POLLUTION PROBE INTERROGATORY 1

<u>QUESTION</u>

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

1. Ref: Exhibit C, Tab I, Schedule I, pg. 3

Please provide a break-out of the net annual peak demand reduction actually achieved or forecasted to be achieved by OPA program (e.g. DR1, peaksaver, etc.) for each year from 2005 to 2014 inclusive.

For each program and for each year, please also provide the program's:

a) TRC Test benefit cost ratio;
b) Levelized unit electricity cost of reducing demand by 1 kW;
c) Free-rider rate;
d) Report(s) which provides the market evidence and analysis to support the OPA's free-rider rate estimate;
e) Number of participants; and
f) Budget.

<u>RESPONSE</u>

The requested information for Pollution Probe Interrogatories 1 and 2 is provided as Attachment 1 to this exhibit. Please note the following:

- There were no OPA-funded CDM programs delivered in 2005.
- Data for programs implemented in 2006-2009 are final; data for 2010 programs are based on forecasts from November 2009.
- Levelized unit conservation delivery cost is given in $/kWh for electric energy conservation and $/kW-yr for electric capacity conservation.
- The OPA generally estimates free-ridership at the initiative/measure level combination. A blanket free-ridership rate at the initiative level is generally not considered, but has been calculated and shown here for the purposes of this request, at the initiative level as a weighted average.
- The number of participants for prescriptive measure-based initiatives is given in number of units of relevant measure, i.e. for a coupon redemption initiative, the unit of measure for participation is number of coupons, not number of households. The number of participants for a custom project-based initiative is the number of customers, e.g. for a retrofit initiative, the number of participants are the number of retrofit projects.

- It is assumed that the request for 'budget' refers to the budget approved by the OPA Board of Directors (prior to implementation), as opposed to the actual expenditure (determined after implementation).
- Initiatives are contained by year and thus do not span years. Annual savings results are given for each initiative and can be summed over years to give cumulative savings.
- Not all data requested is available.
- Reports from third party evaluations of previous OPA-funded programs are anticipated to be available on the OPA website in Q1 2011.

POLLUTION PROBE INTERROGATORY 2

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

2. Ref: Exhibit C, Tab I, Schedule I, pg. 3

Please provide a break-out of the cumulative* annual energy reduction achieved/forecast to be achieved by the OPA by program for each year from 2005 to 2014 inclusive.

For each program and for each year, please provide the program's:

a) TRC Test benefit cost ratio;
b) Levelized unit energy cost of reducing electricity consumption by 1 kWh;
c) Free-rider rate;
d) Report (s) which provides the market evidence and analysis to support the OPA's free-rider rate estimate;
e) Number of participants; and
f) Budget.

* For example, assuming the program saved 100 kWh in 2005 and an incremental 200 kWh in 2006, but only 90 kWh of the 2005 savings persisted in 2006, then the cumulative annual energy savings in 2006 would be 290 kWh (i.e., 90 + 200).

RESPONSE

Please see response to Pollution Probe Interrogatory 1, at Exhibit I-4-1, Attachment 1.

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POLLUTION PROBE INTERROGATORY 3

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

3. Ref: Exhibit B, Tab 2, Schedule 1

a) Please provide the total number of: a) residential; and b) small business customers that were enrolled in the peaksaver program as of December 31, 2010.

b) Please provide your best estimate of the total number of: a) residential; and b) small business customers that are eligible to enroll in the peaksaver program.

c) Please provide the forecasted number of: a) residential; and b) small business customers that will be enrolled in the peaksaver program as of December 31 for each of the following years: 2011, 2012, 2013, and 2014.

d) Has the OPA analyzed the benefits and costs of adopting more aggressive participant targets for its residential and small commercial peaksaver programs? If yes, please provide copies of the OPA's analyses. If no, please explain why not.

RESPONSE

a) Final participation numbers for 2010 peaksaver initiative are not yet available. The OPA estimates that the total number of residential customers enrolled in peaksaver as of the end of 2010 is 200,000 and that the total number of commercial customers enrolled in peaksaver as of the end of 2010 is 3,500.

b) For the new Province-Wide Residential and Small Commercial Demand Response initiative starting in 2011, the OPA is forecasting direct load control participation based on number of controllable devices rather than number of customers. The OPA estimates that the total number of eligible devices for load control within the 2011-2014 Residential and Small Commercial Demand Response initiative is 4.7 million.

c) For the new Province-Wide Residential and Small Commercial Demand Response initiative starting in 2011, the OPA is forecasting direct load control participation based on number of controllable devices rather than number of customers.

