# OTHER REVENUES – REGULATED HYDROELECTRIC

## 1.0 PURPOSE

This section explains the treatment in this Application of revenues other than energy production ("other revenues") from OPG's regulated hydroelectric generating facilities.

## 2.0 OVERVIEW

Some of OPG's regulated hydroelectric generating facilities are a source of other revenues. These include revenues associated with ancillary services, such as the provision of black start capability, operating reserve, reactive support/voltage control service, and automatic generation control ("AGC") as well as other sources not specifically defined under the category of ancillary services, including congestion management settlement credits ("CMSC"), segregated mode of operation ("SMO"), and water transactions. This section provides a description of these sources of other revenues, along with proposals for their treatment in both the interim period and the test period.

Other revenues associated with ancillary services were forecast for the interim period and the test period. The forecast revenues were included as an offset in the calculation of the revenue requirement for the regulated facilities. These ancillary services are integral to the operation of OPG's prescribed assets. Differences between forecast and actual revenues associated with these ancillary services, qualify for inclusion within the interim variance account, as per subsection 5 (1) (c) of O. Reg. 53/05. For information on existing and proposed variance accounts, see Exhibit J.

Forecast revenues from sources of other revenues that are not associated with ancillary services (CMSC, SMO, and water transactions) were not included in the calculation of the revenue requirement during the interim and test periods because revenues associated with these activities are difficult to forecast accurately. Further, these activities are not covered by the variance accounts, established pursuant to section 5 of O. Reg. 53/05. For these reasons, along with the high degree to which these activities are integrated with the operation of the electricity market and OPG's need for market-based incentives in respect of these activities, OPG has proposed different regulatory treatments for the revenues from these activities for both the interim and test periods. The proposed treatments for these categories of other revenues are set out below.

## 3.0 ANCILLARY SERVICES

There are three contract based ancillary services. The services of black start capability and AGC are purchased by the IESO through competitive tendering processes. The service of reactive support/voltage control is contracted by the IESO through a negotiated process and is not competitively tendered. Suppliers of these services receive compensation for costs associated with being available to provide this service, out-of-pocket costs, opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable. The cost of these services is passed on to consumers by the IESO through monthly uplift charges[1].

In contrast, operating reserve is a market based ancillary service that is jointly optimized with the energy market. Although operating reserve is not a contract based ancillary service, under Part 5 (a) of OPG's Generator Licence (EG-2003-0104), OPG is required to offer operating reserve at a price that does not exceed a bid cap. This bid cap is negotiated as part of an agreement between OPG and the IESO and provides for the recovery of costs similar to those described above.

### 3.1 Ancillary Service - Black Start Capability

Black start capability, as defined in the Market Rules, means the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid. The IESO, in recognition of this being a critical service for purposes of system recovery, security and reliability, procures this capability from certain generation facilities that have the capacity to meet this need in the event that such a need arises.

[1] Monthly uplift charges are primarily comprised of the costs for black start, reactive support / voltage support, and AGC which are purchased under contract to maintain the reliability of the Ontario power network.

Sir Adam Beck II and R.H. Saunders are the two OPG facilities currently under contract with the IESO for black start capability.

In forecasting black start capability revenues for the interim period, OPG started with the contracts as they existed in June 2004 and then took into account anticipated changes in the subsequent contract term, which commenced on November 1, 2005 and expired on April 30, 2007. That contract was renewed under the same terms and conditions for an additional 18 month period, effective May 1, 2007 and provided for a five percent increase in revenues for the new term. In forecasting black start capability revenues for the test period, OPG assumed the existing contract would be extended for another 18 month term with similar terms and conditions. This would also apply to the period from November 1, 2008 to May 1, 2010.

### 3.2 Ancillary Service - Reactive Support/Voltage Control Service

Under the Market Rules, reactive support service means a service provided by a market participant so as to allow the IESO to maintain the reactive power levels required by the IESO-controlled grid. Similarly, voltage control service means a service provided by a market participant so as to allow the IESO to maintain voltage levels required by the IESO-controlled grid. Collectively, these are referred to in this Application as reactive support/voltage control service.

In forecasting revenues for the interim period, OPG based its forecast on the actual revenues achieved for a historical period which was representative of operations for 2005. A three percent escalation factor representing inflation was included for 2006.

OPG and the IESO negotiated a Reactive Support/Voltage Control Service Agreement effective from July 1, 2006 until December 31, 2007. In forecasting revenues for 2007, 2008 and 2009, updated information from the existing contract and a three percent escalation factor representing inflation per year was applied.

The nuclear assets also receive revenues associated with the provision of reactive support/voltage control service. These revenues are presented in Ex. G2-T1-S1.

