Ontario CHP Consortium

April 17, 2019 (Revised from April 12)

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

To Board Secretary Walli,

Re: Ontario CHP Consortium Feedback to Staff Report to the OEB on Commercial & Industrial Rates EB-2015-0043

Ontario's CHP Consortium has reviewed the OEB staff report on Commercial and Industrial Rate design, with a specific focus on the possible implications to Combined Heat and Power (CHP) projects and Distributed Energy Resources (DER) in general. The CHP Consortium does not agree with the recommendations in the Staff Report to the Board on the basis that it will result in barriers to new technology, unjust charges to customers, exacerbate grid defection, and erode price signals for customers to contribute to peak demand reduction. Most notable of all, the Board recommendations will not drive down long-term costs of the system.

As a result, the Ontario CHP Consortium recommends that the Board send back the Staff Report for further analysis and consultation and align the proceeding with the recently announced Responding to DER proceeding with a timeline for resolution.

Board Staff have produced a report that does not include adequate rationale or analysis commensurate with the significant cost impacts the recommendations will have on commercial and industrial customers. Furthermore, Staff have not completed a robust consultation or study on their recommendations and have not shared draft proposals and supporting analysis in a formal proceeding. It appears that limited feedback from interested parties was used to move from the discussion paper in 2016 that included multiple rate designs to the current formal recommended rate design, without showing how options were narrowed down.

With reference to the introduction of a Capacity Reserve Charge (CRC), while Staff have acknowledged that DERs can produce significant benefits to the system, any consideration of the value DERs such as CHP can provide are to be identified in a separate proceeding where a scoping paper has not yet been introduced. In order to properly assess rate impacts, consumers need to understand how both the costs and the benefits of DERs will be determined and separating these proceedings makes it impossible to do so.

CHP Consortium View on Rate Design

The Ontario CHP Consortium recognizes that distribution utilities play an important role in Ontario's electricity system. Furthermore, the Consortium recognizes that all DERs, including CHP, need to pay their fair share of costs. However, over time all ratepayers will benefit from DERs, and so it makes sense for all ratepayers to bear some of the costs of introducing DERs onto the system.

The Staff Report to the Board is explicit in being concerned with the revenue requirement of utilities in its recommendations for commercial and industrial rates, and yet there is no direct link to how the proposal will reduce system costs. The objectives set out in the Ontario Energy Board Act are to "1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service, and 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry."

In order to meet its objectives, the CHP Consortium puts forward that the Board should also be concerned with how to drive down the costs of operating the system as much as reasonable and how to keep them as low as possible. The Board, in ensuring there is a financially viable electricity industry, needs to carefully consider and put forward a framework that gives utilities an incentive structure on how to make sound investment decisions that are in their interests and those of all customers.

One of the stated OEB objectives is: "facilitate customer adoption of technology to manage energy use and costs, including the installation of distributed energy resources". This is an acknowledgment of the benefits DERs can provide to the system. And yet DER investments and installations are not proceeding as well as they could due to several regulatory factors.

- The costs and risks of current standby charges and the proposed CRC,
- Gross load billing on network charges,
- High cost and uncertainty of interconnection (studies, protective relaying, lines and transformers etc.)
- Lengthy and uncertain amount of time required to go through all the study, design and construction steps with distributors and transmitters.

The CHP Consortium recommends the Board consider all the various charges and rates in order to assess how bills impact customers. We understand that the Board is currently considering distribution charges, but we encourage the Board to look at the entire set of costs and benefits of DER investments.

Rationale for Recommending Further Work by Board Staff

The Ontario CHP Consortium and signatories recommend that OEB Staff perform further analysis and consultation to a commensurate level to the impacts the changes will have on customers.

Inadequate Analysis

OEB Staff have not provided the robust analysis customers and interested parties expect given the potential magnitude of rate impacts on customers.

The Staff Report's Appendix B only looked at 2 scenarios under the assumption that a load displacement project would result in lost revenue to a distributor. While some data curves are shown there is no supporting data from which interested parties can conduct their own analysis. The analysis did not consider consumer benefits or benefits to all consumers from deferring potential upgrades, as well as the flexibility the load displacement project provided the utility to use existing infrastructure for customer growth, managing outages, or other benefits.

