differ from those for the existing commodity time of use periods which will create customer confusion and increase customer resistance to this option.

One final consideration for this option is that CLD/HONI believes that the incentives associated with the Time of Use distribution rates are likely to be quite muted since they will be dwarfed by the commodity TOU incentive. GS<50kW customers that are not already responding to existing TOU commodity rates are unlikely to respond to the incremental incentive of a TOU charge for distribution.

The option of **Energy Use Blocks** will, in the view of CLD/HONI, be unduly complex for most GS<50kW customers since they will have to anticipate their usage and continuously manage it in order to avoid overage charges, unless they simply opt to contract for a larger than required block of on-peak usage. The greatest incentive benefit will be achieved by implementing a large number of small blocks since the incentive is only relevant to customers at the boundaries between blocks. If simplicity is achieved by adopting a small number of blocks, the intended incentive effect will be lessened. This approach is likely to cause significant customer dissatisfaction. This option also presents substantial implementation and ongoing administration costs for distributors. In particular, this plan, colloquially known as the “cell phone plan”, is likely to drive customer frustration and increased call volume and length of calls for LDCs’ call centres, thereby increasing distributors’ costs. For all of these reasons, CLD/HONI submits that this option is the least appealing of all GS<50kW options presented.

CLD/HONI believes that a **Minimum Bill** could be an effective means of designing an option that balances the considerations presented above. It is important to recognize that the intent of establishing a minimum bill is to establish a minimum level for recovering a fair share of the total costs of the distribution system. As such, it is not appropriate to use the current PLCC methodology as a reference point for the fixed distribution charges. CLD/HONI believe that the minimum bill should be set to ensure that every customer contributes an appropriate minimum amount towards the recovery of the utility’s recoverable costs, consistent with what is currently paid by a typical smaller volume user (e.g. 25th percentile consumption).

The Minimum Bill could have the flexibility of being set at a high enough level to serve as a fully fixed charge for the smaller volume users in the GS<50kW class, or for all users if an LDC believes the impacts are manageable. Considerations would include the current

level of its fixed monthly charge and the extent to which its distribution facilities have broad capacity constraints.

In summary, CLD/HONI recommends that the OEB approve rate design options for distributors to consider that suits the needs of customers and distributors. The CLD/HONI believe that the Fully Fixed and Minimum Bill rate designs are viable options to be considered by the OEB. While the Fully Fixed charge may cause significant distribution bill impacts, it may be the preferred option from the customers' perspective due to the low dollar impact. Replacing the fixed charge component of the existing GS<50kW rate structure with the Minimum Bill concept could strike the best balance between understandability, customer acceptance and providing incentives for innovation and efficiency. Under the Minimum Bill option, a revenue neutral rate design would result in a higher kWh charge, where the energy corresponding to the minimum bill would not incur a charge, while usage above that minimum would incur a charge that is higher than the current kWh rate. This change should be implemented on a distributor-specific basis in a manner that minimizes customer disruption while increasing the kWh component to a level that encourages the efficient use of the distribution system.

RATE DESIGN FOR GS>50KW CUSTOMERS, INCLUDING INTERMEDIATE AND LARGE USE

CLD/HONI believes that the pros and cons of the options identified for the GS>50kW, Intermediate and Large Use classes, all of which are currently billed on a fixed charge plus demand rate basis, are very similar for all classes. The one important difference is that the Intermediate and Large Use classes typically have a small number of customers, relative to the distributor's total number of customers.

When the number of customers in a class is small, any distribution rate design that differentiates between on-peak and off-peak period rates is likely to be problematic for two reasons. First, if one customer has greater ability to shift demand, the result could be significant shifting of costs among customers within the class. Second, when a large customer responds to the incentive and shifts its demand, it is unlikely to increase the efficiency of the utilization of the distribution system since larger customers are frequently the dominant users of the feeders on which they rely. Shifting customer demand will simply shift the peak demand period on the facilities that serve them, which provides no benefit to their local feeders.

The two rate design options identified in the Staff Paper for each of these three classes are a Three Part Demand Rate and Time of Use Demand**.** The essential difference between these two time-differentiated rate designs is that with the former, one of the rate components is based on the maximum demand at any time, and with the latter it is based on the maximum demand during the off-peak period. Both options have a peak period demand charge based on the maximum demand during the peak period.

While CLD/HONI sees some merit to both of these options, the Time of Use Demand would be more consistent with the existing Time of Use commodity pricing which has the advantage that customers have been acclimatized to on-peak and off-peak commodity charges in Ontario. This would create similar drivers for commodity and distribution pricing which may facilitate customer understanding. In addition, customers that have high maximum demand in the on-peak period but low maximum demand in the off-peak period may be resistant to high charges under both rate periods as defined by the Three Part Demand option.

Many of the same concerns raised with the GS<50kW TOU distribution rate option would also apply to both GS>50kW distribution rate design options. In particular, any incentives created by the distribution pricing options are likely to be even more muted for the GS>50kW customers since the distribution portion of their bill typically represents less than 15% of the total bill. GS>50kW customers that do not already respond to existing commodity pricing incentives are unlikely to respond to the incremental incentive of a time-differentiated charge for distribution.

Implementation and maintenance costs would be material, and are expected to be similar under both options. Further, the benefit of either of the two time-differentiated rate design options as compared to the existing any time demand charge is minimal and may cause load shifting that may result in no efficiency benefit for the distribution system. The fully fixed charge option may be a preferred option for some distributors where load shifting or demand reduction is not likely to reduce distribution costs in future years. In cases where the objective is to reduce peak demand whenever it occurs, which would be relevant in the case of the GS>50 class, the optimal rate design could be to continue with the current peak kW billing determinant but also apply the minimum bill concept so as to increase the kW charge for customers that exceed the minimum bill threshold.

Notwithstanding the above discussion related to time-differentiated demand rates proposed in the Staff Paper, CLD/HONI supports flexibility in LDC's proposing fully fixed rates for the GS>50 classes where the distributor believes it would be appropriate and manageable[2].

In summary, CLD/HONI believes that options should be available to distributors to implement rate designs that best suit their needs and the needs of its customers. Similar to its view on the options for GS<50kW customers, CLD/HONI believes that it would be appropriate for distributors to have the option of introducing a Fully Fixed or Minimum Bill rate design for customers in each of the larger volume classes. A minimum bill will not

[2] While a single fixed charge might create significant bill impacts for some distributors with diverse levels of demand within classes, a means of addressing this would be to implement more than one fully fixed charge for customers at different levels of demand within the rate class. This would lessen the impact on customers' bills and recognise the current embedded cost of the distribution system.

always be appropriate; hence, it should not be mandatory. Nevertheless, it may serve as an important option for dealing with situations where customers wish to maintain their distribution connection despite meeting most of their requirements through behind-the-meter generated generation.

LOST REVENUE

CLD/HONI is concerned that adopting any time-differentiated distribution rate design could result in significant under recovery of the approved revenue requirement for distributors. Distribution rates should not be used as a vehicle to encourage customers' participation in CDM activities where there is no direct benefit to customers' distribution costs and no opportunity for distributors to recover lost revenues. A Lost Revenue Adjustment Mechanism ("LRAM") is essential to the preservation of revenues of distributors.

CLD/HONI emphasizes that distributors will need significant latitude in setting the ultimate level of each component of any new rate design, and transitioning customers to the new rate design, in order to minimize the impact on customers as well as the potential under recovery of costs. Even with this latitude, if time-differentiated charges are implemented for distribution rates, the customer response will be difficult to forecast resulting in potentially significant revenue impacts. Distributors therefore will not have a reasonable opportunity to recover their costs under the current Board incentive regulation regime, unless some version of a lost revenue adjustment mechanism is implemented to address potentially large unanticipated variances from forecast billing determinants.

An option to assess the potential impact on customers and on distributor revenues may be to encourage a few distributors to act as early adopters or to initiate a limited pilot program of the new rate design. This would provide valuable information on how customers respond that could subsequently be used to establish rates that reasonably reflect the anticipated degree of customer response

STANDBY RATES AND DISTRIBUTED ENERGY RESOURCES

OEB Staff's paper indicates that one of the goals of new rate design is to "avoid the need for specialized rate classes for load displacement generation and net metered customers and charges like standby rates". CLD/HONI submits that other than fully fixed rates, none of the demand based options being considered fully address the need for recovery of costs of distribution assets that are required to be in place for those times when behind the meter generation is not available. Eliminating the standby charge without the introduction of gross load billing or another method of recovering these costs, would result in all other customers subsidizing the recovery of these costs. CLD/HONI does not believe that any distribution rate design method on its own can achieve the desirable goal of facilitating the efficient use of distributed energy resources ("DER") within Ontario's integrated electricity system. CLD/HONI urges the Board to undertake a follow-up

process to address these issues in the very near future, and further submits that standby charges should not be eliminated by the OEB in the interim.

NEXT STEPS

CLD/HONI recognises the effort of OEB staff to provide the high level analysis of selected data provided by CLD/HONI. However, a more detailed analysis for a broader sample of distributors is required to properly rank the options in order of preference as requested in the OEB Staff letter issued March 31, 2016. CLD/HONI suggest that the OEB establish a working group of a cross section of distributors to assist in the detailed analysis that is required to fully understand customer and distributor impacts of each of the proposed rate designs. The CLD/HONI would be pleased to provide support at the working group level.

CLD/HONI also believes that future OEB policy processes will have to address the implications of the technological and business innovation opportunities that are impacting the naturally monopolistic activities of Ontario's electricity distributors, where those implications are not addressed adequately by rate design alone.

1 INTRODUCTION

This submission has been prepared by the Coalition of Large Distributors[3] together with Hydro One Networks Inc. ("CLD/HONI") in response to the Staff Discussion Paper, *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors* (the "Staff Paper") (EB-2015-0043).

CLD/HONI believes that this review is a timely and important continuation of the process of reviewing and updating the design of customer rates that commenced in 2007 (EB-2007-0031) with the Rate Design Review. The most recent step in modernizing the design of rates for electricity customers was the report released by the Ontario Energy Board ("OEB" or "Board") in April 2015, Board Policy: A New Distribution Rate Design for Residential Electricity Customers (the "April Report").

This process is an important step in the on-going evolution of the regulatory framework for the electricity distribution sector. The renewed regulatory framework incorporates mechanisms for transitioning toward an outcomes based approach to regulation that recognizes the importance of incentives as a determinant of the way distributors will manage their businesses in the future. This process focuses on the importance of financial incentives as a determinant of the behaviour of customers. Future OEB policy processes will have to address the implications of the evolving opportunities and incentives that are impacting the naturally monopolistic activities of Ontario's electricity distributors as that monopoly is diminished by technological and business innovation.

CLD/HONI recognizes that the scope of this policy process is limited to revisions to the current rate design within the context of the current approach to determining the cost of service, which establishes rates that reflect fully allocated costs. It does not take into account competitive market cost concepts such as short run and long run marginal costs. Until issues related to the risk of uneconomic bypass of distribution service are addressed, there will be a risk that the evolution of the industry, including rate design changes, may lead to revenue loss for distributors and the risk of stranded assets.

CLD/HONI notes that in the face of non-utility alternatives to distribution services, such as self-sufficient micro-grids, it is only a matter of time until competitive alternatives to utility distribution services are offered to our customers at prices that are below fully allocated cost but above our marginal cost. If distributors cannot respond appropriately to innovative competitive offerings as they become available, there is a risk that some of our customers will opt for alternatives that constitute uneconomic bypass. This will lead to

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[3] The Coalition of Large Distributors ("CLD") consists of Enersource Hydro Mississauga Inc. ("Enersource"), Horizon Utilities Corporation ("Horizon Utilities"), Hydro Ottawa Limited ("Hydro Ottawa"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("Toronto Hydro"), and Veridian Connections Inc. ("Veridian").

stranding of assets and revenue erosion for distributors that will burden remaining customers with ever increasing rates. It will be important to adopt rate designs that set the stage for the future evolution of the Ontario's electricity market and for the OEB to initiate further policy processes that address the implications of the anticipated transformation of the industry and build on the forthcoming rate design changes.

1.1 THE COALITION OF LARGE DISTRIBUTORS

CLD/HONI provide distribution services to approximately 64% of Ontario's C&I electricity customers. The following table summarizes the customers by class for CLD/HONI.

Customers Served by the CLD and Hydro One

Distributor	Residential	GS<50kW	GS>50kW	Sub Transmission	Large Use	Total Customers
Enersource	179,182	17,809	4,359		9	201,359
Horizon Utilities	219,536	18,464	2,065		11	240,076
Hydro One Networks	1,106,663	104,083	7,984	562	-	1,219,292
Hydro Ottawa	291,759	24,149	3,617		11	319,536
PowerStream	316,596	31,897	4,789		2	353,284
Toronto Hydro	661,959	71,387	10,864		42	744,252
Veridian	107,574	8,874	1,044		2	117,494
Total	2,883,269	276,663	34,722	562	77	3,195,293
Industry Total	4,502,650	430,842	54,688	562	117	4,988,859
% of Total customers served by CLD and Hydro One	64%	64%	63%	100%	66%	64%

Source 2014 OEB Yearbook

1.2 STRUCTURE OF THE SUBMISSION

The CLD/HONI submission is comprised of five additional sections. Section 2 contains background comments that frame important aspects of the context within which CLD/HONI's views are framed. Section 3 discusses a number of generic issues that were identified in the Staff Paper but do not relate to any particular option. Sections 4 and 5 set out CLD/HONI's evaluation of the identified options with respect to GS<50kW and all larger volume customers, respectively. The three larger rate classes GS>50kW, Intermediate and Large Use are discussed together since the options are the same and the comments are essentially the same in relation to each of those customer classes. Section 6 summarizes the conclusions and recommendations of CLD/HONI as contained in this submission.