### 3.3 Ancillary Service - Automatic Generation Control

As defined in the Market Rules, AGC means the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between load and the output from generation facilities.

For AGC, OPG's 2005 forecast was based on the average of actual station AGC revenues from April 2004 to June 2004. This period was selected as it represented the going-forward revenues anticipated in the contract executed in January 2004. Forecast contract revenues were increased in 2006 by three percent for inflation. The 2006 actual revenues were based on the AGC agreement between OPG and the IESO that was effective from November 1, 2005 to April 30, 2007.

Forecasts for 2008 and 2009 were based on the 2007 forecast plus an allowance for inflation of 3 percent. A new contract for AGC was executed with the IESO and became effective May 1, 2007 with an expiration date of April 30, 2009.

### 3.4 Ancillary Service - Operating Reserve

Operating reserve refers to the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingency. As such, operating reserve can either be generating capacity, or demand that can be reduced on short notice, by the IESO.

The IESO establishes separate prices for the energy market and the operating reserve markets. The IESO jointly optimizes these two markets to produce dispatch instructions and prices intended to result in the most cost-effective overall solution for the market. OPG is required to offer operating reserve from all available units under Part 5 (a) of its Generator Licence (EG-2003-0104). Operating reserve revenue consists of general operating reserve ("general OR") and congestion management settlement credits operating reserve ("CMSC

OR"). Because it is a market-based ancillary service, the amount of general OR accepted depends on OPG's operating reserve offers and market conditions. The amount of CMSC OR depends on the difference between the IESO market schedule and the IESO dispatch schedule. Further discussion of CMSC is provided in section 6.0, below.

For 2005 and 2006, the OR revenue forecasts were based on actual revenues with an adjustment for forecast production. Congestion management settlement credits operating reserve payments are not predictable and therefore revenues were left unadjusted. For 2007, 2008 and 2009, the OR revenue forecasts are based on 2006 actual revenues with an adjustment for forecast production and an allowance for inflation of three percent per year.

## 4.0 SEGREGATED MODE OF OPERATION

Segregated mode of operation is defined by the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity or physical services to such neighbouring control area. The generating facilities will thus be isolated into the neighbouring control area when in segregated mode.

Segregated mode of operation transactions are accommodated by segregating up to eight units (or two banks of four units) of production from R.H. Saunders to Hydro-Québec's control area at St. Lawrence Transformer Station. When this occurs, these Saunders units are no longer connected to the Ontario IESO-controlled grid (although, they are recallable by the IESO for Ontario system need) and do not participate in the Ontario market. Rather, these units are now connected to the Hydro-Québec system and receive revenues from markets outside Ontario.

Segregated mode of operation allows OPG to facilitate market activity on its own behalf or on behalf of other market participants within the framework of the Market Rules. Prior to entering into a SMO configuration, OPG must seek approval from the IESO which can be refused or revoked and terminated at any time.

Segregated mode of operation is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods. The economic drivers used in deciding whether or not to engage in an SMO transaction are the forecast market prices in Ontario and surrounding markets.

Segregated mode of operation can provide several benefits to Ontario, such as:

(1) Providing a means for managing excess baseload generation (i.e., preventing the risk of poisoning out a nuclear unit or shutting down and restarting (two-shifting) a fossil unit which could lead to reliability issues or the spilling of water).

(2) Facilitating an improved environmental state through the minimization of spill from hydroelectric resources.

(3) Providing a potential economic benefit to ratepayers in Ontario by reducing market prices during on-peak periods as a result of possible re-injection of SMO energy into Ontario. Segregated mode of operation allows OPG to sell energy to external companies who may have the ability to fill water reservoirs (typically off-peak) and resell the energy into Ontario during a subsequent on-peak period when it is economic for them to do so. Imports result in a decrease in hourly Ontario energy price ("HOEP") as these transactions generally occur when Ontario demand is high, supply is more constrained and more expensive generation is on line.

Within the IESO-administered market, exports are treated as a load. All export activity, including SMO, has the potential to increase HOEP as these activities increase market demand. As OPG's SMO activity typically occurs during off-peak periods, when market demand is lower and low cost supply is readily available, there may only be a small change in price to replace this energy with the next available generator in the dispatch stack. Therefore the impact on HOEP is expected to be minimal. Further, a recent study released by the IESO dealing with behavioural responses to market events indicates that export volumes tend to decrease following an increase in HOEP[2]. Therefore, based on this price/volume relationship, SMO exports would likely be counter-balanced by a reduction in other exports and leave HOEP at about the same level with or without SMO.