In order to better assess the impact of the Staff's proposal on bills, one of the CHP Consortium members used their own actual consumption data. Although impacts will really vary depending on the customer specifics, in this case, the CHP customer has estimated that their overall electricity bill will jump by between 50% and 100+% if the Board moves forward with the recommendations.

This industrial customer's all-in electricity bills last year were $150,000. This facility used on-site CHP to produce all the required power 24x7.

The proposed Capacity Reserve Charge (CRC) is going to add, using the OEB Staff definition of "nameplate" generation on site, a further $152,528 per year (at current distribution rates). If one assumes OEB Staff's definition of nameplate is more about how much load could be displaced on-site (maximum onsite load), this would work out to about $78,300 extra per year, a 52% bill increase.

Looking at what this customer needed on a non-coincident basis using data from 2018, it is about $41,760 extra per year. On a coincident basis, the charge would probably have been $0. In other words, this customer is consuming electricity off-peak when there's a surplus and is not contributing any demand during peak, but under the Staff proposal to the Board, this customer's bill is going to skyrocket.

This customer example is based in part on assumptions and estimates. Unfortunately, the Staff Report does not contain adequate detail and analysis that would enable customers to accurately estimate what their bill impacts would be.

The Navigant report[1] starts its analysis with a Capacity Reserve Charge (CRC) without looking at other options, such as building in interruptible rates more consistent with other jurisdictions the CHP Consortium identified, or rates that would include some elements of contracted demand and daily/monthly demand-based charges.

There was no CRC in the discussion paper in 2016, and so there was no formal consultation showing an analysis of how a CRC compares with other options. Board Staff have concluded that the CRC is the best design option but have not put forward compelling analysis or evidence showing how this is the best rate design for current and future customers and all ratepayers.

The CHP Consortium provided feedback to Board Staff in 2017 that rates should be based on coincident peaks as much as possible as this is the driver of real costs to the system. However, Board Staff have omitted any analysis showing how or why coincident peaks should not be the starting point for setting rates. This aspect of the Report requires further analysis and rationale from Board Staff.

With respect to the table showing technology-specific capacity factors, the CHP Consortium puts forward that these numbers can vary significantly and should be considered on a customer-specific

[1] Navigant for the Ontario Energy Board. Alternative GS Distribution Rate Analysis Appendix B (2019): https://www.oeb.ca/sites/default/files/Appendix-B-Navigant-Alt-GS-Dx-Rate-20190221.pdf

basis. Every behind the meter CHP project is different, and the installed capacity and number of generation units can vary widely and for a variety of customer driven reasons

The customer should nominate how many CHP units are considered when calculating the CRC. If a customer installs three separate CHP turbines at 5 MW each, the probability of all three going down is zero, and therefore the customer might only require a fraction of total nameplate capacity as backup.

Inadequate consultation

OEB Staff have not shown how their consultation has engaged a cross section of affected parties in a timely and reasonable fashion.

The 2016 discussion paper received many comments from other groups in favour of coincident peaks, including the Association of Major Power Consumers in Ontario (AMPCO), the Association of Power Producers of Ontario (APPrO), Canadian Solar Industries Association (CanSIA), the Builders and Owners Management Association (BOMA), the Independent Electricity System Operator (IESO), the School Energy Coalition (SEC) and the Canadian Federation of Independent Businesses (CFIB).

In April 2017 Board Staff set up informal discussions with various groups, including the Ontario CHP Consortium, to share a concept proposal. CHP Consortium members were clear with Board Staff at that time that charges should be based on coincident peaks, providing feedback very much in line with the formal responses Board staff received in response to their 2016 discussion paper.

Now the formal Staff Report to the Board shows a reversal from coincident peaks and instead introduces a CRC on customers. These recommendations pose significant changes from what was formally introduced during consultations and introduces significant investment risk for customers.

Lack of jurisdictional scan

OEB Staff have not provided evidence of how other jurisdictions are approaching this issue. We have submitted for your consideration just a few of the American State policies on standby charges as applied to CHP.[2]

Arizona Public Service Company provides standby service to customers through a specified contract demand. A high demand-based reservation charge in addition to a customer charged is assessed every month, while actual usage is billed through moderate energy charges.

Southern **California** Edison's rate is more demand-based than PG&E's, which uses a high energy charge to bill actual usage. Both rates are, for the most part, neutral to CHP.

