NAVIGANT CONSULTING

REGULATED PRICE PLAN – COST TRACKING

MONTHLY VARIANCE EXPLANATION (APR 05 – APR 06)

This document has been prepared at the request of the Ontario Energy Board (OEB, or the "Board"). The Board's objective is to better inform interested stakeholders and consumers about the Regulated Price Plan (RPP) and the factors that have contributed to the difference between the forecast price that RPP consumers currently pay and the actual cost to supply those consumers. An appendix is included which provides monthly values for the key contributing factors. This document is updated on a monthly basis when all of the information becomes available.

All of the statistics presented in this report are taken or derived from publicly available information sources. Neither Navigant Consulting nor the OEB has audited this information. Any revisions by the providers of the actual data will be included in future updates of this report.

This report is available on the Regulated Price Plan (RPP) Web page of the OEB Web site at www.oeb.gov.on.ca (see quick link under "Major Key Initiatives"). Any technical questions regarding this report can be directed to Chris Cincar at 416-440-7696 or Russell Chute at 416-440-7682.

Regulated Price Plan consumers pay a stable price for electricity that was set in advance by the Board. The initial RPP prices went into effect on April 1, 2005 and were to remain in place for a twelve month period (April 2005 through March 2006). During this time the decision was made to extend the initial prices for a thirteenth month through to the end of April 2006. New RPP prices were established by the Board on May 1, 2006.

Under Ontario's current hybrid electricity market structure, there are essentially three sources of supply for the RPP:

1. Generating facilities subject to regulated prices, or under contract to the Ontario Power Authority (OPA) or the Ontario Electricity Financing Corporation (OEFC);
2. Certain Ontario Power Generation (OPG) facilities which are subject to a revenue cap; and
3. Generating facilities that receive the wholesale spot market price.

The first two groups of generating facilities described above (i.e., subject to regulated prices, or under contract, and certain OPG facilities subject to a revenue cap) supply electricity into Ontario's wholesale electricity market and are paid the wholesale spot market price for the electricity they supply to the grid. However, under current regulations, the final revenues for these two groups are different from the spot market price as described below:

- Generating facilities subject to regulated prices or under contract to the OPA or OEFC are paid, or must reimburse, any difference between the average monthly revenue earned for their output on the spot market and their contract price or regulated price. This difference is passed through to consumers through the "Provincial Benefit" (or "Global Adjustment").

> **Example:**
>
> If the spot market price of electricity in a given period was 6 cents per kWh and the average contracted or regulated price (for generating facilities under contract or subject to regulated prices) was 5 cents per kWh, these generating facilities would have to reimburse 1 cent per kWh, on average, to consumers for the electricity they supplied to the Ontario market during that period. This has the effect of reducing their average revenues from 6 cents per kWh to 5 cents per kWh. Conversely, if the spot market price was 4 cents per kWh, these generating facilities would be paid an additional 1 cent per kWh by consumers through the Provincial Benefit to bring their average revenues to 5 cents per kWh.

- Similarly, regulations require that OPG generation facilities subject to a revenue cap must reimburse any difference between the average revenue earned on their generation output and their revenue cap (average of 4.7 cents per kWh) to consumers. This payment is called the "OPG Rebate" (often also referred to as the OPG Non-Prescribed Asset Rebate, or "ONPA rebate"). Under Government regulations at the time the initial RPP price was set, this revenue cap (and rebate) was scheduled to expire on April 30, 2006. However, a new regulation, specifically an Order in Council, has been put in place by the Government to extend the revenue cap for an additional three years. For the first year, May 1, 2006 to April 30, 2007 revenues from the same group of assets will be capped at 4.6 cents per kWh. On May 1, 2007 the cap will return to 4.7 cents per kWh and on May 1, 2008 it will increase to 4.8 cents per kWh. The revenue cap (and rebate) is now set to expire on April 30, 2009. Similar to the initial RPP prices, an estimate of the OPG Rebate continues to be included in the new RPP prices.

The primary effect of these regulations is that the cost of supplying electricity to RPP consumers from the first two sources – 1) generating facilities subject to regulated prices, or under contract to the OPA or OEFC that pay the Provincial Benefit; and 2) certain OPG generation facilities subject to a revenue cap that pay the OPG Rebate – is essentially fixed at a price that was expected to be, and has been, below the average spot price for electricity. This reduces the average cost of supply for all consumers and also reduces consumers' exposure to variability in spot market prices, since the cost of supply from the spot market is not fixed (i.e., changes every hour).