2 BACKGROUND TO THE CLD/HONI'S COMMENTS

This section addresses a number of issues that CLD/HONI believes to be important contextual considerations that are relevant to the assessment of the rate design options contained in the Staff Paper.

2.1 C&I RATE DESIGN OBJECTIVES AND EVALUATION CRITERIA

CLD/HONI's assessment of the rate design options explicitly examines the options in terms of their consistency with the Board objectives as set out in its May 28, 2015 document titled Rate Design for Electricity Commercial and Industrial Customers EB-2015-0043, with the addition of objectives that CLD/HONI view as implied by the discussion in the Staff Paper.

The Objectives section of the Staff Paper links back to the objectives of the residential fixed rate design as established in the April Report. Two of those objectives appear to extend the Objectives set out in the Board's May 28, 2015 statement for the C&I rate design process:

- *… simplicity and increasing customer understanding of the fixed nature of the distribution service.*
- *Customers should pay their fair share for the assets and services that they use and receive fair value for the services that they provide.*

CLD/HONI interprets these identified OEB objectives as broadly applicable to the evolution of the regulatory framework within which the industry should be operating in the future as technological innovation drives the transformation of the industry toward a more competitive structure with increased customer choice. The implication is that rate design matters, which are the focus of this policy process, are not the only policy innovations that will be needed in order to achieve these policy objectives in the coming years. CLD/HONI, therefore, hold the view that it is important to consider the issues that are within the scope of this policy process in the context of the longer term trends anticipated for the electricity sector. The rate design policies that are adopted at the end of this process should set the stage and be consistent with the further evolution of the sector's regulatory framework in the coming years and decades.

CLD/HONI has identified a set of evaluation criteria based on the objectives identified by the Board and Staff as discussed above, as well as taking into consideration other well accepted design principles. CLD/HONI believes that the full set of objectives work together to achieve the overarching goal contained in the title of the Staff Paper - aligning the interests of distributors and customers.

1. **Innovation:** intended to capture the Board's first main objective (and sub-objectives): *To support innovation for customers given the evolution of supply*. It also encompasses the expanded commentary contained in the Staff Paper related to customer choice and access to energy options.
2. **Incentive for Efficiency:** intended to capture the Board's second main objective (and sub objectives): *To increase efficiency*. It also captures the expanded commentary contained in the Staff Paper related to encouraging use by customers of DER where it is efficient to do so and does not constitute uneconomic bypass. Efficiency has both long and short term considerations. It relates to both maximizing the use of existing assets and reducing the need for future distribution investments.
3. **Financial Prudence:** intended to capture the Board's third main objective (and sub objectives): *To stabilize distribution revenue*. CLD/HONI also considers this to include the associated objective of providing distributors a reasonable opportunity to recover all of their costs including their cost of capital. This objective is at the core of ensuring that the sector remains financially healthy and able to invest in order to maintain a safe, reliable distribution system.
4. **Cost transparency:** captures the objective identified in the Staff Paper: *To increase customer understanding of the fixed nature of distribution costs*. The CLD/HONI also considers it to include a consideration of whether the rate design is acceptable to customers in that it is simple to understand and perceived as fair.
5. **Equity:** reflects a further goal identified in the Staff Paper although it is not explicitly identified in the Board's May 28 statement of objectives: *To recover an equitable share of distribution costs from the various customer classes*.
6. **Practicality:** captures a number of important considerations including reasonable rate/bill impacts, rate stability, and considerations related to implementing and maintaining the new rate designs. Evaluation of the options needs to recognize that the new rate design, and the transition to it, will have to be implemented in a manner that is consistent with Board's RRFE that establishes a formulaic approach to re-setting rates for 5 years.

CLD/HONI observe that there are likely to be inherent conflicts in realizing these objectives. For example, introducing a rate design that best realizes the objective of increasing efficiency, may sacrifice the equitable recovery of fully allocated embedded costs. It should also be noted that in the view of CLD/HONI the objective of simplicity, while relevant for the design of C&I rates, is generally of secondary importance for larger volume customers.

CLD/HONI note that since the subject of this process is the <u>distribution</u> rate design for C&I customers, the scope of these objectives should be limited to the distribution system. Hence, it is CLD/HONI's view that the rate design objectives must encourage innovations

that will benefit the cost or quality of distribution services, and improve the efficiency of the distribution system. Distribution rates should not be designed for the purpose of pursuing transmission or generation related objectives.

A distribution rate design based on non-distribution cost drivers would not achieve cost transparency or equity for customers. Where generation, transmission and distribution goals and incentives are not aligned, the most efficient and transparent approach is to set the individual charge components appropriately, rather than designing distribution rates in a way that reflects non-distribution cost drivers.

2.2 OEB STATED ISSUES

The Board's May 28, 2015 document identified five issues "to use to lead discussion with the stakeholder groups" and invited stakeholders "to suggest other issues that they believe are crucial to a successful outcome." The CLD/HONI's comments on each issue are provided below.

1. *Valuing connection to the system: The Board has typically allocated costs to a fixed charge based on a minimum system process. Given the Board's policy, what is the appropriate approach?*

The traditional approach to "valuing connection to the system … based on a minimum system process" calculates value on the basis of the Board's cost allocation model which implicitly defines value on the basis of fully allocated embedded costs. This approach is an appropriate approach for postage stamp rates that are designed to recover each distributor's embedded costs with standardized rates for all customers within a class. This conceptual framework for rate setting will not be sustainable in the evolving context envisioned in the Staff Paper. CLD/HONI agrees that "these advancements will enable greater consumer autonomy" with unregulated service options being offered in competition with utility services. In this context, the average connection cost may not correspond to the value of grid connection for different types of consumers. For example:

- A commercial prosumer[4] with rooftop solar installed[5] may value the connection to the grid as a storage option and a necessary asset for trading power when production exceeds its demand, in addition to a means of being able to purchase power from the grid. The value of the connection for this prosumer will be much greater than the value to a traditional consumer.
- A hospital that requires absolute reliability will, in the future, have many options for its primary power supply and its backup power. The potential uses of the grid could

[4] As defined at page 12 of the Staff Paper.

[5] This discussion envisions a future where rooftop solar and other DER resources are no longer subsidized but are simply economic options for a customer meeting its electricity needs.

include interconnected backup supplies, with several customers (such as the group of hospital clustered on University Avenue in Toronto) coordinating backup through a mini-grid. Again, the value of the grid connection would differ for different configurations for their grid connections.

- An industrial customer with load displacement generation may be supplying a significant portion of its demand using the load displacement generation, but when the generation is down it will rely on the distribution system of the utility to fully supply their needs. For these customers, a fixed charge tied to a "minimum system" calculation under the OEB's current cost allocation model does not reflect the true value of the grid connection in providing backup supply.

CLD/HONI believes that valuing the connection also needs to be considered in the context of challenges that could arise as a result of distributors being required to maintain rates based on fully allocated embedded costs for all customers, while non-utility options will be available to some customers on the basis of competitive market pricing. If the competitive playing field remains uneven, there is a risk that distributors will be faced with stranded costs at some time in the future when the cost of energy solutions that allows customers to disconnect from the grid become commercially viable. These solutions may constitute uneconomic bypass if distribution rates cannot be set to reflect value as distinct from embedded cost.

2. *Valuing capacity: What price signals will align the interests of customers and distributors to maximize use of the system and contain long-term costs?*

It is a fact that for most, if not all, C&I customers, the key price signals they will respond to are those signals associated with the commodity portion of their bill. Commodity typically represents 50% or more of their bill, as compared to 10-20% for distribution costs (a portion of which is recovered via fixed charges already). As such, if a customer has to choose between price signals that drive their commodity cost versus distribution cost, their focus will be on the commodity. Distribution pricing may provide incrementally larger signals, but it is unclear as to whether that would be a meaningful driver for many C&I customers to modify consumption patterns.

Under the current regulatory paradigm, value is treated as being indistinguishable from cost. But this approach works only because the true value to the customer generally significantly exceeds the embedded costs and the customer does not have access to competitive alternatives. However, as competitive alternatives to grid power emerge, competitive market pricing considerations (i.e., pricing is flexible as long as it exceeds marginal cost) will have to replace the current approach to valuing capacity for rate-setting purposes for some customers. Establishing mandated prices based on marginal costs will be difficult or impossible since conceivable scenarios could impact marginal costs in ways that are currently uncertain. For example:

- If an escalating price on carbon drives the transportation market to transition from gasoline to electric vehicles, some portions of existing distribution grids could become strained, requiring capacity upgrades.
- At the same time, increased reliance on self-generation could reduce the demand on other segments of distribution grids.

The CLD/HONI makes the following observations about valuing capacity in the evolving electricity market.

- A system that has excess peak capacity should not be providing incentives for moving off-peak since there is no resulting avoidance of distribution costs.
- Similarly, in general, there is no benefit to avoiding peaks during fall and spring periods since the distribution system is operating at well below peak capacity level.
- The occurrence of "peaks" and "capacity constraints" do not coincide among different LDCs or even for different segments within an LDC's system.

Valuing capacity by setting efficient price signals will require an entirely new approach to determining the appropriate price signals that relies on marginal costs, not embedded costs. Consideration of these future implications envisioned by the Staff Paper is beyond the scope of the rate design issues under consideration at this time; however, the fact that the challenges cannot be addressed by rate design changes alone, highlights the critical importance of the Board implementing follow up processes to address new approaches to valuing capacity and connection to the system. This will be important as the market evolves in response to technological innovation, increasing customer expectations and declining costs of alternatives to grid-distributed power that are based on centralized generation and storage.

3. *Valuing distributed energy resources: What treatment of distributed energy resources would recognize the costs and benefits of these resources to the system? What are the implications for customers who do not participate?*

The value of DER derives primarily from their potential impact in the integrated electricity system as generation and transmission resources. DER has limited potential as a substitute for distribution resources. Hence, the value of DER from the perspective of a distributor will be very different than the value of DER from the perspective of a DER customer, DER service providers and the Ontario power system as a whole.

For purposes of the current process, the comments of CLD/HONI address DERs, only as it relates to the distribution system.

CLD/HONI's comments on DER appear in section 3.2 of this submission.

4. *Rate stability: Customers moving from one rate class to another can find that their bill changes dramatically. How can Commercial/Industrial rates be designed to avoid that sudden transition at the boundaries of rate classifications?*

CLD/HONI notes that the Staff Paper in the section on the scope of this rate design process at page 3 states that "[t]o the extent possible, the OEB will maintain existing rate classification in order to avoid causing changes to the underlying cost allocation to classes." This constraint on scope removes a potentially important option for dealing with the concern about bill discontinuities at class boundaries.

Under the current options proposed by Staff, the differences in design between the GS<50 and the GS>50 classes could result in large bill shifts for customers reclassifying between these two classes. This issue has not been fully explored as part of the Staff's high level analysis of the options.

CLD/HONI notes that boundary discontinuities are an almost inevitable result of adopting different rate designs for different classes, particularly with changes to the current rate classifications being out-of-scope for this process. However, the issue could be somewhat mitigated by increasing the fixed component of the Distribution charge and by how the Minimum Charge is defined for the GS<50 and GS>50 customers.

5. *Rate goals: The Board has identified the objectives for the rate design. Stakeholder comments on the residential project suggested that, within those objectives, a desirable rate design would be: cost driven; customer controlled; and forward looking. Are these the appropriate goals?*

CLD/HONI agrees that a desirable rate design will be cost driven, customer-responsive, and forward looking. These features of a desirable rate design are embedded in the objectives used as the basis for the evaluation criteria in this submission. CLD/HONI has serious reservations, however, about the ability of these goals to be realized through rate design alone. They can only be realized through follow-up processes that address more fundamental issues related to the regulatory framework, rate-setting flexibility and the concept of cost used for rate setting purposes.

Section 3 discusses additional issues that CLD/HONI believe[s] are crucial to the successful outcome of this process.

2.3 UNDERSTANDING OUR CUSTOMERS

CLD/HONI provides a brief overview of the C&I customers it serves as a means of highlighting their diversity, as well as across the different LDCs. Appendix A provides additional information that further illustrates this diversity within individual LDCs. CLD/HONI expects that the diversity across all Ontario distributors will be much greater

than it is across the top seven with the largest numbers of customers. This diversity highlights the challenge of determining a new rate design as a "one size fits all" exercise.

2.3.1 CLD/HONI Members are Diverse in Terms of Customers and Facilities

CLD/HONI notes that although they comprise a small proportion of the distributors in Ontario, they serve roughly two-thirds of the province's customers within each class. Each CLD/HONI member has distinct characteristics as shown in the table below.

CLD/HONI Selected Statistics

	Enersource	Horizon Utilities	HONI	Ottawa	PowerStream	Toronto	Veridian
Substations	66	28	>1,000	90	54	163	52
DS transformers	>25,000	>24,000	>500,000	>45,000	>45,000	>60,000	>16,800
Km Distribution	5,000	>3,400	>120,000	>5,500	>6,000	>10,000	>1,400
# Res. customers	~180,000	>219,000	>1,100,000	>291,000	>316,000	>661,000	>107,000
# C&I customers	>22,000	>20,000	>112,000	>27,000	>36,000	>82,000	>9,900
System peak demand (MW)	1,350	944	3,770	1,307	1,677	4,273	445
% of C&I Customers consuming <50 kW	80	90	93	87	87	87	89
C&I customers as a % of peak demand	76	60	55	66	66	73	53
C&I Classes >50 kW	GS 50 – 499kW; GS 500 – 4,999kW; Large Use (>5,000kW)	GS 50 – 4,999kW; Large Use (>5,000kW); Large Use, dedicated assets	GS > 50 sub-trans-mission	GS 50 – 1,499kW; GS 1,500 – 4,999; Large Use (>5,000kW)	GS 50 – 4,999kW; Large Use (>5,000kW).	GS 50 – 999kW; GS 1,000 – 4,999 Large Use (>5,000kW)	GS 50 – 2,999kW; GS 3,000 – 4,999 Large Use (>5,000kW)

2.3.2 Implications of Our Customer Diversity

The C&I customers served by the companies that comprise CLD/HONI are not homogenous from company to company, or even within any single distributor, as illustrated by the data in the table above and the information provided in Appendix A.