In **Colorado**, customers wishing to secure standby service for CHP systems may contract with Xcel Energy for a specified amount of standby capacity.

In **Connecticut,** CL&P has withdrawn its unfavorable-to-CHP Rate 985, and has replaced it with Rider N, which can be attached to one of several rates.

[2] American Council for an Energy Efficient Economy (ACEEE) Jurisdictional Scan of US Standby Rates (2018): https://database.aceee.org/state/standby-rates

In **Florida**, Progress Energy Florida, Inc. provides standby service via a contractual agreement for a particular amount of demand. Service is charged at a rate balanced between demand and energy charges.

In **Illinois**, Exelon/Commonwealth Edison's Rate 18 is predominately demand-based, but it does average out three separate peak demand periods over a month to discern that demand.

In **Maryland,** BGE provides standby service for distributed generation via contracts specifying particular amounts of standby capacity.

A submission by the Midwest Cogeneration Association to the Indiana Utility Regulatory Commission also highlighted the movement of US states away from introducing punitive standby charges such as the Staff's proposed CRC.[3]

"Here in Indiana, the Commission has a model of a proportional standby tariff in NIPSCO's Rider 776 which charges a daily, rather than fixed, demand charge based on standby use during peak hours. In Minnesota, Xcel Energy Company's standby use demand charges are even more closely proportionate to actual standby use and utility costs because they are based on the actual hours of use of standby (kWh) and apply only during peak hours. In a recent Minnesota Public Utility Commission docket examining four utilities' standby tariffs (Docket No. E999/CI-15-115), the MN PUC also recently approved a negotiated settlement reducing Xcel Energy's standby reservation fee to reflect the 5% outage rate of CHP systems. PUC Order, April 5, 2018, Docket No. E999/CI-15-115.

In another example of proportionate charges, Minnesota Power Company's standby tariff reservation fee is based on the standby customer's actual outage rate after the first year of operation and is adjusted annually – providing a clear price signal for minimizing outages. In contrast, fixed reservation fees and demand charges that don't reflect a customer's actual standby usage or that ratchet maximum usage in one month over the next eleven months send the wrong price signal to standby customers for efficient use of grid resources and optimization of CHP systems. ***Why try to minimize use of the utilities' resources if you are paying for it anyway?"***

In **Missouri**, for on-site generation, Kansas City Power and Light Company provide standby service through executed contracts for a specific amount of demand.

Nevada Power Company's Schedule LSR is applicable to systems between 500kW and 20MW in capacity. This schedule is favorable toward CHP and is viewed as incentivizing reliability and maintenance with its demand charge structure for forced outages. The energy charges in this schedule are moderate

In **Pennsylvania**, for customers desiring standby service, PECO Energy Company will develop a contract for a specific amount of demand capacity. Charges will then be based on the contract demand and actual energy use.

Wisconsin Electric Power Company's Primary Service Optional Standby service is negotiated through a contract that specifies a particular demand.

[3] Midwest Cogeneration Association Comments to the Indiana Utility Regulatory Commission (2017): https://www.in.gov/iurc/files/MCA%20-%20IN%20-%20IURC%20GAO%202017-3%20Comments%20on%20Utility%20Standby%20Rates%20-4-20-18.pdf

Lack of consideration of DER benefits

OEB Staff have acknowledged the potential benefits of DERs in recommending a capacity reserve charge and this should be considered as part of any proceeding that recommends changes to rates.

Board staff have put forward consultative proceedings on rates and DER benefits on different tracks that are not aligned in any way that stakeholders can put together. At the time of preparing this submission, scoping papers identifying a list of issues have not been produced for the Responding to DERs or Utility Remuneration proceedings. The 2016 discussion paper referenced DER credits and the CHP Consortium would like to understand what happened to these concepts, as they have disappeared and have been replaced instead with the introduction of a CRC.

Principles to consider in revisiting Commercial and Industrial Rate Design

As part of our recommendation for further analysis and consultation, the CHP Consortium puts forward the following Principles for the Board and Staff's consideration.

1. Consider the System Benefits of DER

There are costs of introducing DERs, including CHP onto the system, but there are also benefits, and any standby/backup charges being considered should be calculated based on both benefits and costs.