The initial RPP price which went into effect on April 1, 2005 was based on forecasts of many different factors, the most important of which were: 1) the relative amount of electricity coming from each of the three electricity supply sources; and 2) the price of electricity purchased from the spot market.

The actual supply cost for the RPP depends on many factors; the most important of which are the same as those used to forecast the RPP price, namely 1) the relative amount of electricity coming from each of the three supply sources; and 2) the price of electricity purchased from the spot market. If these factors differ from those in the forecast issued by the Board, the *actual* RPP supply cost will differ from the *forecast* RPP supply cost.

The forecast and actual values for the key factors influencing the RPP supply costs are compared below as follows.

1. The first set of values are related to the spot market price of electricity.

2. The second set of values are related to generating facilities subject to regulated prices or under contract to the OPA or OEFC that pay the Provincial Benefit.

3. The third set of values are related to certain OPG facilities subject to a revenue cap that pay the OPG Rebate.

4. Lastly, the difference between the forecast and actual values for the cost of RPP supply and the revenues generated by the RPP are presented. This difference between the forecast and actual RPP supply cost, combined with the difference between the forecast and actual RPP revenue, is what is referred to as the "RPP Variance".

This report is the final in the series that track the variance incurred under the initial RPP prices. Subsequent reports will track the variance against the new RPP prices implemented by the Board on May 1, 2006.

Because the period for which the initial RPP prices apply was extended by one month beyond the original twelve month forecast window of April 2005 through March 2006, no specific forecast parameters are available for April 2006. For the purposes of this report, forecast parameters for April 2006 were taken as the average of the forecast parameters over the previous twelve months. For example, the simple average cost of electricity over the period from April 2005 through March 2006 was forecast to be 5.5 cents per kWh. In this report, the forecast of the simple average spot market price for April 2006 was also taken to be 5.5 cents per kWh (i.e., the average of the initial twelve month period).

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

This comparison shows the cost of electricity purchased from the spot market (without consideration of the Provincial Benefit and OPG Rebate) for a consumer that used the same amount of electricity in each hour. This price would apply to a relatively small subset of consumers.

Simple Average Cost of Electricity

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	5.5 cents per kWh
Actual	6.5 cents per kWh
Percent Difference	18% higher

RPP-Load Weighted Average Spot Market Price

This comparison similarly shows the cost of electricity purchased from the spot market (without consideration of the Provincial Benefit and OPG Rebate). However, in this case, it is for a consumer (e.g., residential) whose usage pattern is the same as the average RPP consumer (higher electricity consumption during the peak periods, such as winter evenings, when prices are higher).

RPP-Load Weighted Average Cost of Electricity

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	6.0 cents per kWh
Actual	7.0 cents per kWh
Percent Difference	16% higher

Natural Gas Price

This comparison shows natural gas prices. Natural gas is the fuel source for generating facilities that set the spot market price for electricity for a portion of hours throughout the day, so natural gas prices have a significant impact on electricity prices. If natural gas prices are higher than forecast, the cost of electricity from these generating facilities and the spot market price of electricity will be higher than forecast.

Higher than forecast natural gas prices have been a primary contributor to higher than forecast electricity prices in the spot market over the past thirteen months. Preliminary analyses show that for every 10% increase in natural gas prices, Ontario electricity spot market prices would increase by approximately 6%.

Natural Gas Prices ($USD)

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	$7.08 / MMBtu
Actual	$8.87 / MMBtu
Percent Difference	25% higher

NB - 1 MMBtu (Million British Thermal Units) ≅ 1.055 GJ (Gigajoules) ≅ 27.5 m3 (cubic meters) of Natural Gas

Weather, Cooling Degree Days (>24°C)

Degree days for a given day represent the number of Celsius degrees that the mean temperature is above or below a given base. This comparison shows the number of cooling degree days above 24°C per month in the city of Toronto (Lester B. Pearson Int'l Airport). If the temperature is less than or equal to 24°C, then the number will be zero. Values above 24°C are used primarily to estimate the cooling requirements of residential consumers. For example, if the mean daily temperature is 30°C, the number of cooling degree days would be 30°C –24°C = 6.

