REGULATED PRICE PLAN – COST TRACKING

MONTHLY VARIANCE EXPLANATION (MAY 06 – JULY 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 remained in place for a thirteen month period (April 2005 through April 2006). New RPP prices were established by the Board on May 1, 2006. This report will focus on the ability of the new RPP prices to recover the cost of supplying RPP consumers, as well as the extent to which the new prices recover the outstanding variance as of April 30, 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:**
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> 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 4.6 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"). 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[1]. 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 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 new RPP prices which went into effect on May 1, 2006 were based on forecasts of many different factors, the most important of which were: 1) the relative amount of electricity coming

[1] Output sold by OPG through the OPA Pilot Auction (PA) is excluded from the 4.6 cent per kWh cap and instead is subject to a higher revenue cap of 5.1 cents per kWh. On May 1, 2007 the cap will rise to 4.7 cents per kWh and on May 1, 2008 it will increase again to 4.8 cents per kWh.

from each of the three electricity supply sources; and 2) the price of electricity purchased from the spot market; and 3) the outstanding variance at the end of the initial RPP period.

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 outstanding variance as of April 30, 2006.
2. The second set of values are related to the spot market price of electricity.
3. The third 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.
4. The fourth set of values are related to certain OPG facilities subject to a revenue cap that pay the OPG Rebate.
5. 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".

1. Outstanding Variance Recovery

The RPP prices that came into effect on May 1, 2006 include a variance recovery factor that was set to recover the expected outstanding variance as of April 30, 2006, reducing it to zero over the twelve month period from May 2006 through April 2007.

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.

The forecast of the outstanding variance as of April 30, 2006 upon which the variance recovery factor is based 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 had assigned their rebates to the retailer under the terms of the original contract. As such, only a relatively small portion of the outstanding OPG rebate forwarded by the IESO to retailers is likely to be credited back to the OPA.

As a result, the outstanding variance as of April 30, 2006 was higher than originally anticipated when the new RPP prices were announced. The magnitude of this impact was somewhat mitigated by lower than expected prices and warmer temperatures in March and April 2006. However, the net effect was that the outstanding negative variance as of April 30, 2006 was $38 million greater than forecast. Hence, the variance recovery factor included in the new RPP prices may not be sufficient to recover all of the outstanding variance over the period from May 2006 through April 2007.

Outstanding Variance from Initial RPP Period

RPP Year I (Apr 1, 2005 through Apr 30, 2006)		
Forecast	-$377	million
Actual	-$415	million
Percent Difference	10%	higher

As of May 1, 2006, due to recent revisions made by the Government to the applicable Order-in-Council (OIC), retailers are no longer able to claim the rebate for those consumers who are still under contract with the retailer but pay RPP prices. Hence, there should be no further impact on the variance account for payment related to the period after May 1, 2006.

For the period from January through April 30, 2006 it is assumed that the "leakage" led to 87% of the actual OPG Rebate being forwarded to the RPP customers.

2. 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. Actual spot market prices were lower than forecast from May through July due largely to lower than forecast natural gas prices, lower RPP demand and higher than forecast OPG nuclear output.

Simple Average Cost of Electricity

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	5.9	cents per kWh
Actual	4.8	cents per kWh
Percent Difference	20%	lower

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). The actual RPP load-weighted spot market price is lower than forecast for the same reasons as described above for the simple average spot market price.

RPP-Load Weighted Average Cost of Electricity

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	6.5 cents per kWh
Actual	5.2 cents per kWh
Percent Difference	19% lower

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 were a primary contributor to higher than forecast electricity prices in the spot market during the initial RPP period. 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 in May through July 2006 were lower than forecast. This contributed to the lower than forecast spot market prices.

Natural Gas Prices ($USD)

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	$7.67 / MMBtu
Actual	$6.24 / MMBtu
Percent Difference	19% lower

NB - 1 MMBtu (Million British Thermal Units) ≅ 1.055 GJ (Gigajoules) ≅ 27.5 m^3 (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.[2] 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.

During the initial RPP period, the number of such days far exceeded normal conditions. During the three months of the current RPP period, weather has also played a role as the level of cooling degree days was above normal.

Cooling Degree Days (>24 °C)

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	12
Actual	39
Difference	27 higher

Weather, Heating Degree Days (>15°C)

During the winter heating season, the number of *heating* degree days replaces *cooling* degree days as 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. The number of heating degree days was lower than expected. This appears to coincide with a higher number of cooling degree days than expected as discussed above.

Heating Degree Days (<15 °C)

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	102
Actual	69
Difference	33 lower

3. 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.

[2] 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.

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 higher than their forecast output.

OPG's Nuclear Output

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	10.5	TWh
Actual	11.9	TWh
Percent Difference	13%	higher

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 lower than the forecast by the Board.