The energy infrastructure in Ontario is a fully integrated system, with transmission systems, distribution systems, generators and load customers. When DERs are connected to this system, initially a case could be made that keeping capacity available is a cost that should be covered by DERs. However, over time, as more and more DERs are connected, the cost of keeping capacity available will disappear and cost savings resulting from avoided investments in transmission and distribution systems will offset the initial investment in transmission and distribution capacity pre-DERs. The logical outcome is that while they may initially add some cost, when viewed over an extended period of time, DERs will become cost neutral. Rather than burdening the system with the cost of trying to estimate the short-term impact of DERs and burdening them with these costs, DERs should be considered to be cost neutral and treated as such.

There are several high-profile examples where leading jurisdictions are carefully considering the potential benefits of DERs and putting them into practice to help defer the need for costly infrastructure upgrades. The US Department of Energy published a Flexible Combined Heat and Power (CHP) Systems Factsheet,[4] and complementary study focused on how CHP could help alleviate much of the issues affecting California's grid.[5] In New York, ConEdison was able to defer a costly Brooklyn Transformer Station upgrade by establishing incentives for large users to reduce peak demand and through an auction for non-wires alternatives. Another example: NYSERDA recognized the benefits of DER CHPs by paying a performance incentive for the installation of CHP, with an additional bonus on projects in "targeted zones".[6]

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[4] US Department of Energy, Flexible Combined Heat and Power (CHP) Systems (2018) https://www.energy.gov/sites/prod/files/2018/01/f47/Flexible%20CHP%20Comms_01.18.18_compliant.pdf

[5] US Department of Energy, Modeling the Impact of Flexible CHP on California's Future Electric Grid (2018): https://www.energy.gov/sites/prod/files/2018/01/f47/CHP%20for%20CA%20Grid%201-18-2018_compliant.pdf

[6] US Department of Energy, Combined Heat and Power (CHP) Performance Program https://www.energy.gov/savings/chp-performance-program

Other reports by prominent energy research organizations such as the University of Toronto's MOWAT Centre reference New York State's efforts in the Reforming the Energy Vision (REV) Proceeding:[7]
"*New York is well known for its far-reaching Reforming the Energy Vision (REV) proceeding. New York is on a path to change fundamentally the way utilities are regulated, making utilities the distribution platform on which energy resources compete. The rate-making incentive structure being considered would no longer cause utilities to prefer large infrastructure projects over energy efficiency and distributed resources, and performance incentives would be provided for facilitating policy objectives like integrating renewables and reducing peak load."*

Close to home, the 2013 Long Term Energy Plan recognized the benefits of CHP: "The OPA will undertake targeted procurements for Combined Heat and Power (CHP) projects that focus on efficiency or regional capacity needs". Ontario would do well to look at its historical support for CHP installations as an example. The Windsor area in the 90s saw a large build out of CHP facilities as part of the Local Infrastructure Response Plan (LIRP) that was put in place to defer a 115kV line build out. Today, a similar pattern is repeating in Leamington to accommodate the explosive growth in greenhouses, which the utilities cannot manage through traditional infrastructure. Increasingly, some of these facilities are considering operating completely in islanded mode as a result of introduced standby rates. The introduction of a CRC increases the risk that more customers will look at grid defection as a realistic possibility.

The Staff Report to the Board does not consider discussions happening in parallel whereby CHP and other DERs would potentially have an opportunity to provide services back to the grid, enabled by evolving policies such as the IESO's market renewal, which could see CHP be part of the solution towards addressing the identified 2,000 MW capacity gap that is expected to materialize in the mid-2020s. Increased penetration of CHP and other DERs would reduce overall demand for electricity from the provincial grid, resulting in a long term decrease in electricity commodity costs, contributing to the government's long term energy and economic objectives.

The CHP Consortium members are hopeful that these emerging opportunities for CHP will provide for more line of sight from system operators to behind the meter CHP projects, allowing them to provide more benefits to the IESO, utilities and the overall system. By contrast, the introduction of CRC charges instead will encourage opposite behavior, pushing customers to consider going off-grid in order to protect their business interests.

2. DER customer benefits and applying fair standby rates

The Customer benefits of CHP are clear. CHP helps customers manage their energy costs, improve business continuity through enhanced resilience, as well as ensuring adequate power quality. The CHP Consortium members were able to identify several cases where distribution utilities were not able to supply the quality of power manufacturers required to safely and effectively operate sensitive equipment, effectively forcing these industrial customers to install CHP. To then introduce a CRC would mean these customers would be paying twice for the power they needed to stay in business.