Harder to identify are differences along the lines discussed in the Staff Paper at page 12 between traditional consumers, active consumers and prosumers. This categorization underlines the reality that while customers may appear very similar in terms of the usage and load profiles, they may have very different expectations from their local distributor. A

simple rate design may be very important to one customer, while for another the resulting lack of flexibility may be the motive to consider alternatives to utility service as they become available in the marketplace. In CLD/HONI's view, any standardized rate design will create winners and losers across different types of customers. As technological innovation gives rise to new, and currently unanticipated, options for consumers, the customers for whom the standardized design is not well suited will be the first to explore unregulated alternatives when they become available. While addressing this concern requires consideration of policies that are beyond the scope of the current process, CLD/HONI considers it to be an urgent priority to address the broader policies that are needed to enable distributors to be responsive to the wide range of consumers that we currently serve. If the regulatory framework is not adapted to facilitate the evolution of today's distributors to the distributor of the future, the Ontario electricity sector may be unprepared for the disruption that may occur as a result of unpredictable technological innovation.

A further implication of this diversity among distributors and their customers is that in the next phase of the process, it will be important for Board staff to undertake analysis along the lines of that provided in Appendix A of the Staff Paper for a larger sample of distributors. Analysis done based only on a few distributors may be misleading in terms of the impact of implementing the same changes across **all** Ontario distributors. As such, it will be essential to undertake LDC-specific analysis across a broad range of distributors for review and comment by stakeholders.

CLD/HONI notes that shifting of cost responsibility between customers may be most noticeable and drive significant customer impacts in rate classes with small numbers of customers. The result could be particularly damaging in cases where only some customers/industries within a class have the ability to shift their demand. This is important given that the average number of "Large User" customers is 2. While Hydro One and Toronto Hydro have fairly large numbers of Large Use customers, Horizon Utilities and Hydro Ottawa have 11, Enersource - 9, Brampton - 6, Enwin - 5, and most other utilities have 2 or 1.[6] The potential rate impact and cost shifting to classes with small numbers of customers can be either quite significant, or completely irrelevant for those distributors with only 1 customer in their Large Use class.

In addition, the wide range of daily and monthly load shapes among C&I customers, as shown in the material provided in Appendix A for generic customer types, illustrates the concern with shifting of cost recovery responsibility, and potential rate impacts for certain customer groups, as a result of some of the proposed rate design options.

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[6] See Ontario Energy Board Yearbook, 2014.

CLD/HONI is of the view that any change in rate design must be carefully considered and that there must be a sound basis for shifting costs amongst customers. To the extent that it is fair and reasonable to use rate design to transfer costs amongst customers, bill impacts may require mitigation strategies. This is an issue that is beyond the scope of the current phase, but is an important implication for any change that is implemented. The significance of these issues should be assessed through additional analytic work prior to the next phase of the C&I Rate Design Review.

3 GENERIC COMMENTS ON IDENTIFIED ISSUES

3.1 MONTHLY SERVICE CHARGE

The Staff Paper states at page 8: "Staff welcomes comments by stakeholders as to what measure should be used to set the fixed charge for each class (the Monthly Service Charge)".

The established reference value for defining an appropriate level for a distributor's monthly service charge is tied to the Peak Load Carrying Capability ("PLCC"). This approach was developed in an era when the rate design objectives that underpin the current rate design review were not considered. When the Board's cost allocation model and the determination of the PLCC were initially introduced, revenue instability due to self-generation and the potential for grid defection were not relevant. CLD/HONI notes that for residential customers the adoption of a fully fixed rate is tacit rejection of the PLCC concept as a basis for determining an appropriate level for the monthly service charge.

In the view of CLD/HONI, an approach that would be more consistent with the objectives of the C&I rate design review is to determine a minimum bill based on the charge that constitutes a reasonable minimum contribution to the fixed costs of the distribution system. Essentially, an appropriate minimum charge that must be paid by a customer, even if the connection is being maintained in a period when no power is consumed, should be determined by balancing the goal of ensuring every customer pays a proportional share of the costs that are fixed in the short run, as a maximum, and the charge that will minimize the risk of grid defection, as the minimum.

This appropriate minimum bill (or monthly service charge) for each customer class will be different for each distributor and may change over time. CLD/HONI believes that each distributor must be able to set the minimum bill at the appropriate level for its service territory.

In general, distributors should be establishing minimum bills that are significantly higher than their current monthly services charges. The primary concern of the Board should be to ensure that increases resulting from the introduction of a minimum bill that makes the current monthly service charge redundant are phased in so as to avoid excessive bill impacts for customers.

3.2 DISTRIBUTED ENERGY RESOURCES

The Staff Paper observes that:

> *Distributed energy resources (DER) are becoming more cost effective and increasing penetration. Customers with DER will impact the distribution system design and operation. DERs receive value from being connected to the distribution system. Their connection may result in additional costs. In turn, DER can provide value to the distribution system depending on the kinds of services they can offer, and when and where they can offer them. Rate design will need to balance these aspects.*[7]

The Staff Paper notes that the value of DER benefits are entirely dependent on location and the distributors ability to control them (page 34). CLD/HONI believe the materiality of the benefits is also a relevant consideration and that the benefits are in part dependent on the length/term and firmness of availability of the distribution-connected DER.

CLD/HONI concurs with the comments made in the Staff Paper, with the exception of the implied suggestion that the complex issues related to DER can be adequately addressed as part of a rate design solution. CLD/HONI does not believe that any distribution rate design method on its own can achieve the desired goal of facilitating the efficient use of DER within Ontario's integrated electricity system. The value of DER relates to the overall cost and cost-effectiveness of generation, transmission and distribution.

It is also important to distinguish between DER resources that constitute "behind-the-meter" generation (i.e., load displacement generation) and DER resources that sell energy into the electricity market. CLD/HONI notes that the Board's March 29, 2016 letter said that the issue of load displacement generation on distribution rate design was going to be examined as part of the C&I initiative, as distinct from the impact of load displacement on retail transmission service rates which will be separately addressed by the Board.

Behind-the-meter DER

The CLD/HONI submits that other than fully fixed rates, none of the rate design options being considered address the need for recovery of costs of distribution assets that are required to be in place for those times when behind-the-meter generation is not available. Eliminating standby charges, for those distributors that currently have them, without the introduction of gross load billing or another method of recovering these costs, would result in all other customers subsidizing the recovery of these costs.

Standby rates are particularly important since customers benefiting from having the right to access capacity are causing costs to be incurred on their behalf whether or not they use that capacity. At the same time, it may be preferable to have customers with

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[7] Ibid., page 3.

significant self-generation capacity contributing to the overall cost of the system rather than being totally disconnected.

If customers require backup capacity on a firm basis, which would require maintaining capacity for them on the same basis as other customers, it would be appropriate to bill for distribution services on the basis of gross load. However, since gross load billing would be a deterrent to new DER projects, it may be preferable to introduce low priority distribution services. This approach to differentiating levels of services and pricing is common in the natural gas sector.

The Staff Paper states at page 12: "*Staff invites comments on how any of the options will be affected by large amounts of net metering (behind-the-meter generation)*". The CLD notes that the potential for large amounts of net metering highlights the importance of moving from a fixed monthly charge based on the PLCC to a minimum charge that reflects the average customer's proportional share of distribution costs that are fixed in the short run and are not avoidable.

The CLD/HONI position on the potential benefits that DER, in the form of behind-the-meter generation, provide to a distributors' system is captured in the discussion below on electricity market DER.

Electricity Market DER

The penetration and impact of DER on utility operations will be very different for each LDC. Furthermore, within each distributor's service area the costs and benefits will not be uniform. Identical DER technologies may provide benefits in some locations while only imposing costs in other locations. It follows that the efficient integration of DER into the grid will not be achieved through offering standardized credits for connected DER. In some cases, even if a DER opportunity can be justified on the basis of its overall benefits for the integrated electrical system, the project may impose costs with no offsetting benefits for the distributor. Efficient utilization of the grid may require a fee for the connection to the distribution grid, with separate payments to the DER provider that are reflected in Ontario's generation or transmission costs.

These concerns suggest that it may be appropriate to undertake the valuation and payment for the DER "services" via contracts between the IESO and DER service providers, with separate arrangements with the distributor that can be tailored to recognize the specific situation of each DER in a manner that accurately reflects the net benefits or cost for the distributor.

If DER contracts are between distributors and their customers, at a minimum it may be appropriate to establish "standard" and "non-standard" contracts. Non-standard contracts would be used for additional services such as priority response when outage occurs,

some sort of bypass, alternative fuels, standby charges, etc. These services would be priced separately and on top of the standard contract.

As the Staff Paper also notes at page 34 in its discussion of DER "[t]he value of these benefits to distribution systems is entirely dependent on location and the distributor's ability to control them." The subsequent discussion in section G of the Staff Paper acknowledges that a credit may be appropriate for a variety of reasons (planning and operations are explicitly discussed). CLD/HONI agrees with the clear implication of this discussion that it would not be appropriate to develop a standardized DER credit. Rather, the best way to realize the promise of DER as a means of increasing the efficiency of the integrated power system in Ontario and to reduce the total cost borne by Ontario consumers will be to enable distributors to facilitate the development of economic DER.

Screening potential DER so that economic opportunities are enabled while uneconomic ones are not incented will require detailed case-by-case evaluation. CLD/HONI believes that distributors are in the best position to conduct these evaluations and to determine the location and type of distribution-connected DER that should qualify for credits or other means of enabling the value of DER to be captured by the DER providers. Only where the overall value to the system is recognized and captured by DER providers will economic DER be developed.

Screening of this type should also address situations where DER provides value to the customers or to the integrated electricity system but imposes costs on the distributor. CLD/HONI believes that distributors should have the ability to recover the costs from the customers that cause those costs. If the costs are socialized and recovered from all customers, the result would be that inefficient or uneconomic DER would be encouraged.

Enabling DER to capture the benefits it creates for the system overall can best be accomplished by introducing appropriate incentives for distributors to encourage economic DER and to enable them to develop credit or other mechanisms to encourage economic DER. This goal will require rate-setting flexibility. To the extent that DER provides overall system benefits, as distinct from distribution system benefits, any credits to reflect these benefits should be recovered on a Provincial basis thereby ensuring that local LDC customers are not paying for provincial benefits.

These methods of enabling the development of efficient DER are beyond the scope of the current rate design policy proceeding. The introduction of credits for DER will not be effective in the absence of a more fundamental policy approach to encouraging DER that benefits Ontario's integrated electricity system. CLD/HONI urges the Board to undertake a follow up process to address these issues in the very near future.

3.3 Achieving Revenue Neutrality in Light of Customer Response

An issue that is relevant to all of the options identified in the Staff Paper, although it is not explicitly identified, is the challenge associated with distributors appropriately forecasting the charge determinants associated with any of the new time-differentiated rate designs options given the uncertainty in predicting how customers will respond to the rate design price signals. This is of particular concern given that distributors will be responsible for developing a volumetric forecast for setting rates over their IRM terms (5 years or more) and currently there is no mechanism for incorporating changes to the forecast based on the actual customer response to rate design changes within the RRFE regime.

It is CLD/HONI's view that a mechanism will be required to adjust rates on a more frequent basis than is currently done to reflect the changes from customers adopting new behaviour as a result of the new rate designs. Some of the rate design options would place distributors at considerable revenue risk if adopted without also implementing a mechanism to mitigate the impact of unforeseen, disruptive customer responses. This concern is also referred to as the challenge of anticipating "2nd order effects", which include both the intended and the unintended consequences of rate design innovations. CLD/HONI notes that section C.4 of the Staff Paper recognizes that 5.7% of load shifted out of summer peak periods due to TOU commodity pricing. While the amount of load shifting that would occur in response to time–differentiated distribution pricing could realistically be expected to be less than for commodity TOU pricing, some amount of shifting should be anticipated. The impact of this shifting should be taken into account in developing distribution pricing options that promote shifting of demand. The more extreme the pricing proposal, the greater the need for understanding these 2nd order effects.

In terms of identifying where the 2nd order effects are likely to be most significant, CLD/HONI notes that for customers with high load factors, the delivery charges represent a low percentage of the bill and therefore 2nd order effects may be minimal. However, for customers with low load factor, the delivery charges represent a relatively higher percentage of the bill and therefore may trigger a greater response to peak pricing for distribution services.

CLD/HONI is particularly concerned with 2nd order effects on rate setting for intermediate and large user customer classes with relatively few customers since individual customer forecasts are critical to setting appropriate rates for those classes.

3.4 Testing Options with Pilot Projects

The Staff Paper does not explicitly raise as an issue the potential value of using pilot projects to gain insight into the market response and consumer acceptance of options that are considered to be attractive based on conceptual considerations. CLD/HONI sees

merit in testing the rate design options that are under consideration by implementing pilot projects in order to gain practical experience in the Ontario context.

CLD/HONI believes that the benefits of rate design pilot projects would include gaining insight into the potentially significant 2nd order effects that make it difficult to forecast the demand and related rate impacts that would result from implementation of any option that has non-trivial incentive effects. In order to gain a full understanding of consumer responses, it will be important to require all customers in the relevant customer class of a distributor to be part of the pilot project. If the only participants are customers that "choose" to participate in the pilot (e.g. prosumers), the resulting self-selection bias will not provide a good representation of the customer response that could be expected from the class as a whole. This will not allow an appropriate assessment of the rate impacts for the class and it may also not provide an adequate assessment of the implications to the distributor.