The OPA forecasts residential direct load control participation as follows:

- 2011: 37,125
- 2012: 59,400
- 2013: 74,250
- 2014: 76,725

The OPA forecasts small commercial direct load control participation as follows:

- 2011: 375
- 2012: 600
- 2013: 750
- 2014: 775

An enhancement of the initiative to better address the small commercial sector is planned for development in Fall 2011, by the OPA-LDC Working Group. It is anticipated that an enhancement of the initiative and value proposition for small commercial customers will support increased participation targets for the small commercial sector.

d) The current 2011-2014 Residential and Small Commercial Demand Response initiative participant targets were developed in collaboration with the LDC Working Group, based on a number of inputs, including: historical peaksaver participation rates, jurisdictional review, taking into account those already participating in peaksaver, and options for enhancing the value proposition to the customer. The forecasted direct load control participation for 2011-2014 is 250,000 compared to an estimated 203,500 peaksaver participants enrolled over the last four years. An enhancement of the initiative to better address the small commercial sector is planned for development in Fall 2011, by the OPA-LDC Working Group. It is anticipated that an enhancement of the initiative and value proposition for small commercial customers will support increased participation targets for the small commercial sector.

POLLUTION PROBE INTERROGATORY 4

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

4. Ref: Exhibit B, Tab 2, Schedule 1

Please provide the avoided cost (with respect to both energy and capacity) estimates that the OPA uses to calculate the cost-effectiveness of its CDM programs. Please provide a break-out of these estimates by year, season, time of day, generation, transmission, and distribution.

Please provide a break-out of the generation mix assumptions that are embedded in your avoided cost estimates (i.e. the percentages of the avoided capacity and energy supply that is solar, wind, biomass, water power, simple cycle gas, combined-cycle gas, combined heat and power, nuclear power, and imports.

Please provide the source(s) and copies of reports that support the OPA's avoided cost estimates (e.g. internal OPA analysis, a report by Navigant, etc.).

RESPONSE

The avoided cost estimates used by the OPA to estimate the cost-effectiveness of CDM program are shown in the "OPA Conservation and Demand Management Cost Effectiveness Guide", available at the following web address: http://www.powerauthority.on.ca/sites/default/files/page/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%202010-10-15%20Final.pdf

The energy shares of resource types that are on the margin in the 2007 IPSP Reference Plan underlying the avoided cost estimates are:

Coal	24%
Nuclear	1.4%
Biogas	38.3%
Combined cycle gas	30.6%
Single cycle gas	3.1%
NUGs	2.2%
Lennox	0.3%

(Totals may not add to exactly 100% due to rounding.)

The incremental capacity shares of resources making up the estimates of avoided costs found in the document referenced above are:

Combined cycle gas	62%
Single cycle gas	35%
Distributed Generation	3%

Support for the OPA estimates of avoided costs of CDM is found in the document referenced above.

The OPA's avoided costs are developed in-house using analytical models, and are described in Section 3.2.1. of the "OPA Conservation and Demand Management Cost Effectiveness Guide" referenced above.

POLLUTION PROBE INTERROGATORY 5

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

5. Ref: Exhibit B, Tab 2, Schedule 1

Please provide the OPA's estimates of Ontario's annual average and peak hour transmission and distribution system energy losses as a percentage of Ontario's total annual electricity generation and as a percentage of Ontario's peak demand.

RESPONSE

Provincial average transmission system losses of 2.5% and distribution system losses of 4.2% are used in the OPA's planning activities and in assessing the cost-effectiveness of Conservation and Demand Management programs found through this link: (http://www.powerauthority.on.ca/sites/default/files/page/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%202010-10-15%20Final.pdf).

Monthly peak transmission system losses are provided in the IESO's 18-month outlook (refer to Table 3.3.3 found at: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlookTables_2010aug.xls).

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POLLUTION PROBE INTERROGATORY 6

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

6. Ref: Exhibit B, Tab 2, Schedule 1

With respect to: a) the Electricity Retrofit Incentive Program; and b) the Industrial Accelerator Program, please provide the ranges of their average annual custom project financial incentives* per kWh as a percentage of the LUECs for the corresponding avoided electricity supply.

* For example, if the customer financial incentives are 5 cents per kWh for each kWh of first year savings only and if the project has an economic life of ten years, the average annual financial incentive is 0.5 cents per kWh assuming no discounting (i.e. 5 cents / 10 years).

RESPONSE

a) Electricity Retrofit Incentive Program

The OPA does not have a breakdown of average incentive costs for custom projects versus prescriptive projects for the Electricity Retrofit Incentive Program ("ERIP"). The most current verified results for ERIP (prescriptive and custom projects combined) are for 2009.