Ontario Regulation 53/05 does not address the treatment of incremental revenue from SMO transactions. However, OPG believes that the treatment of this incremental revenue should be consistent with the intent of the incentive mechanism under the Regulation. Specifically subsection 4 (2) of O. Reg. 53/05 includes a market-based incentive mechanism that encourages OPG to maximize its production at OPG's regulated hydroelectric generating facilities during peak periods or during times of highest market prices. Electricity output from the regulated hydroelectric generating facilities in excess of 1900 MW in any hour receives HOEP.

The regulated payment amounts have been calculated using an energy production forecast that includes all of R.H. Saunders' forecast energy production (whether injected into the Ontario market or into Québec). For purposes of the regulated payment amount calculation, SMO revenues are not used as an offset to the hydroelectric revenue requirement. The volume and revenue associated with SMO transactions are difficult to forecast as they are a response to hourly market-based signals (specifically demand and excess generation) and prices.

As described in the paragraphs that follow, OPG will share the net revenues it earned from SMO transactions for the interim period. In the descriptions below (and in the next section on Water Transactions), 1900 MWh in any hour refers to the threshold value for the hydroelectric incentive mechanism during the interim period.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is at or below 1900 MWh for any hour, OPG will receive $33/MWh for the

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[2] Presentation to the IESO Market Pricing Working Group, May 9, 2007, "Behavioural Response to Market Events".

production injected into the Ontario market and for any portion of the SMO volume below 1900 MWh. For this same SMO volume, the ratepayer receives either the net revenue between HOEP and $33/MWh if market prices are greater than the regulated rate or absorbs the difference if market prices are lower than the regulated rate. This treatment ensures that OPG receives the rate of $33/MWh for generation up to 1900 MWh which as described above was calculated by including all of R.H. Saunders' production. OPG will share with ratepayers on a 50/50 basis the net revenues[3] from the greater of the regulated rate or HOEP to the transaction sale price for the SMO volume at or below 1900 MWh. This treatment preserves an incentive to engage in SMO transactions while sharing with ratepayers revenues in excess of HOEP up to the transaction sale price.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is above 1900 MWh for any hour OPG will retain all SMO revenues. This treatment is consistent with the incentive mechanism set out at section 5 of O. Reg. 53/05 which provides that OPG is to receive market prices for this production.

Segregated mode of operation net revenues include incremental costs which consist of transmission export fees, transmission charges in other control areas and transmission losses between generator source and point of delivery. Segregated mode of operation transactions are also exposed to market price forecasting risk. These transactions are usually executed ahead of time and may be indexed to market price. If the actual price is greater than the forecast price used at the time of the decision to transact, margins associated with the transaction will be lower.

The net revenues from SMO transactions are acquired through OPG's non-regulated business which moves generation to higher priced markets. The non-regulated business incurs additional costs including; arranging, conducting and settling these transactions; IT systems; control and governance functions; and market memberships.

[3] SMO net revenues are defined as gross revenues less HOEP (or HOEP proxy costs), incremental variable costs, and costs associated with the non-regulated business. If the transaction is not indexed to HOEP but is executed at a fixed price, the HOEP for that hour is used as a proxy.

For the period April 1, 2005 to December 31, 2005, SMO net revenues were approximately $9.9M based on an average transaction premium[4] of approximately $14.26/MWh. For the calendar year 2006, SMO net revenues were approximately $5.4M based on an average transaction premium of approximately $10.14/MWh. Similarly for the calendar year 2007, SMO net revenues were approximately $4.4M based on an average transaction premium of approximately $9.28/MWh.

OPG also incurs additional costs and risks which have not been included in the figures above. By engaging in these transactions, OPG incurs a loss of production during switching operations and may experience other risks such as the IESO preventing or recalling the units as per the Market Rules; equipment failure (i.e., a breaker or switch failure) which may prevent the units from being connected back to Ontario until the equipment is repaired; or a unit being forced out. If the units are unable to segregate for the reasons identified above, OPG may be financially responsible for not delivering on its commitment to a transaction in another market.

OPG also requires a risk premium to recover exposure to risks such as counterparty credit and liquidated damages; and a reasonable rate of return in order to consider a commercial transaction.

For the test period, OPG is proposing a modified treatment, for incremental net revenues from SMO transactions, given the proposed change in the hydroelectric incentive mechanism (described in Ex. I1-T1-S1). The treatment of incremental revenues from SMO transactions needs to be integrated with this proposed hydroelectric incentive mechanism and take into consideration those changes suggested to the new mechanism. The main difference for SMO transactions is to the fixed threshold volume of 1900 MWh which will be replaced by an hourly volume that is equal to the actual hourly average net energy production[5] over a month (described in Ex. I1-T1-S1).