OPG's Baseload Hydroelectric Output

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	5.0	TWh
Actual	4.4	TWh
Percent Difference	12%	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 forecast value of the Provincial Benefit is already included in the current RPP prices.

Provincial Benefit (Global Adjustment)

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	0.3	cents per kWh
Actual	-0.2	cents per kWh
Difference	0.5	cents lower

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 continues to be a charge to consumers as it has been since February 2006. This is primarily due to low spot market prices.

4. 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. Actual output from these generators was slightly higher than the Board's forecast for May through July 2006. The output from OPG's coal-fired facilities is strongly correlated with demand in Ontario. Higher demand implies greater output from OPG's coal-fired facilities, or contrary, lower demand implies less output from the same facilities.

OPG's Coal Fired Output

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	6.6 TWh
Actual	6.9 TWh
Percent Difference	5% higher

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 for the current period.

OPG's Unregulated Hydroelectric Output

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	4.2 TWh
Actual	3.3 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 for May through July 2006 is lower than forecast, a result of lower than forecast spot market prices. The forecast value of the OPG Rebate is already included in current RPP prices.

OPG Rebate

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	0.5 cents per kWh
Actual	0.2 cents per kWh
Difference	0.3 cents lower

Under new Government regulations, this revenue cap (and rebate) was extended for 3 years, with revenue from these assets currently limited to 4.6 cents per kWh from May 1, 2006 through April 30, 2007. On May 1, 2007 the cap will increase to 4.7 cents per kWh and on May 1, 2008 will increase again to 4.8 cents per kWh for the subsequent 12 month period.

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 5.8 cents per kWh (for consumption below the tier threshold) and 6.7 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 lower than forecast for May through July 2006.

RPP Unit Supply Cost

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	5.6 cents per kWh
Actual	5.3 cents per kWh
Percent Difference	6% lower

The RPP unit supply cost presented above excludes the variance recovery factor.

RPP Total Supply Cost

The actual *total* RPP supply cost is lower than forecast. This is a result of lower than forecast demand as well as lower than forecast RPP *unit* supply cost.[3]

[3] The RPP total supply cost also includes the stochastic adjustment factor, which is not included in the unit supply cost. For an explanation of the stochastic adjustment factor, please see the RPP Price Report issued on April 12, 2006 on the Board's website at http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_baseline.htm.

RPP Total Supply Cost

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	$1,063	million
Actual	$949	million
Percent Difference	11%	lower

RPP Unit and Total Revenues

The RPP unit revenue was roughly 1% lower than forecast. This is a result of a higher percentage of consumption at the lower tier price than originally forecast.

RPP Unit Revenues

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	5.8	cents per kWh
Actual	5.7	cents per kWh
Percent Difference	1%	lower

The actual RPP revenue was roughly 4% lower than forecast; a combination of lower than forecast RPP demand and lower than forecast unit RPP revenue.

RPP Total Revenues

RPP Year II (May 1, 2006 through July 31, 2006)		
Forecast	$1,073	million
Actual	$1,028	million
Percent Difference	4%	lower

RPP Variance[4]

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).

The RPP prices that came into effect on May 1, 2006 include a variance recovery factor that was set to recover the expected outstanding variance as of April 30, 2006 to zero over the twelve month period from May 2006 through April 2007.

As mentioned in Section 1, the outstanding variance from the initial RPP period as of April 30, 2006 was negative $415 million; $38 million higher than forecast.

[4] The RPP variance includes interest incurred by the OPA for balances held in the variance account, as required by the Board's RPP Manual.

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Outstanding Variance from Initial RPP Period

RPP Year I (Apr 1, 2005 through Apr 30, 2006)	
Forecast	-$377 million
Actual	-$415 million
Percent Difference	10% higher

The variance recovery factor of 0.5 cents per kWh included in the new RPP prices recovered $90 million of the outstanding variance for May through July 2006, which is $3 million less than forecast.

Outstanding Variance Recovery

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	$93 million
Actual	$90 million
Percent Difference	3% lower

Although the forecast RPP variance at the end of the RPP Year (April 30, 2007) is expected to be zero, forecast monthly variations in RPP consumption, spot market prices and the relative mix of generation supply from the three sources lead 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 July 31, 2006 exclusive of any outstanding variance from the initial RPP period and any variance recovered by RPP prices during the May through July 2006 period.

RPP Variance - Year II Only

RPP Year II (May 1, 2006 through July 31, 2006)	
Forecast	$10 million
Actual	$79 million

Taking into account all of the above factors – the outstanding variance balance as of April 30, 2006, the amount recovered through the variance recovery factor incorporated into the RPP prices and the variance accumulated during the first two months of the current period - the total variance accumulated in the OPA variance account is negative $267 million. Compared to the forecast total variance of negative $294 million, this yields an unexpected variance of $27 million (i.e., the negative variance balance as of July 31, 2006 was $27 million less than it was expected to be under the forecast used to set the RPP prices) .