[7] University of Toronto Mowat Centre report (2017), Future Drivers and Trends Affecting Energy Development in Ontario: Lessons Learned from Germany, the US and Beyond, https://mowatcentre.ca/wp-content/uploads/publications/136_EET_future_drivers_germany_us_beyond.pdf

CHP technology has come a long way and the flexibility of these systems to meet customer needs and integrate with other energy systems continues to improve. CHP is not going away, and customers are going to continue to want to install these systems for a variety of reasons.

There is a customer benefit to being grid connected, and so if customers with DERs, including CHP, want to stay connected and use the grid for standby/backup then there are costs that the customers should pay. However, if standby charges are too high then customers will look at all their options. An increasing number of customers are looking to CHP to address power quality issues. Should these same customers then be hit with CRC charges, they will be looking at all their options. The more restrictive the policies on DERs, the more customers will look to island as a realistic option.

3. Costs should be based on coincident peak as the driver of system costs

As set out in the OEB commissioned report in 2007, rate design should provide a signal that effectively encourages customers to contribute to peak demand reduction, as this is what drives system costs.[8]

Standby Charges

5. Specific considerations for setting and designing standby rates include the following:
   - Rates should be designed to reflect the costs, net of any offsetting benefits;
   - Standby rates should reflect the various gradations of services (i.e., voltage levels) provided;
   - Rates should not create artificial barriers to DG;
   - The rate structure should be simple and easy to understand by the DG consumer and to administer by the LDC;
   - Rate design should encourage the following:
     - Reduced redundancy of installed capacity;
     - Operation of DG plant during on-peak hours; and
     - Utilization of excess grid capacity during off-peak hours.

The OEB's own discussion paper in 2016[9] acknowledged the need to tie customer rates to coincident peaks.

"Current OEB staff thinking is that the underlying rate design should… reward the active customer for reducing one of the primary cost drivers i.e. peak capacity. Reducing peak capacity will lower the distributor's investment needs to meet peak capacity and save money over time. Building this driver into the rates will align the interests of the customer and the distributor. The expectation is that a rate design that addresses underlying cost drivers will lead to each customer paying their fair share of the system."

This same discussion paper made no mention of introducing Capacity Reserve Charges, which moves away from the concept of introducing coincident peak charges and results in unfair charges on customers that have installed or are looking to install CHP.

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[8] ESS Consulting for the Ontario Energy Board, Discussion Paper on Distributed Generation (DG) and Rate Treatment of DG (2007).

[9] Ontario Energy Board, EB-2015-0043, Staff Discussion Paper, March 31, 2016,

An extreme example of where the CRC would be misapplied is when a CHP would shut down for scheduled maintenance overnight during a shoulder season. Not only would this shutdown not be contributing to the peak, it would be helping the system by absorbing excess supply when Ontario has been experienced surplus baseload issues. This type of scheduled shutdown should not generate additional standby payments as proposed.

The CHP Consortium encourages the Board to revisit how to apply coincidental peak charges and price signals to customers as a way of reducing long term costs of the system, for the benefit of all customers. The province-wide installation of smart meters and availability of interval data allows us to better correlate customer and system peaks than ever before, and we should leverage this capability.

4. Board should recognize the difference between micro and large-scale DERs

The CHP Consortium agrees with the objectives set out by the board to accommodate innovative technologies. The Board should seriously consider policies that would facilitate, rather than act as a barrier to the adoption of those innovative technologies, especially for smaller customers that are typically limited in their energy management options.

New technologies to Canada, including microCHP, are increasingly prevalent in jurisdictions in the US, Japan and Europe and have seen increasing market penetration over the last decade. Mass market adoption of these technologies can lead to significant cost reductions for the system over time.

If the Board is committed to introducing a CRC, then it should consider setting a threshold under which a CRC would not apply to smaller customers under 250 kW. Standby charges for customers of this size serve as a significant barrier to the adoption of DER technology, for a few reasons:

- The per-kW cost of microCHP and other small-scale DERs is considerably higher for smaller installations, than for large-scale plants (often 2-3 times more). Additional costs due to standby charges can easily ruin the economics of many projects.
- Customers of this size – such as the multi-residential sector – often have limited ability to adjust their usage profiles or perform plant maintenance outside of peak hours. These customers then run a significant risk of double-paying for their delivery service during months where their plants are down for maintenance (i.e. they would be paying their CRC in addition demand charges on their full peak demand requirements)
- These customers are often much less sophisticated than large industrial customers when it comes to understanding and managing their electricity supply. If installing DERs means they will see an additional charge on their utility bill that they didn't have before – this alone could scare off many potential adopters of DER technology.