The number of such days since April 1, 2005 has far exceeded normal conditions. This was the primary reason the previous record for electricity consumption (25,414 MW set in August 2002) was exceeded on seven separate occasions this past summer. Only two other years – 2002 and 1988 – have been comparable in terms of heat and humidity since 1970.[1]

Cooling Degree Days (>24 °C)

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	17
Actual	81
Percent Difference	363% higher

Weather, Heating Degree Days (>15°C)

During the winter heating season, the number of heating degree days become an important factor driving electricity demand and spot market prices. Heating degree days are calculated in the same manner as cooling degree days. However, instead of depicting cooling requirements, they offer an indication as to the heating requirements of consumers in Ontario.

This comparison shows the number of heating degree days below 15°C in the city of Toronto (Lester B. Pearson Int'l Airport). If the temperature is higher than or equal to 15°C, then the number will be zero.

[1] 18°C is another common base temperature used to determine cooling degree days. Navigant Consulting and the OEB share the view that 24°C is more representative of when residential consumers use air conditioning.

Heating Degree Days (<15 °C)

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	3,517
Actual	2,894
Percent Difference	18% lower

2. Generating Facilities that Pay the Provincial Benefit

The two main generation supply sources that pay the Provincial Benefit are OPG's nuclear generating stations and OPG's regulated (baseload) hydroelectric generating stations.

OPG Nuclear Output

This comparison shows the output (or production) of OPG's nuclear plants. Overall, the actual amount of electricity produced by these generation facilities is close to their forecast output.

OPG's Nuclear Output

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	50.6 TWh
Actual	49.5 TWh
Percent Difference	2% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Regulated (Baseload) Hydroelectric Output

This comparison shows the amount of electricity produced by OPG's regulated hydroelectric plants (DeCew Falls, Sir Adam Beck, and R.H. Saunders). The output from these facilities is primarily baseload, i.e. they are generally producing electricity all of the time (24 x 7). Overall, the actual output of these generating facilities is close to their forecast output.

OPG's Baseload Hydroelectric Output

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	19.7 TWh
Actual	19.3 TWh
Percent Difference	2% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

Provincial Benefit

This comparison shows the forecast versus actual Provincial Benefit (also referred to as the "Global Adjustment"). The actual Provincial Benefit is higher than forecast, which has helped to mitigate the impact of higher than forecast spot market prices. The forecast value of the Provincial Benefit is already included in the current RPP prices.

Provincial Benefit (Global Adjustment)	
RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	0.23 cents per kWh
Actual	0.68 cents per kWh
Difference	0.45 cents higher

Unlike the spot market price, the Provincial Benefit does not differ based on when a consumer's electricity consumption occurs. In other words, it is the same unit value for all Ontario electricity consumers whether they consume more electricity during "on-peak" (e.g., daytime) periods when spot market prices are higher or they consume more electricity during "off-peak" (e.g., night) periods when spot market prices are lower.

The Provincial Benefit was a charge to consumers of 0.2 cents per kWh and 0.6 cents per kWh in March and April respectively. This is primarily due to lower spot market prices during these two months (4.9 cents per kWh in March and 4.4 cents per kWh in April). These figures can be found in the Appendix of this report.

3. Generating Facilities that Pay the OPG Rebate (or ONPA rebate)

The two supply sources that pay the OPG Rebate are OPG's coal-fired generating plants and OPG's unregulated hydroelectric generating plants.

OPG Coal-fired Output

This comparison shows the output of OPG's coal-fired generating plants. Overall, the actual output of these generators is over 15 percent lower than the Board's forecast.

OPG's Coal Fired Output	
RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	36.2 TWh
Actual	30.0 TWh
Percent Difference	17% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Unregulated (Non-Prescribed) Hydro Electric Output

This comparison shows the output of OPG's unregulated hydroelectric generating facilities. The large majority of this output comes from "peaking" capacity which only tend to operate during periods of high demand. The remainder is "baseload" capacity which is operating more or less continuously all of the time (24 x 7).

The actual output of these generators is lower than the output forecast by the Board due to the limited amount of rainfall experienced this past summer. In terms of the overall electricity supply for RPP consumers, this lower than expected output forced more of the RPP supply to come from more expensive purchases on the spot market (e.g., natural gas-fired generators and electricity imports). The impact is further exacerbated because OPG's unregulated hydroelectric generating facilities contribute to the OPG Rebate. Water levels appear to have returned to normal levels after December with actual output closer to forecast over the last four months.