RPP Variance - Overall

RPP Year II (Apr 1, 2005 through July 31, 2006)	
Forecast	-$294 million
Actual	-$267 million

The negative $267 million RPP variance corresponds to the "Net Variance Account Balance" identified on the OEB's Final RPP Variance Settlement Amount web page.[5] This value is taken to be the amount outstanding after the estimated accrued OPG Rebate (attributable to RPP consumers) is taken into account. The difference between the forecast and actual RPP year ending variance will be included in the variance recovery factor when prices are reset.

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

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, one additional summary table is provided for RPP total demand which was not previously discussed in this report.

April 2006 is included as a stand alone month because, following the issuance of the initial Board forecast, year one of the RPP was extended by the Board for one month to synchronize the RPP price change with changes to distribution rates. As a result, April 2006 was not taken into account in the initial Board forecast.

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

cents per kWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	5.5	5.5	4.8	5.6	7.3	5.9
Actual	6.7	4.4	4.6	4.6	5.1	4.8
% Difference	21%	-21%	-4%	-18%	-31%	-20%

RPP Load Weighted Average Spot Market Price[6]

cents per kWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	6.0	6.0	5.2	6.1	8.1	6.5
Actual	7.1	4.6	5.3	4.8	5.6	5.2
% Difference	19%	-24%	2%	-21%	-31%	-19%

RPP Demand

TWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	74.8	6.2	5.9	6.0	6.6	18.5
Actual	75.5	5.6	5.6	5.9	6.4	17.9
Difference	1%	-10%	-5%	-2%	-2%	-3%

Natural Gas Price

$/MMBtu	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	$7.08	$7.08	$7.51	$7.67	$7.82	$7.67
Actual	$9.01	$7.19	$6.43	$6.29	$5.99	$6.24
% Difference	27%	2%	-14%	-18%	-23%	-19%

[6] 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.

Weather, Cooling Degree Days (> 24 °C)

> 24 °C	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Normal	17	0	0	2	10	12
Actual	81	0	6	7	25	39
% Difference	363%	--	N/A	234%	168%	N/A

Weather, Heating Degree Days (< 15 °C)

< 15 °C	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Normal	3,251	266	86	15	1	102
Actual	2,694	200	63	5	0	69
% Difference	-17%	-25%	-26%	-65%	-100%	-32%

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	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	46.7	3.9	3.6	3.5	3.4	10.5
Actual	45.9	3.6	3.7	4.0	4.2	11.9
% Difference	-2%	-8%	1%	14%	26%	13%

OPG Regulated Hydroelectric Output

TWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	18.2	1.5	1.7	1.6	1.7	5.0
Actual	17.8	1.5	1.5	1.4	1.6	4.4
% Difference	-2%	-3%	-13%	-16%	-7%	-12%

Provincial Benefit (or "Global Adjustment")

cents per kWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	0.2	0.2	(0.3)	0.2	1.1	0.3
Actual	0.8	(0.6)	(0.3)	(0.3)	(0.1)	(0.2)
Difference	0.5	(0.8)	(0.0)	(0.4)	(1.2)	(0.6)

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 revenue cap (and rebate).

OPG Coal-fired Output

TWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	33.4	2.8	2.0	2.1	2.4	6.6
Actual	28.7	1.3	1.7	2.3	2.8	6.9
% Difference	-14%	-55%	-14%	10%	16%	5%

OPG Unregulated (Non-prescribed) Hydroelectric Output

TWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	18.2	1.5	1.7	1.4	1.1	4.2
Actual	13.9	1.9	1.5	1.0	0.8	3.3
% Difference	-24%	23%	-9%	-28%	-26%	-20%

OPG Rebate

cents per kWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	0.5	0.5	0.2	0.4	0.8	0.5
Actual	0.5	0.0	0.1	0.1	0.3	0.2
Difference	0.1	(0.4)	(0.1)	(0.3)	(0.5)	(0.3)

4. RPP Unit and Total Revenues

The RPP unit revenue for May 2006 onwards is calculated as the weighted average price of electricity consumed by RPP consumers at the two tiered prices (5.8 and 6.7 cents per kWh) less the variance recovery factor of 0.5 cents per kWh. The actual unit revenue was roughly 1% lower than forecast.

cents per kWh	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	5.3	5.3	5.8	5.8	5.8	5.8
Actual	5.4	5.3	5.7	5.7	5.8	5.7
% Difference	1%	0%	-2%	-1%	-1%	-1%

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

million $	RPP Year I	Apr-06	May-06	Jun-06	Jul-06	RPP II to Date
Forecast	$3,970	$330	$343	$349	$382	$1,073
Actual	$4,059	$299	$318	$338	$371	$1,028
% Difference	2%	-9%	-7%	-3%	-3%	-4%