The downside of testing rate design options through pilot projects is that the time required to set up, run, and evaluate pilots would delay implementation of the new rate design. Consequently, there are advantages to relying on the experience of other jurisdictions when relevant information is available. However, decision-making based on other jurisdictions must recognize the very unique hybrid market we have in Ontario (e.g. distribution-specific rates, separate from commodity pricing and the incentive effects of the Global Adjustment), which may drive customers' responses in Ontario that are very different from the experience in other jurisdictions with integrated "all-in" electricity prices.

4 EVALUATION OF GS<50 RATE DESIGN OPTIONS

Table 2 at page 17 of the Staff Paper sets out four rate design options for the GS<50 class, reproduced below for convenience.

	GS< 50 kW Design Options
1	Fully fixed charge
2	TOU option • Fixed part based on OEB's Cost Allocation Model Minimum System with Peak Load Carrying Capability ("PLCC") adjustment • Variable part based on kWh in RPP on and off-peak time periods – will be the same across both winter and summer periods
3	Energy use blocks • Fixed part of contract peak kWh blocks that a customer will choose from and pay accordingly • High variable part that will apply if the customer goes over their self-selected demand threshold • There is no delivery charge for kWh used overnight and on weekends (off-peak)
4	Minimum bill: • Zero fixed charge • 100% variable rate with a minimum bill that represents the current use of 20% of customers

CLD/HONI notes that the current rate design for GS<50 customers of all distributors consists of a fixed monthly service charge and a variable kWh charge. However, there are significant differences in the fixed/variable splits in the rates that are currently approved for different distributors. As a result, the CLD/HONI anticipates that while the impact on customers of changing the GS<50 rate design could be manageable for the customers of some distributors, there could be significant bill impacts for others that would require some form of mitigation.

Since any change in rate design will involve bill impacts and changes to within-class cost responsibility that will be disruptive for some customers, it is anticipated that changes to the current rate design will be acceptable only if the resulting benefits justify the negative impacts that will be experienced by some customers.

4.1 FULLY FIXED CHARGE

The discussion below provides CLD/HONI's assessment based on the evaluation criteria set out in Section 2.1.

Some GS<50 customers place a high value on their costs being predictable. These types of customers may find a fully fixed charge very attractive, although the value of being able to establish a known monthly charge for the distribution portion of their electricity bills in the absence of greater certainty in their total bill may limit the appeal of this option.

The absence of any variable charge suggests that a fully fixed charge would be less supportive of customer choice and innovation for customers to manage demand with behind-the-meter generation. However, as the Board noted in its decision to adopt fully fixed charges for residential customers, the assurance of full cost recovery that comes with a move to fully-fixed charges will ensure that distributors do not have any disincentive to promote and facilitate innovation.

A fully fixed charge would convey the message that the cost of connection is essentially fixed in a simple and clear way. This may be an effective and suitable price signal for the traditional customers within the GS<50 class.

A fixed charge would stabilize distribution revenues with respect to changes in the demand for power within the GS<50 class. Under a fully fixed charge, the current LRAMVA would no longer be required to eliminate the variance in revenue resulting from customers achieving higher than forecast levels of CDM.

A fully-fixed charge would be easy to implement and reduce billing administration costs. However, the increase in distribution costs for a large majority of customers could drive increased customer service costs in addressing customer call volumes in the near term.

Customer acceptance of this rate design option will be determined primarily by the bill impacts. CLD/HONI notes that the Board staff analysis in Appendix A of the Staff Paper indicates that about 75% of customers in the GS<50 rate class would experience an increase in their bills if this option was adopted, and about 10% of customers would see distribution bill increases in excess of 400%. These are very large percentage impacts that would be extremely difficult to mitigate, although it is noted that in terms of absolute dollars, the total bill impact may be considered acceptable for commercial customers. The magnitude of the rate impacts reflects the fact that, as shown in the CLD/HONI data provided in Appendix A to this submission, there is a skew in consumption among customers in this class with a significant number of customers having very large consumption well above the average.

Unlike the residential class, a comparatively higher proportion of the costs "caused" by customers in the GS<50 class are demand-related. Consequently, since a fully fixed charge inherently ignores demand, it will be inequitable in that customers with high

demand will be cross-subsidized by those with lower demand. Since this cross-subsidization eliminates price signals related to demand, it undermines the alignment of customer with distributor interests and efficient use of the system. It may also be in conflict with the customers' perception of fairness based on electricity requirements.

A standardized fully fixed charge would necessarily reflect the individual distributor's fully allocated embedded costs. This concept of cost is not consistent with future-looking costs as indicated by the marginal cost which is the price signal that will be more appropriate as technological innovation introduces non-utility alternatives to traditional distribution services in the future. As such, active consumers and prosumers are likely to be least accepting of the change since it would preclude the ability to undertake actions to reduce their distribution charge short of disconnecting from the grid.

CLD/HONI is concerned that a fully-fixed charge that reflects embedded costs may provide a price signal that motivates uneconomic bypass by incenting GS<50 customers with low usage and low requirement for reliability to disconnect from the system, even though the marginal cost for the utility to maintain the connection would generally be very low. Distribution system efficiency would be harmed by uneconomic bypass if in the future new alternatives to grid power are less expensive than the total cost to consumers of the charges for power, the global adjustment and transmission when added to the fixed distribution charge.

The absence of any variable charge implies that distributors could face increased capacity costs with no offsetting revenue for higher usage levels. To the extent that customer demand drives investment in either increasing the capacity of the distribution system or investing in facilities and programs (e.g. smart grid) that allow the distributor to manage total demand so as to avoid capacity upgrades, these costs should be reflected in variable charges. This cannot be done under a fully fixed distribution charge.

4.1.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the Fully Fixed Charge option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** A fully fixed charge would not directly motivate customer actions that support innovation; however, the option would remove a disincentive to distributors striving to achieve maximum conservation by their customers, and would eliminate the need for an LRAMVA.
2. **Incentive for Efficiency:** This option does not provide a price signal to encourage greater efficiency in the utilization of the distribution system. Distribution system efficiency could be harmed through uneconomic bypass if new alternatives to grid power become less expensive than the total cost to consumers of the charges for power, the global adjustment and the fixed distribution charge.

3. **Financial Prudence:** A fully fixed charge would stabilize distribution revenues with respect to changes in the demand for power within the GS<50 class, but could increase the financial risk associated with grid defection in the future.
4. **Cost transparency:** A fully fixed charge reflects the essentially fixed nature of distribution costs.
5. **Equity:** To the extent that per customer costs do not vary with consumption, a fully fixed charge is equitable. The concept of cost of connection reflecting all costs is, however, an oversimplification that loses validity for larger customers in the GS<50 class.
6. **Practicality:** Customer acceptance of this change will be determined primarily by the bill impacts, which could be quite large for some customers in percentage terms, but may be reasonable in terms of absolute dollar impacts. This option improves rate stability for customers.

4.2 TIME OF USE ("TOU") DISTRIBUTION RATE

A time of use distribution charge based on energy use (kWh) will provide an incremental incentive to reduce peak period energy use. This option should therefore be directionally supportive of increased efficiency in the use of the distribution system. Nevertheless, CLD/HONI is concerned that this approach does not actually capture that the cost driver that is relevant for aligning the interests of customers and distributors is demand. Charging for distribution services on this basis is simply charging customers on the basis of their average demand during the peak period, rather than on the basis of their actual coincident peak or non-coincident peak demand.

Furthermore, while the directional effect of the incentive is reasonably clear, it is far from clear that the magnitude is sufficient to influence the behaviour of many customers. The distribution portion of the typical GS<50 customer typically represents less than 25% of the total bill, therefore the main driver for customers will be what they can do to reduce the commodity portion of their bill. Customers that have not shifted demand in response to commodity price signals (perhaps because their type of business does not permit it) are not likely to be incented by a modest ***incremental*** incentive provided by the distribution rate.

CLD/HONI notes that the Staff Paper is silent on the factors being applied to differentiate between on-peak vs off-peak rates. There is no information on the rationale used for setting those relative prices. It would be very difficult to establish TOU rates that appropriately reflect the actual marginal cost associated with increasing capacity for each distributor. It would be even more intractable to establish rates that reflect the different loading on different portions of the distribution system. Charging rates that discourage consistent use of facilities with no risk of becoming overloaded would not enhance the efficiency of utilization of the distribution system.

For this reason, the impact on facilitating investment planning is unclear, since the impact would be uneven across a distributor's system. The impact may be hard to predict on a locational basis for feeders with peaks that do not correspond to on-peak periods for the system being negatively impacted.

To the extent that adding TOU charges for distribution to the TOU energy charges for power does result in an increased customer response, the second order effects on distribution revenue (i.e., the customer response to the price signal) would be difficult to forecast. Consequently, if, contrary to the expectations of CLD/HONI, this option motivates customers to modify their power usage significantly, distribution revenues will become less stable. The instability would correspond to the degree of price elasticity in the GS<50 demand for electricity in peak periods. If the TOU distribution rate option is adopted as a general conservation initiative, it would be appropriate to include its impact in the LRAMVA in order to hold distributors whole and stabilize distribution revenues.

This option will also make distribution rates less stable for customers as rates would have to change as a result of customers shifting their on peak consumption in response to changing TOU commodity prices.

CLD/HONI notes that most distributors would have to incur significant costs to make the necessary adaptations to their current billing systems. It would be desirable to allow distributors to defer implementation of this approach if their system cannot be easily adapted. The complexity of the billing system changes will be more prevalent if the time periods used for the TOU distribution rates do not match the mandated TOU periods for commodity. These differences would also make the billing regime less understandable for customers. This option could also potentially increase the length and complexity of customer bills if bill presentment modifications were required to communicate the desired distribution price signals. Furthermore, given that customer demand in the GS<50 class is largely inelastic, the addition of time-differentiated distribution rates may also increase customer frustration with respect to their overall ability to control their energy costs.

4.2.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the Time of Use Distribution Rate option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** Conceptually, this option is consistent with enabling customers to leverage new technologies that reduce their demand and bills. However, customers that are responsive to price signals are most likely to act in response to commodity TOU rates; leaving little incremental benefit for TOU distribution rates.
2. **Incentive for Efficiency:** A TOU distribution charge is an imperfect proxy for demand as the driver for distribution costs. The demand peaks on individual feeders may occur outside the system peak hours as defined for TOU purposes. Hence, while the TOU

option may increase efficiency in parts of the system that are capacity constrained, it could result in inefficient overloading on other parts of the distribution system.

3. **Financial Prudence:** In the absence of a modified LRAMVA that takes into account the impact on revenue of TOU distribution rates, the difficulty in forecasting the customer response to changes to the distribution rate design option would increase the risk of unforeseen lost revenue.
   Customer response to changes in TOU commodity rates will also have uncontrollable and unpredictable impacts on distributor revenues when customers shift their load from peak to off-peak periods.
4. **Cost transparency:** Most distribution system costs do not vary with TOU and the distribution system of most distributors is not capacity constrained at this time. Consequently, TOU pricing would not be reflective of distribution cost drivers.
5. **Equity:** TOU rates are only equitable where costs are driven largely by peak period demand. In most cases, TOU rates would tend to overstate the impact of peak -period demand on distribution costs.
6. **Practicality:** This option would be likely to compromise rate and bill stability for customers because of the need for more frequent rate change in response to customer actions to shift their on-peak load, not only due to the TOU distribution pricing, but also in response to TOU commodity pricing changes. Distributors would also experience material impacts associated with implementing changes into their billing systems.

4.3 PEAK ENERGY USAGE BLOCKS

Implementing a distribution charge along the lines of peak energy usage blocks as described in the Staff Paper would create incentives for customers to manage their demand so as to stay within the selected block. This approach should create a relatively strong incentive at the threshold between usage blocks, but weaker incentives, similar to a fixed charge if use does not approach the threshold. It is therefore likely that some customers will be motivated to implement technologies that enable them to shift demand between time periods. As storage becomes more economic, for example, implementing storage could become an easy way to reduce consumption at the end of the designated periods and shift that demand (recharging storage to the subsequent period).

Unfortunately, the customer response within a time period may not be consistent with reducing peak demand when it results in cost reductions for the distributor unless the usage period for customers is diversified. Individual customers could end up trimming demand late in their usage period if they are approaching the threshold. If they are using storage to limit demand, usage could rebound at the beginning of the next period. While these types of tactics may encourage innovation, the techniques used may not be efficient

either from the perspective of the distributor or in terms of total costs (system plus customer). The unintended consequences could be counter-productive.

The response of customers to this option may be very sensitive to the design details, such as the number of blocks and the price differentials between blocks. In order to ensure that most customers have a meaningful incentive to reduce their consumption, it will be desirable to have a large number of relatively narrow blocks, otherwise few customers will be close enough to a threshold to pursue conservation.

However, the larger the number of blocks, the less the incentive to avoid moving to a higher block and the greater the amount of churn as customers move between blocks that distributors will have to administer.

CLD/HONI believes that most GS<50 customers are, and will continue to be, traditional customers, not active customers or prosumers. These traditional customers are unlikely to be enthusiastic about managing their demand to stay within a defined energy usage block. Some traditional customers may therefore simply choose a block based on past usage and make no attempt to modify their use of power. Financially challenged businesses may be tempted to opt for a small, cheaper block and find that it is harder to control their consumption than anticipated. In the cell phone model, most customers have exclusive control of their usage. For GS<50 customers, there will generally be a number of individuals (e.g., employees and clients) that affect total usage. This market reality could be a prescription for customer annoyance when there are overage charges. Even if the account holder is advised when the limit is being approached, it may be hard to keep total usage within the selected block. CLD/HONI is concerned that the practical reality of this option may be far inferior to the conceptual ideal.