OPG's Unregulated Hydroelectric Output

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	19.7 TWh
Actual	15.7 TWh
Percent Difference	20% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Rebate (estimated)

This comparison shows the OPG Rebate. The estimated OPG Rebate to date is slightly higher than forecast, which has helped to mitigate the impact of higher than forecast spot market prices. However, the degree to which it has mitigated price impacts is less than would be expected because the amount of supply that pays the OPG Rebate has been less than forecast as illustrated in the two tables above. The forecast value of the OPG Rebate is already included in current RPP prices.

OPG Rebate

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	0.46 cents per kWh
Actual	0.49 cents per kWh
Difference	0.04 cents higher

Under new Government regulations, this revenue cap (and rebate) will be extended for 3 years. Revenues from OPG's non-prescribed assets were limited to 4.7 cents per kWh through April 30, 2006. Under the new regulation revenue from these assets will be limited to 4.6 cents per kWh from May 1, 2006 through April 30, 2007. On May 1, 2007 the cap will return to 4.7 cents per kWh and on May 1, 2008 will increase to 4.8 cents per kWh. The revenue cap (and rebate) is now set to expire on April 30, 2009.

During April 2006, the Independent Electricity System Operator (IESO) distributed the OPG Rebate to consumers based on actual electricity consumption for the first nine months (April to December 2005). The portion of the rebate allocated to RPP consumers, and forwarded to the OPA by the IESO, was less than the estimates previously provided to the Board.

Previous estimates had allocated 100 percent of the RPP portion to the OPA variance account. However, due to Bill 210, some consumers with retail contracts currently pay RPP prices because they had entered into those contracts prior to November 11, 2002 when the electricity price was frozen at 4.3 cents for all low volume consumers. The IESO has forwarded the OPG Rebate for these consumers to the retailer that the consumer had signed a contract with (or the retailer that currently holds the contract).

Most of these consumers assigned their rebates to the retailer under the terms of their original contract whereas other consumers did not. The OPG Rebate for consumers who had assigned the rebate to their retailer will stay with the retailer. For those consumers who did not assign their rebate, the retailer is required to return the rebate to the IESO, and any returned rebates will ultimately be credited to the OPA variance account. Since the majority of the rebates discussed above were in fact signed over to the retailer, only a relatively small portion of the outstanding rebate is likely to be credited back to the OPA.

Consumers who assigned their rebate to their retailer are subject to the same RPP prices as other RPP consumers and therefore still benefit from the inclusion of the OPG Rebate in the RPP prices. However, when the rebate is disbursed by the IESO, the portion of the rebate that would otherwise have been allocated to the OPA variance account for these consumers is distributed to electricity retailers. As a result, the OPG Rebate allocated to the OPA variance account is reduced.

This results in a lower than expected OPG Rebate for RPP consumers, as well as a lower per unit OPG Rebate for RPP consumers relative to non-RPP consumers. Taking into account an estimate of the portion of the rebate likely to be returned to the OPA from the retailers, the difference is estimated to be roughly 0.07 cents per kWh or $54 million.

Impact of Assignment of Rebate to Retailer

RPP Year I (Apr 1, 2005 through Apr 30, 2006)		
Total	$54	million
Unit Value	-0.07	cents per kWh

This shortfall will be included in the final variance settlement factor, for consumers that leave the RPP, and in the variance recovery factor which is taken into consideration when a determination is made if RPP prices need to be reset for consumers remaining on the RPP.

4. RPP Supply Costs and Revenues

The RPP supply cost represents the cost and amount of electricity for RPP consumers associated with each of the three sources of generation supply discussed above (see page 1) and is calculated as the spot market price of electricity, less the Provincial Benefit and OPG Rebate.

The RPP revenues represent the total revenues generated from the two tiered pricing structure of 5.0 cents per kWh (for consumption below the tier threshold) and 5.8 cents per kWh (for consumption above the tier threshold).

The difference between the forecast and the actual RPP supply cost is accumulated and tracked in a variance account (held by the OPA) to be either *credited* to RPP consumers (if a positive variance) or *charged* to RPP consumers (if a negative variance).