In 2009 the average levelized financial incentive per kWh for ERIP projects was approximately $0.01/kWh, which represents approximately 14% of the corresponding levelized cost of the avoided electricity supply costs.

b) Industrial Accelerator Program (Transmission Connected)

As of January 26, 2011, the Industrial Accelerator program does not have any project incentive agreements contracted with participants and therefore a range of actual average annual custom project financial incentives per kWh is not yet available.

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POLLUTION PROBE INTERROGATORY 7

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

7. Ref: Exhibit B, Tab 2, Schedule 1, pg. 16

a) Please provide the OPA's total cumulative CDM expenditures since 2005 as of December 31, 2010.

b) Please provide the total reduction in peak demand (MW) and energy consumption (MWh) in 2010 as a result of the OPA's CDM activities since 2005.

RESPONSE

a) The 2005 data is not available as the OPA did not separate the generation related program costs and the CDM related costs in the first year of its operation.

Conservation expenditures are primarily included within the Conservation division however there are additional expenditures incurred for supporting activities undertaken in other divisions, such as Finance or Legal. Please see the response to Board Staff Interrogatory 1, at Exhibit I-1-1.

Total expenditures (in $000's) for the Conservation division and program costs for 2006 to 2010 are provided below:

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
Compensation & Benefits	$1,603	$5,286	$6,431	$6,762	$8,140
Professional & Consulting Fees	$2,139	$5,316	$5,505	$5,949	$4,072
Conservation & Technology Funds	$1,053	$2,187	$2,743	$3,868	$3,713
Operating & Administration Expenses	$265	$547	$526	$530	$843
Subtotal: CDM related operation expenses	**$5,060**	**$13,335**	**$15,205**	**$17,108**	**$16,768**
CDM Program Costs	**$9,880**	**$107,097**	**$161,734**	**$223,597**	**$361,137**
Total CDM related expenditure	**$14,940**	**$120,432**	**$176,938**	**$240,705**	**$377,905**

Actual spending for 2010 will be provided when available through publication in the OPA's 2010 annual report.

b) The estimated total reduction in peak demand and energy consumption in 2010 as a result of the OPA's CDM activities since 2005 is 1,105 MW and 2,170 GWh, as detailed in Tables 1 and 2 below.

Table 1 – Savings from OPA Programs 2005-2010 (Peak)*

Implementation	Net Annual Peak Demand Savings - Generator Level - (MW)					
Year	2005	2006	2007	2008	2009	2010
2005	n/a	n/a	n/a	n/a	n/a	n/a
2006		318	20	20	20	20
2007			602	199	192	192
2008				752	106	106
2009					675	146
2010						643
	0	**318**	**622**	**971**	**992**	**1,105**

* This table does not include savings from other sources such as government programs and policy tools which contribute to the Province's overall conservation targets. Please see the response to GEC Interrogatory 11, at Exhibit I-2-11 for total conservation savings (peak) achieved from all sources since 2005.

Table 2 – Savings from OPA Programs 2005-2010 (Energy)*

Implementation	Net Annual Energy Savings - Generator Level (GWh)					
Year	2005	2006	2007	2008	2009	2010
2005	n/a	n/a	n/a	n/a	n/a	n/a
2006		405	405	405	405	70
2007			498	425	415	415
2008				418	392	391
2009					629	537
2010						756
	0	**405**	**903**	**1,248**	**1,842**	**2,170**

* This table does not include savings from other sources such as government programs and policy tools which contribute to the Province's overall conservation targets.

This estimate is based on final results from OPA funded CDM programs implemented in 2006-2009 (there were no programs in 2005) and an outlook for 2010 programs that the OPA developed in July 2010. All savings are net savings at the generator level (i.e. including avoided transmission and distribution losses).

POLLUTION PROBE INTERROGATORY 8

QUESTION

Issue 2.0 (particularly Issues 2.1, 2.3, and 2.5)

8. Ref: Exhibit B, Tab 2, Schedule 1, pg. 14.

For each of the OPA's 2011 to 2014 CDM programs, please provide the date(s) when the OPA will receive preliminary and/or final evaluation reports with respect to the actual free rider rates for each program.

RESPONSE

Evaluation reports, which include free rider rate results, are prepared on an annual basis. The OPA expects to receive completed evaluation reports containing program implementation results for the previous calendar year in the fall. For example, evaluation reports for program results achieved in 2011 are expected in the fall of 2012.