CLD/HONI is concerned that the second order effects associated with the response of customers to the introduction of this option will be very challenging to predict, especially in the initial years. For example, to smooth the end-of-period effects, the customer response should be diversified by diversifying the billing cycles of customers. Unfortunately, the strategies needed to maximize the efficiency benefits would increase the complexity of the methodology for customers, making it less understandable and less acceptable to customers.

Under this option, customers would only have to contract and pay for on-peak usage, which raises a concern that this would provide a “free-ride” on distribution costs for customers who are able to shift (or have already shifted in response to commodity pricing) a significant portion of their load to the off-peak period. Providing such a significant incentive tied only to peak period usage may be justified for distribution systems that are heavily capacity constrained, but that is not the case for most Ontario distributors. This option essentially values off-peak distribution service at $0 and the CLD/HONI submit that there are costs associated with running the distribution system even during the off-peak

periods, and therefore an option that charges just for on-peak usage is inappropriate in that it provides no incentive to manage consumption during the off peak period.

CLD/HONI notes that the first block would constitute a minimum bill. It would therefore be important to ensure that the charge for the first block (minimum bill) reflects the minimum cost of connection and is consistent with full cost recovery for the distributor. The increasing charge for larger blocks should be designed to provide a meaningful price signal – that is the long run marginal cost of capacity. If the tiered pricing is not properly designed, it could result in higher usage customers subsidizing customers with lower use, regardless of the drivers of higher demand.

From the distributors' perspective, this option would introduce significant practical complexity to implement that could undermine the conceptual simplicity of it for both the customer and distributor. In particular, the work required to annually check and potentially update customer contract amounts is anticipated to significantly increase administration costs. In addition, as the Staff Paper suggests, it may be important from a customer-focused perspective, to implement early warning systems that advise consumers early in the period if they risk exceeding their selected block. Appropriate systems are likely to be onerous and expensive for distributors to implement and maintain. Even if automated, these early warning systems are almost certain to lead to increased customer inquiries/ complaints about their bills, especially if the overage charges are significant enough to be a serious disincentive to exceed the selected block. Perceived equity will be a challenge.

A potential variant of this option that would significantly reduce the complexity for customers would be tiered or "progressive" rate structure as opposed to a self-selected Energy Usage Block design. Under this variant, the variable portion of the tariff would be divided into a number of consumption blocks and each subsequent block has a higher block price. Customers would not need to pre-select the usage block. This approach would mitigate the effect of rate increases on lower consumption customers and ensure that basic uses of electricity remained affordable for all customers. It would encourage conservation, efficiency, and self-generation by sending a price signal to high users. Elimination of the "self-selection" option would remove the most serious implementation issues for customers and distributors, but would still represent a significant change to the current billing system that would drive material implementation costs.

4.3.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the Energy Usage Blocks option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** A steep cost increase at block thresholds should provide an incentive for innovation, but that incentive is likely to be uneven and poorly correlated with the avoidance of peak demand on constrained portions of a distributors system.

2. **Incentive for Efficiency:** The actions taken by customers to reduce their bills are unlikely to correlate with increasing the efficient utilization of the distribution system.
3. **Financial Prudence:** Once established, this approach should result in more predictable demand and hence more stable revenue. It is essentially a fixed charge, scaled to the tier of demand of the individual customer.
4. **Cost transparency:** This option does not reflect the driver of distribution costs.
5. **Equity:** This approach may reflect the perception of some customers that equity is achieved by charging those with high use a higher amount for distribution service. However, it would enable customers with historically low peak usage to benefit even if they do not respond to the distribution pricing incentives.
6. **Practicality:** This option would involve major implementation complexity and administrative burden with establishing, and annually reconfirming, the customers contracted block. There would also be complexities associated with potentially adopting an early warning system when customers approach their contracted peak usage.

4.4 Minimum Bill (kWh)

As the Staff Paper states: “This option is really a variation on any rates design.” CLD/HONI agrees with this observation.

Page 21 of the Staff Paper invites stakeholders to comment on “preferences for the underlying rate design” of the minimum bill approach. CLD/HONI has the following generic comments that apply to the use of the minimum bill concept for any rate class and in conjunction with any rate design.

- A fully fixed rate is a form of minimum bill. This concept has already been adopted by the OEB for the residential class and mentioned separately as an option in this policy review.
- The key to minimum bills is to set the minimum at a level that ensures the utility a consistent level of appropriate revenue, while not penalizing the vast majority of customers, or inhibiting efficiency. A minimum bill ensures that the distribution utility receives sufficient revenue from each customer and it guarantees that every customer contributes at least a minimum amount toward the utility revenue requirement. This would help minimize the impact on other customers with limited options from getting an inappropriate amount of costs transferred from those who can shift usage/demand and other initiatives such as a net metering.
- The minimum bill should be based on a “significant” portion of consumption i.e. tied to 25% (or more) percentile of customer consumption to reflect significant costs that are unrelated to consumption.

The CLD/HONI anticipate that under the Minimum Bill option, a revenue neutral rate design would result in a higher kWh charge, where the energy corresponding to the minimum bill would not incur a charge, while usage above that minimum would incur a charge that is higher than the current kWh rate. This change should be implemented on a distributor-specific basis in a manner that minimizes customer disruption while increasing the kWh component to a level that improves the efficiency of the customers' use of the distribution system.

The actual implications of the minimum bill approach would depend on the level of the minimum charge. Unless it differs significantly from the existing monthly charge, there would be little difference from the status quo.

4.4.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the Minimum Bill option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** Conceptually, this option should encourage innovation; however, for customers with high consumption/demand, CLD/HONI doubts that the incentive effects of the distribution rate will be significant, particularly for customers for whom distribution costs may represent a small percentage of their total bill. To the extent that innovation occurs in the industry, it will be driven primarily by the cost of the commodity and the Global Adjustment.
2. **Incentive for Efficiency:** This option should provide an incentive to utilize the distribution grid efficiently. However, those incentives may not have any value depending on the extent to which a distributors' system is constrained. Additionally, in practice, any distribution pricing incentive effects are likely to pale relative to the response to commodity pricing and the Global Adjustment.
3. **Financial Prudence:** The Minimum Bill option could stabilize distribution revenues as a result of an increase in the fixed portion of the distribution amounts charged. However, this option could increase the financial risk associated with the volumetric charges to customers due to the volumetric rate being set higher than the current rate. The financial position of distributors could be harmed if, contrary to the expectations of CLD/HONI, there is a significant response to the introduction of this option, and there is no mechanism introduced in parallel to address the impact of lost revenues.
4. **Cost transparency:** A Minimum Bill amount set at a rate higher than the current fixed charge could more appropriately reflect a higher portion of the fixed costs associated with servicing customers currently. A higher volumetric rate would act as a deterrent to customers to increase consumption or demand thereby mitigating the need for future investment.
5. **Equity:** A minimum bill ensures that every customer contributes at least a minimum amount toward the utility revenue requirement.

6. **Practicality:** Customer acceptance of this change will be determined primarily by the bill impacts, which could be quite reasonable depending on the design of the minimum bill. This option improves rate stability for customers.

4.5 DEMAND BASED RATES FOR GS<50 KW

Page 17 of the Staff Paper invites comments on "whether consideration should be given for demand based rates for the GS<50kW class." CLD/HONI considers this option to be conceptually preferable to the energy based options. However, it is recognized that it is not a practical option at this time since many current GS<50 customer meters do not allow for demand based billing. CLD/HONI considers the cost of replacing these meters to enable demand billing could not be justified since there would be little savings in terms of avoided costs as a result of reduced distribution system demand.

4.6 CLD/HONI RECOMMENDATION: GS<50 CLASS

CLD/HONI is not in favour of the Peak Energy Block or the TOU options proposed since there would be little correlation between the incentive for customers to reduce or shift their demand and the opportunity to avoid future costs by reducing peak demand on constrained portions of the distributor's facilities. These options are not superior to the current kWh-based charge in terms of any of the criteria used by the CLD for this evaluation.

CLD/HONI is of the view that a fully fixed charge is attractive, but practical implementation of the concept would require some recognition of the different levels of value placed on connection to the distribution system by different customers. Many of the smaller GS<50 customers of most LDCs are almost indistinguishable from residential customers, while many of the largest GS<50 customers will respond to price signals in a way that is more like GS>50 customers. The fully fixed charge option would be enhanced by giving distributors the opportunity to revise their customer classifications in combination with introducing fully fixed charges that are deemed appropriate for the revised customer classes.

In the absence of revisions to the existing customer classifications, CLD/HONI believes that a closely related approach would be to replace the current fixed monthly charge that is largely based on the PLCC as determined by the cost allocation model with a minimum charge that is determined by each LDC based on its circumstances. Considerations would include the makeup of the customer base and the current level of the monthly customer charge. Distributors that determine that it would be acceptable to increase the minimum charge to a level that would be revenue neutral in the absence of a variable kWh charge could choose to adopt a fully fixed charge.

5 EVALUATION OF GS>50, INTERMEDIATE AND LARGE USE OPTIONS

Table 3 at page 22 of the Staff Paper sets out the rate design options for the GS>50 class, reproduced below for convenience.

The options considered by Board staff are essentially the same for the GS>50, Intermediate and Large Use classes. The one exception is the inclusion of the Minimum

	GS > 50 kW Design Option
4	Minimum bill: • Zero fixed charge • 100% variable rate with a minimum bill that represents 20% of customers
5a	Three part demand rate • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand at any time • Peak is 7 am to 7 pm
5b	As 5a • Peak is 3pm to 9 pm
6a	Time of Use • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand during the off-peak period • Peak is 7 am to 7 pm
6b	As 6a • Variable 2 is 0

Bill option only for the GS>50 class, although CLD/HONI believes that a minimum bill feature could also be implemented for the Intermediate and Large Use classes as well.

The sections below contain a generic evaluation of each option for the three larger volume classes using the identified evaluation criteria. Any class specific exceptions are noted in the discussion.

The CLD/HONI notes that the current rate design for GS>50, Intermediate and Large Use customers consists of a fixed monthly service charge and a variable kW charge. However, as is the case with GS<50 customers, there are significant differences in the fixed/variable splits in the GS >50 rates that are currently approved for different distributors. As a result, the CLD/HONI anticipates that while the impact of changing the GS>50, Intermediate, and Large Use rate design could be minimal for the customers of some distributors, there could be significant bill impacts for others.

From a distributor perspective, the costs associated with implementing and maintaining either of the proposed Three Part Demand or TOU Demand rate design options could be significant. Changes to meter reading and billing systems may be required, and would likely be costly.

Any change in rate design will involve bill impacts and changes to within-class cost responsibility that will be disruptive for some customers. As such, any change to the current rate design will be acceptable only if the resulting benefits justify the negative impacts that will be experienced by some customers.

The Staff Paper notes that bill stability is important for the GS<50 class customers (page 10). Bill stability is important for many large customers as well, many of which operate on pre-set operating budgets that offer limited flexibility in the short-run.

5.1 THREE PART DEMAND RATE

Since a three part demand rate would introduce an on-peak demand charge, it would increase the incentive to reduce peak demand through either conservation or self-generation during the on-peak hours.

However, reducing the coincident demand of customers in the larger volume classes will increase distribution efficiency only if these customers are using heavily loaded feeders. Distributors experiencing steady growth are likely to benefit from this incentive; whereas distributors serving areas with little growth or declining demand will not benefit from further load reductions. Furthermore, CLD/HONI notes that for the distribution system, the relevant economic costs are those associated with station peaks, not the LDC's system peak or the transmission peak.

In effect, this rate design may primarily reward GS>50 customers for actions they have taken, or will take, in any case to manage their commodity costs. Even more critically, some customers will experience decreases in the distribution portion of their bill simply as a function of how they have historically consumed electricity, and so some customers will be rewarded with lower distribution bills without having taken any action to specifically change their behaviour to use the distribution system more efficiently (free riders).

The Board Staff methodology applies a "factor" that establishes a differential between the peak and non-peak rate, but it is not clear what rationale Board staff have applied to determine that differential, or how it is linked to marginal or embedded costs. It will be important to understand the bill impacts for customers as a result of adopting different possible approaches to determining the differential.

The CLD/HONI would be concerned if an approach is adopted that turns out to do little more than shift costs among customers without system benefits.

A Three Part Demand rate is not expected to stabilize distribution revenues. The distribution revenue recovery risk that this rate design option entails would be accentuated by the magnitude of the differential between peak and non-peak anytime demand rates, and the response of customers to that differential.

The TOU demand charge option may result in significant bill impacts for some customers and can be expected to decrease the stability of rates for all customers in the GS>50 classes. Since the largest customers will tend to be the earliest adopters of new innovative technologies, including opportunities that involve disconnecting from the grid, they will realize the earliest and greatest benefits. The result will be cost shifting to other, lower volume customers within each class. Further analysis is required to determine the likely impact of a Three Part Demand rate on the equitable recovery of costs from customers within each class, taking into account the second order effects that result from the potential response of customers to the initial rate design change. Anticipating the impact over the longer term will be complicated due to the unknowns associated with future technological innovation.

CLD/HONI also notes that the OEB Yearbook shows that the Large Use classes of most distributors contain a very small number of customers (typically 2). The problems noted in the paragraph above could be particularly severe for Large Use classes as it may severely penalize one customer at the expense of the other. This will not be perceived as fair, and could be harmful for those industries or users who have limited ability to shift their load (e.g. hospitals, schools, certain businesses and industries).

The question is asked on page 25 of the Staff Paper whether peak demands should be measured based on simple monthly peaks, or some annual (or ratcheted) peak. While the ratchet may involve more maintenance for billing (i.e., keeping track of and adjusting the amount), it is the better option from the perspective of cost causation, and of price signaling.

CLD/HONI is even more concerned about the inequities that would result from adopting a "narrow peak" variant of this option. The benefit to customers of this option are likely to be enjoyed primarily on a fortuitous basis, and any response would generate little if any benefits in terms of reduced distribution costs except in very specific cases where overloading is forcing a system expansion that could be deferred or avoided. Essentially,

the narrow option would simply magnify the general concerns about this rate design option. Significant additional analysis of bill impacts would be very important before giving serious consideration to this variant of the option.