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[4] The average transaction premium is defined as the sale price less HOEP.

[5] Net energy production is defined as all production from the hydroelectric regulated assets including SMO production less load (including pump load from Sir Adam Beck Pump Generating Station).

Future SMO transaction volumes are anticipated to decrease as a new 1,250 MW direct current interconnection between Ontario and Québec comes into service. Phase 1 of the project has an in-service date of May 2009 and a capability of 900 MW. Phase 2 will be in-service in the spring of 2010 increasing the capability to 1,250 MW. This intertie will allow transactions directly and will therefore reduce SMO transactions.

## 5.0 WATER TRANSACTIONS

Water transactions between the New York Power Authority ("NYPA") and OPG are associated with the regulated hydroelectric facilities. NYPA and OPG are designated in their respective jurisdictions as the entities responsible for developing and operating the hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to agreements between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total water available for generation under the relevant international treaties. Water transactions are one means by which NYPA and OPG maximize energy production. Water transactions provide the opportunity to maximize use of the available water by permitting, under certain circumstances, an entity to extract at such entity's generating facility(ies) (the "Generating Entity") the potential energy from a portion of the other entity's share of the water available for power generation under the relevant international treaties. In return, the Generating Entity provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity. Historically, these water transactions were settled through physical transfers of energy between NYPA and OPG. However, since the opening of electricity markets in the respective jurisdictions, water transactions are now settled financially.

Water transactions generally occur for one of three reasons:

- Maintenance: Either NYPA or OPG can have outages that prohibit the full utilization of Canada's or the United States' share of water available for generation pursuant to the

- relevant Treaties.
- Economic Transactions: Transactions are conducted due to efficiency advantages associated with one entity's generation units over the other, or due to expected spill conditions.
- Ice: At times during the winter, the formation or flushing of ice at Niagara prevents either OPG or NYPA from utilizing Canada's or the United States' share of water available for generation pursuant to the relevant treaties. Under these circumstances the parties have agreed to share the losses associated with these water transactions.

Due to difficulties in forecasting both the water transaction volumes and their associated revenues, water transaction revenues are assumed to be zero and are not used as an offset to the regulated facilities' revenue requirement. However for the purposes of interim payments to the Ministry of Finance, gross revenue charges associated with these water transactions are forecast as described in Ex. F1-T4-S1.

For the interim period, OPG will share water transaction net revenues[6] consistent with the interim period treatment previously described for SMO and as further described below.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is at or below 1900 MWh for any hour, and OPG engages in a water transaction which allows NYPA to extract the potential energy from Canada's share of available water, OPG will receive $33/MWh for the production injected into the Ontario market and any portion of the water transaction volume at or below 1900 MWh. For this same water transaction volume that is at or below 1900 MWh, the ratepayer receives either the net revenue between HOEP and $33/MWh if market prices are greater than the regulated rate or absorbs the difference if market prices are lower than the regulated rate. This treatment ensures that OPG receives the rate of $33/MWh for production up to 1900 MWh in any hour including any allocation of water transaction energy. OPG and the ratepayer will share on a 50/50 basis the net revenues from the greater of the regulated rate or HOEP to

[6] Water Transaction net revenues are gross revenues less accommodation charges, and GRC.

the transaction sale price for the water transaction volume at or below 1900 MWh. This treatment preserves a market incentive to engage in water transactions while sharing with ratepayers revenues in excess of HOEP up to the transaction sale price.

For those hours when the output from OPG's regulated hydroelectric facilities is greater than 1900 MWh in any hour and additionally, OPG engages in a water transaction whereby it allows NYPA to extract the potential energy from Canada's share of available water, OPG will retain all water transaction revenues received from NYPA. This treatment is consistent with the incentive mechanism set out in section 4 (2) in O. Reg. 53/05.

When NYPA engages in a water transaction whereby it allows OPG to extract the potential energy from the United States' share of available water, OPG inherits a financial obligation equivalent to the energy production priced at HOEP. When the output from OPG's regulated hydroelectric facilities is less than 1900 MWh and there is a water transaction from NYPA to OPG, there is an energy credit to NYPA at HOEP. Any difference between HOEP and $33/MWh for the water transaction amount will be allocated as a cost in supplying this product. This treatment ensures that OPG receives the rate of $33/MWh for generation up to 1900 MWh. When the output from OPG's regulated hydroelectric facilities is greater than 1900 MWh, OPG will retain the entire obligation to pay NYPA at HOEP less accommodation charges associated with the transaction. Water transactions from NYPA to OPG have been relatively small with approximately $0.002M in gross revenues in 2005 and $0.2M in gross revenues in 2006. Once costs are included, the net revenues are not material enough to be addressed.