Additionally, standby charges for customers of this size are neither fair nor necessary. If only a few customers adopt DERs, then the impact to the utility grid is negligible due to the small size of the customers. On the other hand, if mass-market adoption of microCHP occurs, then this will reliably drive down long-term system costs. While any individual customer may need grid capacity for their full load requirements in the event of a DER outage, the combined impact of such outages on coincident peak load would be minimal as the probability of all such customer plants being down simultaneously is essentially zero. The result is that, in aggregate, microCHP customers don't require anything near capacity for their peak demand, and it is not fair to make them pay for it.

5. Provide optionality for firms in terms of contracting for firm/interruptible capacity

The rate design being considered is too prescriptive and should not be based on nameplate capacity only. The capacity factors proposed are theoretical and might not apply to a given CHP facility, as not all installations are equal and there might be significant variation between facilities.

The CHP Consortium recommends the Board consider a framework for the CRC where customers can lower costs by choosing interruptible rates, relying on the precedent already in place for setting interruptible natural gas rates. This would allow customers to choose how much capacity they need. For example, a customer with multiple CHP units might only need backup for the single largest unit, as the chances of multiple units going down simultaneously is very small.

Technologies that are more reliable should not have to pay a higher CRC. As Staff's current proposal stands, less reliable technologies such and Wind and Solar would have much smaller capacity factors, and hence much smaller CRCs than more reliable technology such as CHP and battery storage systems.

6. Small commercial customers (<10 kW) need a way to reduce their distribution costs using innovative technologies

The Staff Report proposes to move General Service customers <10kW to fully fixed distribution rates, as has previously been done with residential customers. The rationale is that these customers have limited ability to reduce their peak demand or shift their load, and that moving them to a fixed charge provides stability and peace of mind. It assumes that customers of this size will not or cannot invest in DER technology to reduce load.

While at this moment, DERs are primarily being considered among larger customers, innovation and technological change may well change this reality in the not-so-distant future. Innovative new technologies, such as heating boilers that also produce small amounts of electricity, are already in development. Such technology, if adopted at a large scale, could have enormous long-term benefits in removing demand from distribution systems and smoothing out peak demand. However, the ability to maximize cost savings on electricity will be a key driver to the adoption of these technologies. Faced with fixed, unavoidable distribution charges, customers will be less inclined to invest in these smaller scale DERs that would otherwise provide system benefits that could drive down long-term system costs.

Ultimate, there is no good reason, other than simplicity, to move GS <10kW customers to a fixed distribution charge. If the Board feels it is necessary to move away from a consumption-based delivery rate, it should move to a delivery rate that accurately reflects the individual customer's costs to the delivery system – i.e. charges based on the customer's coincident peak demand.

7. Customers that reduce demand should be treated equally

Customers can reduce peak demand and costs to the system through demand response, efficiency projects, and DERs, and these measures should be treated the same.

CHP shouldn't be treated unfavourably when other conservation methods and fuel switching are also viable that don't require the application of a Capacity Reserve Charge.

The Ontario CHP Consortium thanks the Board for considering our comments on the Staff Report on Commercial and Industrial Rates. We look forward to the opportunity to continued engagement with in this proceeding.

Yours Sincerely,

Richard Laszlo, Chair
Ontario CHP Consortium
A QUEST Working Group

CHP Leaders signing on to this letter:

- 2G Energy Inc.
- Cascara Energy
- CEM Engineering
- CWB Maxium Financial
- dbs Power and Energy
- Efficiency Canada
- Emerald Energy from Waste
- Fourcaudot Energy Solutions
- EPS AB Canada Ltd.
- HCE Energy Inc.
- H.H. Angus & Associates
- INNIO
- Kirkland Lake Gold Ltd. Taylor Mine
- Markham District Energy Inc.
- Powerlink Canada
- Sundara Energy
- VIRTUAL Engineers (VE Collective Inc.)