5.1.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the Three Part Demand Rate option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** Conceptually, this option should encourage innovation; however, in practice, CLD/HONI doubts that the incentive effects of the distribution rate will be significant, particularly for large customers for whom distribution costs may represent less than 5% of their total bill. To the extent that innovation occurs in this sector of the industry, it will be driven primarily by the cost of the commodity and the Global Adjustment.
2. **Incentive for Efficiency:** As with innovation, conceptually this option should provide an incentive to utilize the distribution grid efficiently. However, those incentives may not have any value depending on the extent to which a distributors' system is constrained.
3. **Financial Prudence:** The financial position of distributors could be harmed if, contrary to the expectations of CLD/HONI, there is significant load shifting in response to the introduction of this option, and there is no mechanism introduced in parallel to address the impact of lost revenues.
4. **Cost transparency:** Since the incidence and timing of capacity constraints is highly variable across distributors and for different portions of each distributors system, the Three Part Demand Rate would not be strongly indicative of the cost drivers of individual distributors.
5. **Equity:** This option is likely to have inequitable bill impacts across customers since the incidence of benefits is likely to result primarily from fortuitous circumstances – primarily due to the nature of the customer's business requirements - rather than deliberate actions undertaken by customers that have a positive impact on the distributors costs.
6. **Practicality:** Distributors are likely to face modest to significant challenges in implementing this option; however, the most serious concern of CLD/HONI is that customer acceptance of this option will be low given the magnitude of bill impacts and the decrease in rate stability.

5.2 TIME OF USE DEMAND

The Time of Use Demand option is very similar to the Three Part Demand Rate, except that the Variable 2 rate is based on the maximum demand in the off-peak period rather than the peak demand at any time as is the case for the Three Part Demand Rate.

CLD/HONI does not consider the impacts of the Time of Use Demand option to be noticeably different from the Three Part Demand Rate with respect to concerns associated with a differential peak period charge (a notable exception is the "free" off peak rate, discussed below). The major difference is that there will be a greater incentive to manage the off-peak period peak and the incentive to manage the on-peak period peak demand will be slightly greater. However, unless the response to these incentives are greater than CLD/HONI expects, because of the small impact distribution charges have on the total bill of these customer, the benefits in terms of the innovation and distribution system efficiency will be quite modest. Generally, the comments made in the preceding section apply equally to the TOU Demand charge.

In particular, a standardized rate will not recognize the future-oriented marginal cost differences between congested feeders and underutilized feeders. Different distributors and different segments of many distributors' systems will be characterized by very different marginal costs.

The TOU demand charge is not an option that can be expected to stabilize distribution revenues relative to the status quo. The distribution revenue recovery risk that this rate design option entails is accentuated by the difficulty in anticipating how customers will respond over time to the introduction of TOU demand charges, particularly as innovate supply options enter the market in competition with grid-based supply.

Most notably, the variant of this option that sets off-peak demand at a $0 rate is rejected by CLD/HONI. Aside from the potential for significant negative distribution revenue impacts as noted by Staff, CLD/HONI submit that there are costs associated with running the distribution system even during the off-peak periods, and therefore a zero rate for this period is unacceptable.

As with the Three Part Demand option, the TOU demand charge option may result in significant bill impacts for some customers and can be expected to decrease the stability of rates for all customers in the GS>50 classes, particularly for Large Use classes with small numbers of customers, and as a result of early adopters shifting their demands.

5.2.1 SUMMARY OF EVALUATION

CLD/HONI's evaluation of the TOU Demand option with respect to each evaluation criterion can be summarized as follows:

1. **Innovation:** Conceptually, this option should encourage innovation; however, in practice, CLD/HONI doubts that the incentive effects of the distribution rate will be significant, particularly for large customers for whom distribution costs may represent less than 5% of their bill.
2. **Incentive for Efficiency:** As with innovation, conceptually this option should provide an incentive to utilize the distribution grid efficiently. However, those incentives may not have any value depending on the extent to which a distributors' system is constrained. Additionally, in practice, distribution rate incentive effects are likely to pale relative to the response to commodity pricing and the Global Adjustment.
3. **Financial Prudence:** The financial position of distributors could be seriously harmed if, contrary to the expectations of CLD/HONI, there is significant load shifting in response to the introduction of this option, and there is no mechanism introduced in parallel to address the impact of lost revenues. The option of zero rate in off peak could be potentially destabilizing for revenues.
4. **Cost transparency:** Since the incidence and timing of capacity constraints is highly variable across distributors and for different portions of each distributors system, the TOU Demand option would not be strongly indicative of the cost drivers of distributors.
5. **Equity:** This option is likely to have inequitable bill impacts across customers since the incidence of benefits is likely to result primarily from fortuitous circumstances rather than deliberate actions undertaken by customers that have a positive impact on the distributor's costs.
6. **Practicality:** Distributors are likely to face modest to significant challenges in implementing this option; however, the most serious concern of CLD/HONI is that customer acceptance of this option will be low given the magnitude of bill impacts and the decrease in rate stability.

5.3 MINIMUM BILL (KW)

The Staff Paper identifies the minimum bill option only for the GS>50 class. The CLD/HONI believe that the arguments made in the section on the minimum bill option for the GS<50 class also apply to the GS>50 class, and the minimum bill concept could be layered on to the two time differentiated GS >50 rate design options.

CLD/HONI notes that every distributor is unique and the makeup of their Intermediate and Large Use classes is particularly variable across distributors. For this reason, CLD/HONI suggests that while the introduction of a minimum bill for Intermediate and Large Use customers should not be mandatory, it should be permitted in cases where a distributor can demonstrate that the minimum bill will be beneficial to both the company and its customers.

Furthermore, CLD/HONI notes that in the power market of the future, it will become increasingly important for distributors to be able to price connections for their larger

customers in a manner that reflects the value of grid connection to those customers and the marginal cost of providing that connection. Customers, distributors and Ontario's integrated electrical system will all benefit from pricing strategies that avoid uneconomic bypass and encourage customers to retain their connections to the grid. Having access to electricity through the distribution system is valuable to most customers even if it is rarely required. Certainly, maintaining customer connections that contribute margin to cover a distributor's fixed costs is far better than pricing in a way that encourages disconnection which may result in physical and financial stranding of assets.

If a minimum bill for Intermediate and Large Use classes is viewed as a reservation price, it may be appropriate. In this context, distributors should be permitted to determine on a case by case basis the economic price to adopt as a monthly charge (minimum bill) for their larger customers to retain their connection.

5.4 CLD/HONI RECOMMENDATION: GS>50 CLASS

CLD/HONI notes that unlike the GS<50 rate design, the current rate design for the larger customers already reflects the actual cost drivers for distribution services; customer-related costs and demand-related costs. As with GS<50 customers, CLD/HONI notes that peak loading on the facilities serving the larger customers does not consistently coincide with any standardized definition of on-peak and off-peak periods that could be adopted by the Board. It is this variability in load profiles that is addressed by the current rate design, which involves a charge for peak usage whenever it occurs. For this reason, CLD/HONI believes that the benefit of introducing TOU demand billing in terms of encouraging innovation and enhancing the efficiency of distribution system utilization is likely to be minimal. Furthermore, if the TOU time periods for distribution differ from the system peak periods used for the commodity, which would be appropriate from the perspective of reflecting utilization of each distributors system, there would be more confusion than motivation.

CLD/HONI do not anticipate that a move to time differentiated rates based on and off-peak demand will drive most of these larger users to alter their use patterns. The distribution portion of the bill of most GS>50 customers is typically between 10-20% of the total bill. For intermediate and large use customers, the distribution portion of their bills is often less than 10% of their total bill. Their electricity use decisions will be made primarily in response to the commodity and Global Adjustment portions of their bills, not in response to "drivers" of incentives on the distribution portion of their bills.

In cases of distributors with large customers that do respond to the incentives of an alternate rate design, it will be extremely difficult to anticipate the responses of a few large customers, and so the distributor's revenue requirement would likely be under-recovered. As a result, it will be important to implement an LRAM or comparable measure for

addressing the problem of lost revenues within the context of the Board's current incentive regulation regime.

CLD/HONI therefore urge caution in introducing a different approach to rate design for these larger volume customers. It is not clear that any of the rate design options under consideration would result in benefits that would justify the negative consequences identified with these options.

In summary, CLD/HONI does not recommend that the Board adopt either the Three Part Demand Rate or Time of Use options for GS>50, Intermediate or Large Use customers. The benefit of either of the two time-differentiated rate design options as compared to the existing any time demand charge is minimal and may cause load shifting that has no efficiency benefit for the distribution system. If this approach is adopted, distributors should have flexibility both in setting the price differential between peak and off-peak rates as well as in establishing on peak periods that are relevant given each distributor's specific circumstances. For example, the narrow peak mentioned as option 5b in the Staff Paper may enhance efficiency for some distributors.

In order to increase the generic incentive to reduce peak demand whenever it occurs, which would be relevant in the case of the GS>50 class, the CLD/HONI recommends that the current peak kW billing determinant be maintained but that the minimum bill concept could be implemented so as to increase the kW charge for customers that exceed the minimum bill threshold.

6 CONCLUSIONS AND RECOMMENDATIONS

Two key consideration in CLD/HONI's assessment of the C&I rate design options are:

- distribution rates, however designed, will be only a secondary driver of the energy use behaviour of C&I customers since distribution represents a small portion of the total bill; and
- the number and type of C&I customers varies dramatically across distributors, with the total number of customers in some classes being so small (typically two or fewer customers in most LDCs Large Use class) that the distribution bill impacts on other customers caused by any actions of individual customers will be significant enough to raise concerns about real and perceived equity among customers within the larger volume classes.

Any proposed changes must be fully analysed in more detail than currently contained in the Staff Paper and any resulting changes carefully managed to avoid harmful impacts to both customers and distributors.

The analysis of customer impacts that has been undertaken to date provides insufficient insight into the impacts of implementing the identified rate design options and is not sufficient to anticipate the extent of the consequences that could result from the proposed rate designs. It is extremely important that in the next phase of the process, Board staff undertake more detailed analysis along the lines of that provided in Appendix A of the Staff Paper for a broader sample of distributors

CLD/HONI anticipates that LDC specific analysis will demonstrate that the industry's diversity should be matched by rate design flexibility that allows each distributor to tailor their rate design to the specific needs of their customers and the makeup of their customer classes.

With respect to the design options for the GS<50kW class, CLD/HONI would prefer an option which allows for a variable rate component, together with an increased minimum fixed rate to be determined by each distributor, with the option for a fully fixed rate if customer impacts are considered reasonable. This option leverages the attractiveness of the fully fixed rate while recognizing that the GS<50kW class is less homogeneous in level of consumption than the Residential class.

Conceptually, CLD/HONI believes that the pros and cons of the options identified for the GS>50, Intermediate and Large Use classes, all of which are currently billed on a fixed charge plus anytime demand rate basis, are very similar for all classes. The most important difference is that the Intermediate and Large Use classes typically have a small number of customers, often only one or two per distributor.

The two basic options identified in the Staff Paper for each of these three classes are the Three Part Demand Rate and Time of Use Demand**.** While CLD/HONI sees some merit to both of these options, CLD/HONI does not endorse either option as we consider the benefits, which are likely minimal, to be outweighed by the costs. GS>50 customers are more responsive to peak commodity and Global Adjustment charges than distribution charges.

CLD/HONI also believes that it would be appropriate for distributors to have the option of introducing a minimum bill for customers in each of the larger volume classes. It may serve as an important option for dealing with situations where customers wish to maintain their distribution connection despite meeting most of their requirements, most of the time, through self-generated supply.

Under any new rate design, the customer response and revenue impacts will be difficult to forecast resulting in potentially significant revenue impacts for distributors. Distributors therefore may not have a reasonable opportunity to recover their costs under the current Board incentive regulation regime unless some version of a lost revenue adjustment mechanism, or some comparable measure, is implemented to address large unanticipated variances from forecast.

OEB Staff's paper indicates that one of the goals of new rate design is to "avoid the need for specialized rate classes for load displacement generation and net metered customers and charges like standby rates".

CLD/HONI believes that any option other than fully fixed rates will not address the need for recovery of costs of distribution assets that are required to be in place for those times when generation behind the meter is not available. Eliminating the standby charge without the introduction of gross load billing or another method of recovering these costs, would result in all other customers subsidizing the recovery of these costs. It is CLD/HONI conclusion that none of the options provided are sufficient to support the elimination of standby charges, nor is it likely that a rate design for more traditional customers could eliminate the need for standby charges.

CLD/HONI considers it to be very important that Board staff conduct additional detailed analysis on all options that the Board considers to be acceptable. More detailed impact analysis will inform the final selection of the rate design to be adopted in the future. CLD/HONI also strongly recommends that a working group of stakeholders be closely involved in the next phase of this project. The release of the next report by OEB Staff aided by the working group and further analysis should be subject to another round of comments from all interested stakeholders. Following the next phase, in order to obtain more information on the effects of any new rate design, the ultimate implementation should be phased in with "pilot projects" undertaken by LDC "volunteers" for implementing the most promising rate design options.

Finally, CLD/HONI also urges the Board to consider the comments in this submission as they relate to the future of the industry. The Board is encouraged to address the longer-term issues with follow up processes that will evaluate the implications and appropriate policy response to the innovations that are expected to challenge the industry in the next five to ten years. Climate changes issues and the prospect of grid parity for independent electricity supply will have implications that will require radical adaptations of both the regulatory process and utility operations.

Appendix A: Additional Data on CLD/HONI Customers

The information provided in this Appendix is intended to illustrate the wide range of customer consumption patterns that exist among commercial and industrial customers, all of which can lead to a significant difference in the bill impact and response to the Board staff rate design proposals.