POLLUTION PROBE INTERROGATORY 9

QUESTION

Issue 3.0 (particularly Issues 3.1. 3.3, and 3.5)

9. Ref: Exhibit B, Tab 3, Schedule 1, pgs. 22 & 23

For each of the OPA's 12 CHP contracts which were in commercial operation as of June 30, 2010, please state their:

a) "All in Customer Payments" per MWh in 2010; and

b) the assumed annual capacity factors used to calculate each of the "All in Customer Payments".

Please state the average annual HOEP and gas commodity costs used by the OPA to calculate the "All in Customer Payments".

To protect the privacy of the relevant CHP companies, each of the 12 contracts can be assigned randomly to and identified by a number (e.g. #1, #2).

RESPONSE

a) Payment information for individual contracted facilities could potentially be used to determine commercially sensitive information regarding OPA counterparties. Therefore, the "All in Customer Payments" provided is an aggregate value based on the weighted average of the "All in Customer Payments" for each individual facility. The “All in Customer Payments” expressed on a per MWh basis for the OPA’s CHP contracted facilities in 2010 was $96/MWh.

In order to calculate the “All in Customer Payments” the OPA used the following formula:

All in Customer Payments = [Sum of (Actual production in each hour X HOEP in each hour) + OPA contract payments]/Total actual production

This formula captures most of the variable costs paid for the CHP contracted facilities which are typically paid for through IESO revenues. The HOEP used was the hourly HOEP corresponding to the actual operation of the facility.

b) The assumed capacity factor, by nature of the calculation for the All in Customer Payments, is the actual capacity factor of the facilities and therefore was not assumed and cannot be disclosed as it would reveal the identity of each individual facility. The gas commodity costs are not relevant given the calculation methodology.

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POLLUTION PROBE INTERROGATORY 10

QUESTION

Issue 3.0 (particularly Issues 3.1. 3.3, and 3.5)

10. Ref: Exhibit B, Tab 3, Schedule 1, pgs. 22 & 23

For each of the OPA's natural gas-fired combined-cycle contracts that were in commercial operation in 2010, please state their:

a) "All in Customer Payments" per MWh in 2010; and
b) the asswned annual capacity factors used to calculate each of the "All in Customer Payments".

Please state the average annual HOEP and gas commodity costs used by the OPA to calculate the "All in Customer Payments".

To protect the privacy of the relevant power companies, each of the contracts can be assigned randomly to and identified by a number.

RESPONSE

Providing payment information for individual contracted facilities could potentially be used to determine commercially sensitive information regarding OPA counterparties. Therefore, the "All in Customer Payments" provided is an aggregate value based on the weighted average of the "All in Customer Payments" for each individual facility. The “All in Customer Payments” expressed on a per MWh basis for the OPA’s Combined Cycle contracted facilities in 2010 was 95 $/MWh.

In order to calculate the “All in Customer Payments” the OPA used the following formula:

All in Customer Payments = [Sum of (actual production in each hour X HOEP in each hour) + OPA contract payments]/Total actual production

This formula captures most of the variable costs paid for the CHP contracted facilities which are typically paid for through IESO revenues. The HOEP used was the hourly HOEP corresponding to the actual operation of the facility in each hour.

The assumed capacity factor, by nature of the calculation for the “All in Customer Payments”, is the actual capacity factor of the facilities and therefore was not assumed and cannot be disclosed as it would reveal the identity of each individual facility. The gas commodity costs are not relevant given the calculation methodology.

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POLLUTION PROBE INTERROGATORY 11

QUESTION

Issue 3.0 (particularly Issues 3.1. 3.3, and 3.5)

11. Ref: Exhibit B, Tab 3, Schedule 1, pgs. 5 & 18

Please provide the OPA's schedule for implementing its CHP standard offer program.

RESPONSE

The OPA’s schedule for implementing the CHP standard offer program was initially posted on the OPA’s website in mid-January 2011. The schedule is expected to be modified throughout the Clean Energy Standard Offer Program ("CESOP") process, of which CHP Standard Offer Program ("CHPSOP") and Energy Recycling Standard Offer Program ("ERSOP") will be subsets. The schedule as of January 31, 2011 was as follows:

Activity	Date
Posting of draft program rules and contract	January 31, 2011
Stakeholder Consultations Stakeholder question and comment period Stakeholder sessions	January 31, 2011 – March 11, 2011 Formal stakeholder sessions to be held in late February – early March. Specific dates for these sessions will be announced in early February.
OPA review of stakeholder comments and submissions & posting of final program documents	March - April
Program launch	Q2 2011

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