RPP Unit Supply Cost

The RPP unit supply cost is higher than forecast, largely due to: 1) higher than forecast spot market prices; and 2) lower than forecast OPG unregulated hydroelectric output (which was replaced by more expensive purchases from the spot market). Higher than expected natural gas prices were a major contributor to the first factor which, in turn, exacerbated the impact of the second factor.

RPP Unit Supply Cost

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	5.3 cents per kWh
Actual	5.9 cents per kWh
Percent Difference	11% higher

The RPP unit supply cost shown above reflects the impact of allocating a portion of the RPP share of the OPG Rebate to electricity retailers.

RPP Total Supply Cost

For the same reasons as given above, the RPP total supply cost is higher than forecast.

RPP Total Supply Cost

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	$4,300 million
Actual	$4,760 million
Percent Difference	11% higher

RPP Unit and Total Revenues

The actual RPP revenue was roughly 1% higher than forecast. This offsets a portion of the higher than forecast supply cost. A more detailed discussion of the RPP unit and total revenues is available in the Appendix section of this report.

RPP Variance[2]

The RPP Variance represents the difference between the revenues collected from RPP consumers and the cost to supply RPP consumers (i.e., RPP supply cost).

Although the forecast RPP variance at the end of the RPP Year (March 30, 2006[3]) was expected to be zero, forecast monthly variations in RPP consumption, spot market prices and the relative mix of generation supply from the three sources led to relatively small positive or negative variances at different times throughout the year in the forecast.

The following comparison shows the forecast and actual RPP variance as of April 30, 2006.

RPP Variance

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	$0 million
Actual	-$417 million

The negative $417 million RPP variance corresponds to the "Net Variance Account Balance" identified on the OEB's Final RPP Variance Settlement Amount web page.[4] This value is taken to be the amount outstanding after the estimated accrued OPG Rebate (attributable to RPP consumers) is taken into account. The new RPP price effective May 1, 2006 included a forecast of the outstanding variance as of April 30, 2006 of $377 million. The difference between the forecast and actual RPP year ending variance will be included in the variance recovery factor when a determination is made if RPP prices need to be reset.

As explained previously in the section of this report discussing the OPG Rebate, the lower than estimated OPG Rebate increased the variance account balance by roughly $54 million. This impact has been mitigated to a certain degree by milder than expected weather during March and April, which resulted in lower than expected wholesale spot market electricity prices. As a result, the difference between the variance of $417 million and the forecast variance of $377 million used to set the new RPP prices is $40 million.

[2] The RPP variance includes interest incurred by the OPA for balances held in the variance account, as required by the Board's RPP Manual. The new price set by the Board on May 1, 2006 will take into account any accumulated interest on the balance carried from the previous year.

[3] As per the Board Notice issued on November 2, 2005, the RPP year-end was extended by one month to April 30, 2006, so that the changes to the RPP prices are synchronized with the Board approved distribution rate adjustments as well as the seasonal changes to the residential tier thresholds.

[4] http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_variance.htm

Finally, it is important to place the current variance balance in context. While the price forecast is based on "normal" weather conditions, the summer of 2005 was, on average, the hottest and most humid summer for Ontario in recent history as explained above. The period from June through October 2005 accounts for approximately 95 percent of the current RPP variance.

APPENDIX A – KEY VARIANCE DRIVERS, MONTHLY VALUES

Presented in this appendix are the monthly values for the factors discussed in the body of this document. As well, two additional summary tables are provided for the output from Lennox Generating Station and RPP total demand which are not addressed previously.

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

cents per kWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	5.5	6.0	5.7	5.3	5.5	5.5	5.5
Actual	7.3	5.6	4.8	4.9	6.7	4.4	6.5
% Difference	32%	-7%	-16%	-7%	21%	-21%	18%

RPP Load Weighted Average Spot Market Price[5]

cents per kWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	6.0	6.4	6.1	5.6	6.0	6.0	6.0
Actual	7.8	6.0	4.7	5.0	7.1	4.6	7.0
% Difference	31%	-7%	-23%	-11%	19%	-24%	16%

RPP Demand

TWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	56.4	6.1	6.6	5.7	74.8	6.2	81.0
Actual	55.6	6.9	6.2	6.8	75.5	5.6	81.1
Difference	-1%	12%	-5%	19%	1%	-10%	0.1%

Natural Gas Price

$/MMBtu	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	$6.92	$7.65	$7.64	$7.42	$7.08	$7.08	$7.08
Actual	$9.43	$8.82	$7.69	$6.81	$9.01	$7.19	$8.87
% Difference	36%	15%	1%	-8%	27%	2%	25%

[5] Actual values are calculated based on LDC reported monthly RPP revenues and costs for RPP supply which was provided by the IESO. The LDCs report these RPP revenues and costs before month-end, and are based on an estimate for the current month plus any reconciliation required for prior submissions. The forecast values were developed based on an estimate of the consumption pattern for RPP consumers.