GS < 50 kW Customer Data

The data below shows that the difference in average annual consumption levels between customers in the GS<50 kW class at the lowest and highest consumption ranges can vary by a factor of more than 50.

Enersource GS<50 kW (annual)

Quantile (by customer count)	min	max	avg
10%	-	5,246	2,912
10-20%	5,247	8,675	6,987
20-30%	8,687	12,274	10,456
30-40%	12,279	16,473	14,278
40-50%	16,474	21,797	19,022
50-60%	21,798	29,226	25,237
60-70%	29,229	40,723	34,554
70-80%	40,724	58,985	49,132
80-90%	59,017	94,838	74,468
90-100%	94,848	589,012	142,715

Hydro One GS< 50 kW (annual)

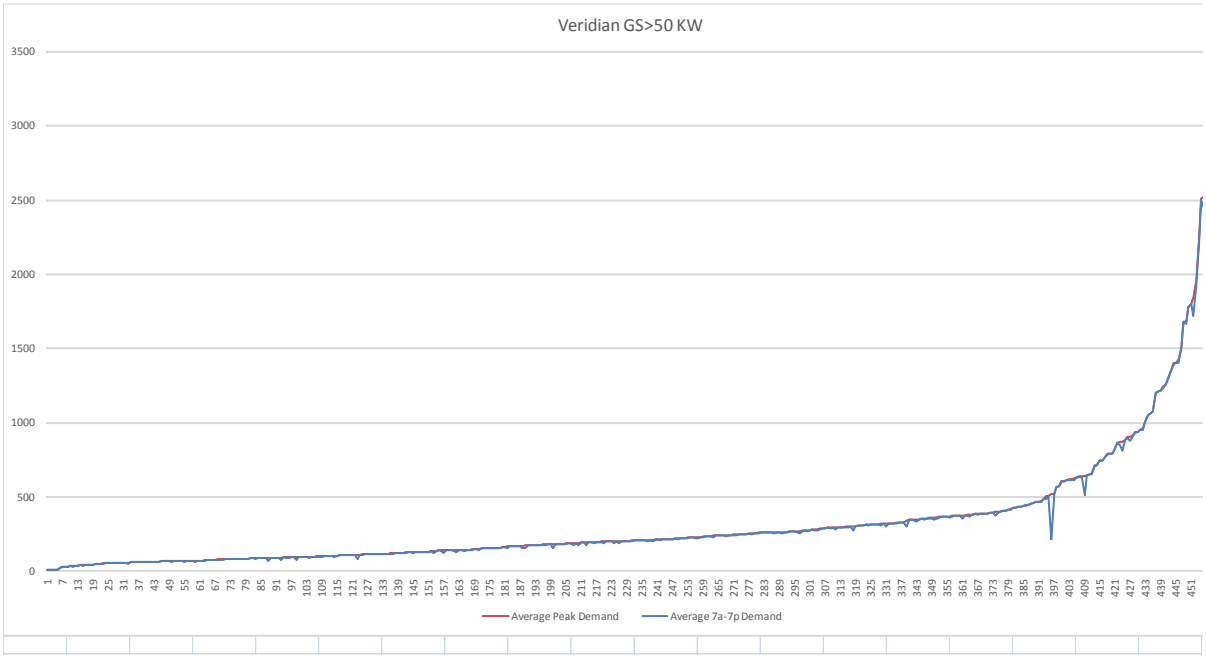
Quantile (by customer count)	min	max	avg
10%	0	1,107	484
10-20%	1,107	2,998	2,001
20-30%	2,998	5,302	4,102
30-40%	5,303	8,186	6,676
40-50%	8,187	11,931	9,959
50-60%	11,932	16,935	14,294
60-70%	16,938	24,281	20,383
70-80%	24,283	36,653	29,792
80-90%	36,656	61,887	47,435
90-100%	61,889	6,058,162	107,873

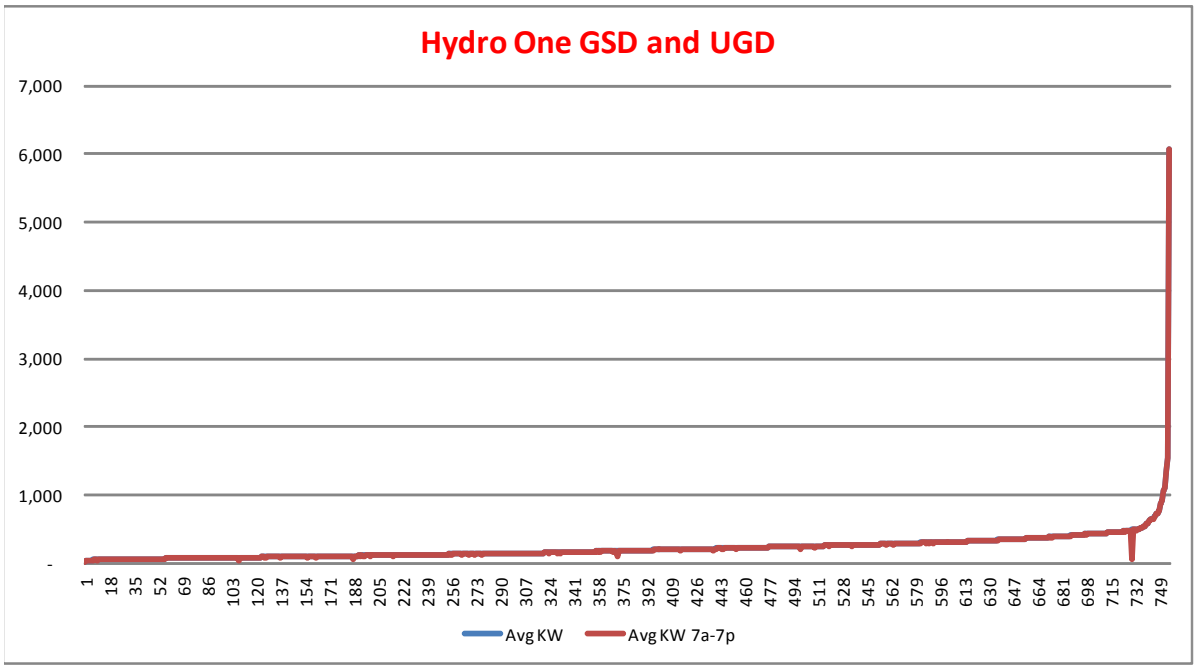
PowerStream GS<50 kW (annual)

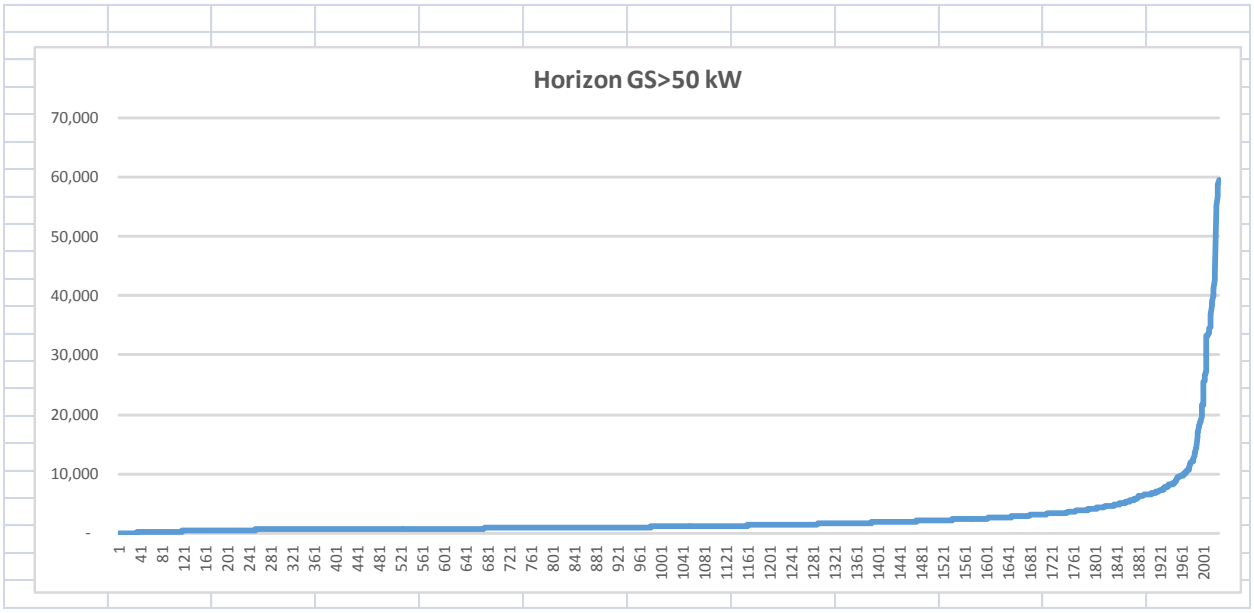
Quantile (by customer count)	min	max	ave
10%		3,969	1,972
90-100%	81,768	690,963	127,738

GS > 50 kW Customer Data

The data below shows that there are a relatively small number of customers within the GS>50 kW class that can have significantly higher consumption than that of the majority of customers within the class.



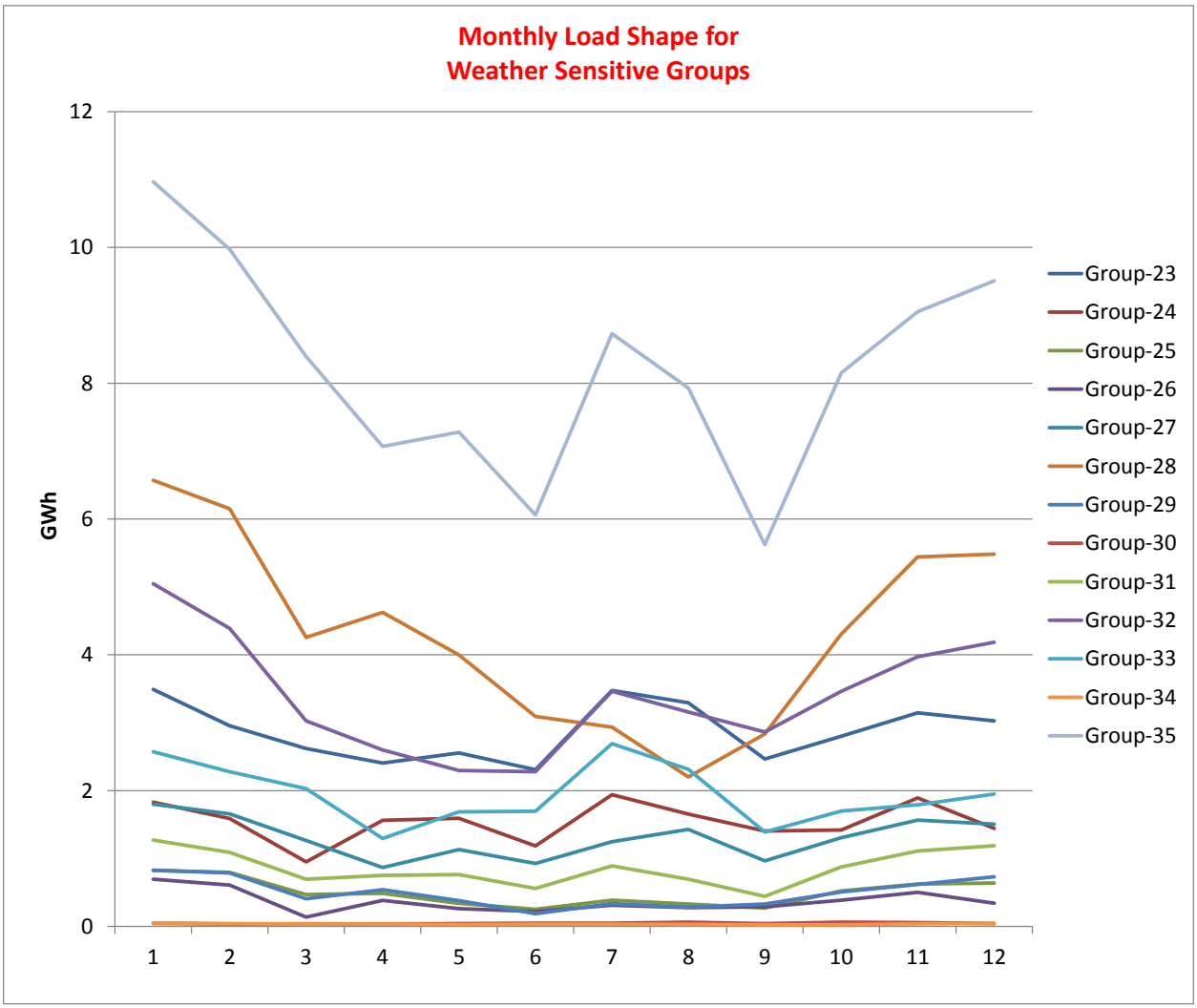

Hydro One GSD and UGD
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1
18
35
52
69
86
103
120
137
154
171
188
205
222
239
256
273
290
307
324
341
358
375
392
409
426
443
460
477
494
511
528
545
562
579
596
613
630
647
664
681
698
715
732
749
Avg KW
Avg KW 7a-7p