The majority of water transactions are for the purposes of salvaging the water that forms part of an entity's generation share that would otherwise be spilled over Niagara Falls due to the inability to use it or are used to facilitate ice procedures. Water transactions are required to ensure that the waters available for power generation under the relevant treaties are utilized in the most efficient manner, thereby maximizing all power potential from the resource.

For the period April 1, 2005 to December 31, 2005, water transaction incremental net revenue was $11.6M, for the 2006 calendar year was $12.5M and for the 2007 calendar year was $5.9M. Gross revenue charges costs associated with these transactions were $5.2M in 2005 (for the entire year), $4.1M in 2006 and $1.4M in 2007 (see Ex. F1-T4-S1). Water transaction net revenues were $7.8M during April 1 to December 31, 2005, $8.4M for 2006 and $4.5M for 2007.

For the test period, OPG is proposing a similar approach to the one used in the interim period, modified consistent with the treatment previously described for SMO.

It is expected that water transactions will decrease significantly when the Niagara tunnel is in-service since increased diversion capability will then be available to the Niagara stations.

## 6.0 CONGESTION MANAGEMENT SETTLEMENT CREDITS

All dispatchable generating facilities in Ontario are dispatched under the Market Rules by the IESO's dispatch scheduling optimizer ("DSO"). The DSO is an algorithm that is used by the IESO to determine prices and schedules for dispatch. Prices are first determined by an unconstrained run of the DSO, which does not take transmission or other constraints into consideration. This results in an unconstrained schedule. Dispatch, including OPG's prescribed generating facilities, is next determined by a constrained run of the DSO, which does consider constraints, and results in the schedule actually used to dispatch the generation. Any difference between the unconstrained schedule and the constrained or dispatch schedule can give rise to a CMSC payment, which is intended to compensate a market participant for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified).

The DSO will jointly optimize energy and the three types of operating reserve (ten minute spinning, ten minute non-spinning and thirty minute). Congestion management settlement credits payments are available for energy and for each of the three types of OR in each five minute interval of dispatch.

Congestion management settlement credits payments ensure that a market participant who has been constrained on or constrained off by system conditions beyond its control is made whole up to the operating profit they would have received under an unconstrained schedule. This is to ensure that no market participant is put at an advantage or disadvantage by virtue of their geographic position relative to the grid. The unconstrained schedule is used to set the market clearing price and constrained on units do not benefit from their higher offers. The amount of the CMSC payment is primarily based on operating profit which is calculated as the difference between the unconstrained and the constrained quantity as well as the difference between the offer price and the market clearing price.

The majority of the CMSC payments associated with OPG's prescribed assets are for energy, with OPG's regulated facilities attracting some CMSC OR.

Although transmission limitations are the major cause for differences between the unconstrained and constrained schedules, there are other factors that give rise to such differences. These include unit operating minimums, unit ramp rates and the use of actual metered output for the unit. The IESO does not provide the means for market participants to identify all of the reasons for a constrained on or constrained off event.

Congestion management settlement credits are subject to review by the Market Assessment and Compliance Department of the IESO. These reviews can result in recovery of CMSCs by the IESO if the CMSC was associated with a local transmission restriction and there was insufficient competition available to satisfy the restriction.

CMSC situations typically result in inefficient operation and/or the incurring of additional costs by generators, driven by market conditions. For example, constrained off situations can result in wasted or inefficient use of water as the generator is operated below its maximum efficiency point. Similarly, constrained on situations typically require inefficient use of the hydroelectric generating units above the point of maximum efficiency. In addition, in a constrained off situation, lost production will not be recoverable through the water variance account and if the CMSC value is less than the regulated rate, OPG will not recover its costs.

CMSC payments for regulated assets were $12.6M for 2005, $8.5M for 2006 and $7.7M for 2007. OPG will retain all CMSC payments from prescribed generating facilities as constrained operation typically gives rise to inefficient operation and increased costs. The CMSC payment is not incremental revenue but is an offset to lost production/revenue and increased costs that are generally not included in the revenue requirement. The CMSC payment during constrained events is reasonable compensation for such inefficiencies and costs. Moreover, CMSC OR is separately addressed by the variance account associated with the operating reserve ancillary service.

## 7.0 OTHER REVENUES – 2006 ACTUAL TO 2009 PLAN

Exhibit G1-T1-S1 Table 1 presents the revenues associated with the regulated hydroelectric assets.

Nuclear ancillary service revenues are presented in Exhibit G2.