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Weather, Cooling Degree Days (> 24 °C)

> 24 °C	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Normal	17	0	0	0	17	0	17
Actual	81	0	0	0	81	0	81
% Difference	363%	--	--	--	363%	--	363%

Weather, Heating Degree Days (< 15 °C)

< 15 °C	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Normal	1,535	660	577	479	3,251	266	3,517
Actual	1,305	442	520	428	2,694	200	2,894
% Difference	-15%	-33%	-10%	-11%	-17%	-25%	-18%

2. Generators that Pay the Provincial Benefit

The tables below show the total output from OPG's regulated generation facilities. However the regulation specifies that any output above a threshold of 1,900 MW in any given hour is eligible to receive the spot price, and hence does not contribute to the Provincial Benefit.

OPG Nuclear Output

TWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	33.6	4.6	4.1	4.4	46.7	3.9	50.6
Actual	33.2	4.1	4.3	4.4	45.9	3.6	49.5
% Difference	-1%	-11%	5%	-1%	-2%	-8%	-2%

OPG Regulated Hydroelectric Output

TWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	13.7	1.5	1.4	1.6	18.2	1.5	19.7
Actual	13.3	1.5	1.4	1.6	17.8	1.5	19.3
% Difference	-3%	-3%	0%	5%	-2%	-3%	-2%

Provincial Benefit (or "Global Adjustment")

cents per kWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	0.2	0.4	0.2	0.1	0.2	0.2	0.2
Actual	1.1	0.2	(0.4)	(0.2)	0.8	(0.6)	0.7
Difference	0.9	(0.2)	(0.7)	(0.3)	0.5	(0.8)	0.4

3. Generators that Pay the OPG Rebate (or "ONPA rebate")

The tables below show the total output from OPG's non-prescribed generation facilities. However, under the existing regulation, 15 percent of the total output from these facilities is not subject to the cap (and rebate).

OPG Coal-fired Output

TWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	23.9	3.3	3.0	3.1	33.4	2.8	36.2
Actual	21.6	2.7	2.3	2.1	28.7	1.3	30.0
% Difference	-10%	-18%	-24%	-33%	-14%	-55%	-17%

OPG Unregulated (Non-prescribed) Hydroelectric Output

TWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	14.1	1.3	1.2	1.5	18.2	1.5	19.7
Actual	10.0	1.3	1.3	1.3	13.9	1.9	15.7
% Difference	-29%	1%	2%	-13%	-24%	23%	-20%

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Rebate

cents per kWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	0.4	0.7	0.5	0.5	0.5	0.5	0.5
Actual	0.7	0.3	0.1	0.1	0.5	0.0	0.5
Difference	0.2	(0.4)	(0.4)	(0.4)	0.1	(0.4)	0.0

4. RPP Unit and Total Revenues

The RPP unit revenue is calculated as the weighted average price of electricity consumed by RPP consumers at the two tiered prices (5.0 and 5.8 cents per kWh). The actual unit revenue roughly 1% higher than forecast.

cents per kWh	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	5.4	5.1	5.2	5.2	5.3	5.3	5.3
Actual	5.4	5.3	5.3	5.3	5.4	5.3	5.4
% Difference	1%	4%	3%	4%	1%	0%	1%

The differential between *forecast* and *actual* RPP demand combined with the differential between *forecast* and *actual* RPP unit revenues results in a slight difference between the *forecast* and *actual* total RPP revenue.

million $	Apr-05 to Dec-05	Jan-06	Feb-06	Mar-06	RPP Year I	Apr-06	RPP to Date
Forecast	$3,021	$314	$343	$294	$3,970	$330	$4,300
Actual	$2,996	$367	$333	$363	$4,059	$299	$4,358
% Difference	-1%	17%	-3%	24%	2%	-9%	1%