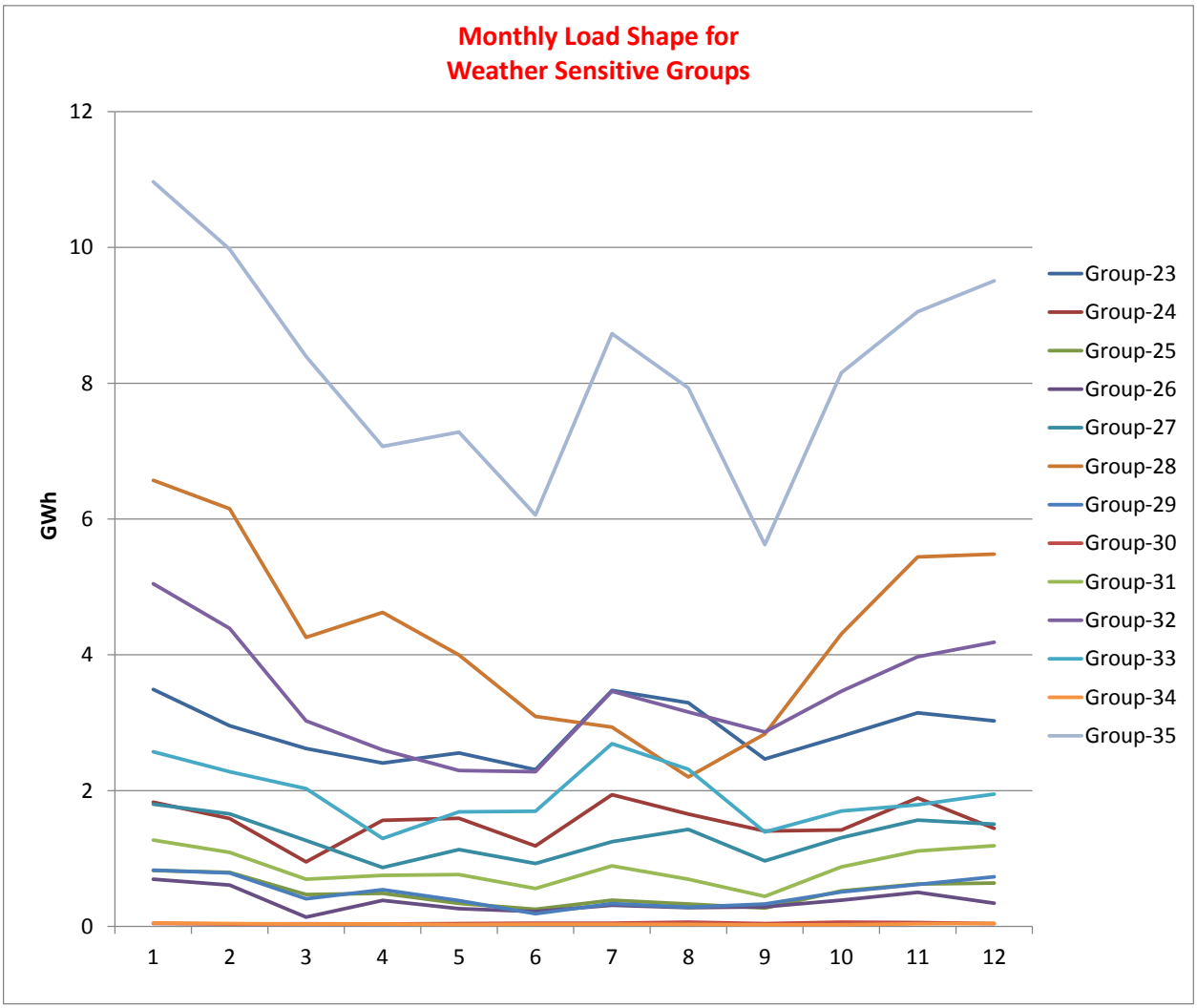

Horizon GS>50 kW
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
1
41
81
121
161
201
241
281
321
361
401
441
481
521
561
601
641
681
721
761
801
841
881
921
961
1001
1041
1081
1121
1161
1201
1241
1281
1321
1361
1401
1441
1481
1521
1561
1601
1641
1681
1721
1761
1801
1841
1881
1921
1961
2001

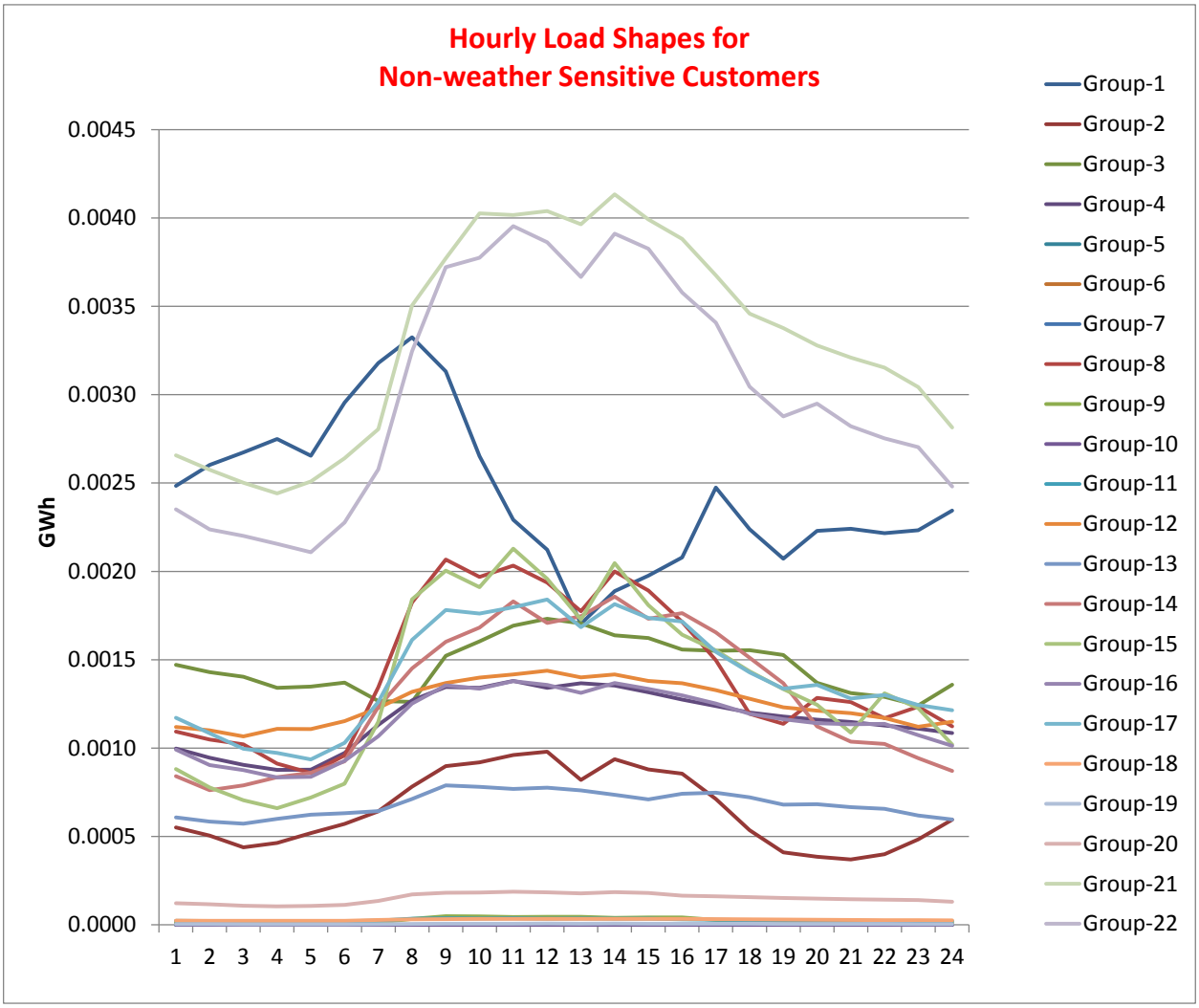
Variation in Commercial and Industrial Customer Consumption Patterns

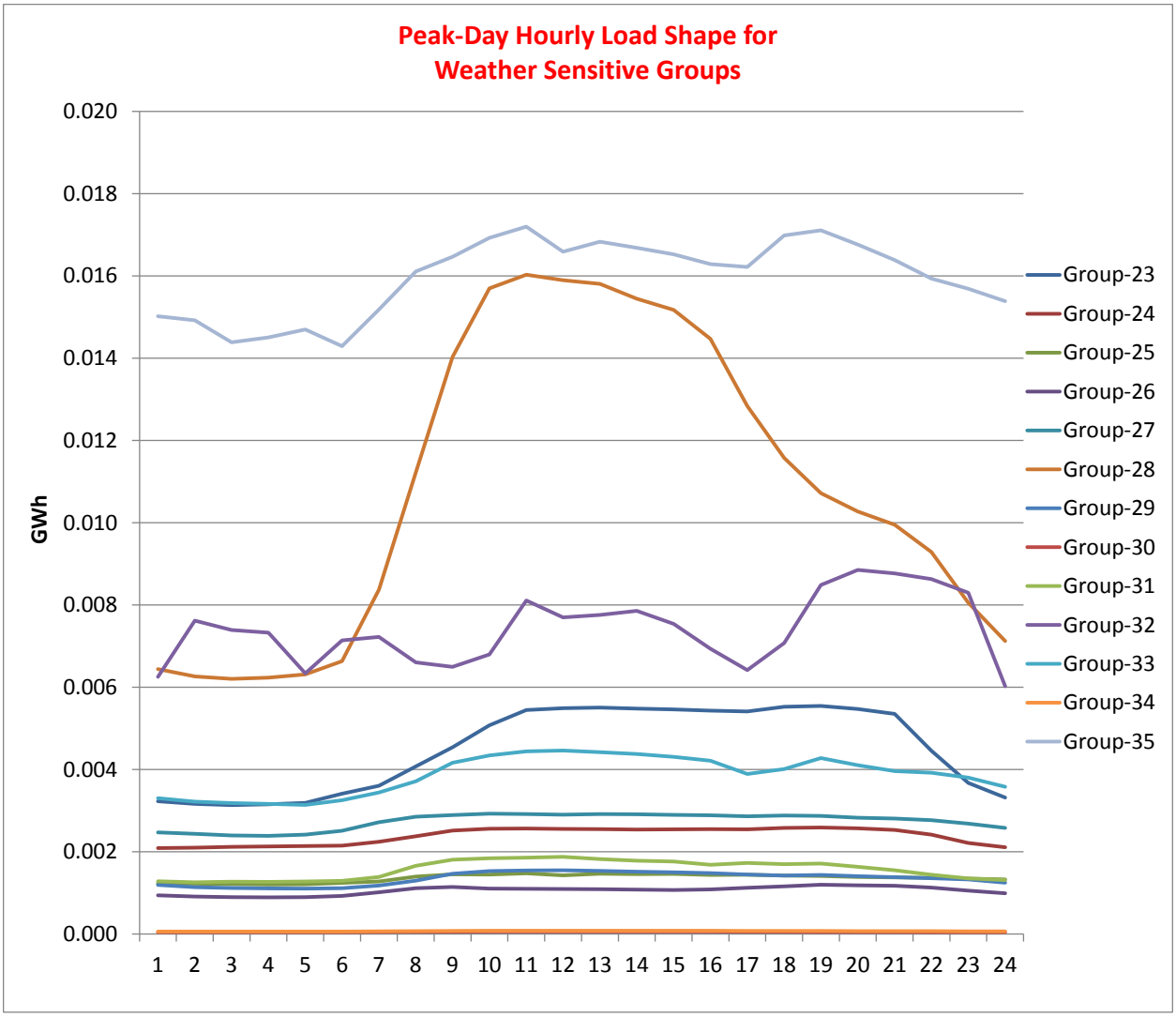
As another example of the large variability that can exist in the consumption pattern of industrial and commercial customers, the data below illustrates the fundamental differences between both monthly and hourly load patterns (based the OEB approved load shapes used for cost allocation analysis for Ontario LDC's in 2006) for the following 35 customer groups:

1 Agriculture & Forestry
2 Mining, Oil & Gas Exploration
3 Water & Sewage & Other Systems Manufacturing
4 Food, Beverage & Tobacco
5 Textile
6 Clothing
7 Leather
8 Wood Product & Furniture
9 Paper
10 Printing
11 Petroleum
12 Chemical
13 Plastics & Rubber
14 Non-Metallic Mineral
15 Primary Metal
16 Fabricated Metal Product
17 Machinery
18 Computer and Electronic Products
19 Electrical Equipment
20 Transportation Equipment
21 Miscellaneous Manufacturing
22 Wholesale Trade & Other Services
23 Retail Trade & Restaurant & Personal Care Services
24 Grocery Stores
25 Warehouses
26 Multi-residential Buildings
27 Office Buildings
28 Education – Elementary
29 Education – all others
30 Hospitals
31 Nursing & Residential Care Facilities
32 Arts Entertainment & Recreation
33 Accommodation
34 Public Administration
35 Other


Monthly Load Shape for
Weather Sensitive Groups
GWh
0
2
4
6
8
10
12
1
2
3
4
5
6
7
8
9
10
11
12
Group-23
Group-24
Group-25
Group-26
Group-27
Group-28
Group-29
Group-30
Group-31
Group-32
Group-33
Group-34
Group-35


Monthly Load Shape for
Weather Sensitive Groups
GWh
0
2
4
6
8
10
12
1
2
3
4
5
6
7
8
9
10
11
12
Group-23
Group-24
Group-25
Group-26
Group-27
Group-28
Group-29
Group-30
Group-31
Group-32
Group-33
Group-34
Group-35


Hourly Load Shapes for
Non-weather Sensitive Customers
GWh
0.0045
0.0040
0.0035
0.0030
0.0025
0.0020
0.0015
0.0010
0.0005
0.0000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Group-1
Group-2
Group-3
Group-4
Group-5
Group-6
Group-7
Group-8
Group-9
Group-10
Group-11
Group-12
Group-13
Group-14
Group-15
Group-16
Group-17
Group-18
Group-19
Group-20
Group-21
Group-22


Peak-Day Hourly Load Shape for
Weather Sensitive Groups
GWh
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Group-23
Group-24
Group-25
Group-26
Group-27
Group-28
Group-29
Group-30
Group-31
Group-32
Group-33
Group-34
Group-35