DESIGN OF THE HYDROELECTRIC PAYMENT AMOUNTS

1.0 PURPOSE

This evidence provides a description of the proposed structure of the regulated hydroelectric payment amounts for the test period, which includes an incentive mechanism to encourage efficient use of the peaking capability of the regulated hydroelectric facilities.

2.0 HOW THE REGULATED ASSETS OPERATE WITHIN THE MARKET

OPG's regulated hydroelectric facilities and nuclear facilities operate as dispatchable generators in the IESO administered market. OPG is required to submit hourly offers to inform the IESO how much energy it has to sell and at what price. The IESO uses the offers and bids submitted by all dispatchable market participants (generators and loads), as well as transmission system information, to determine when and how much energy a dispatchable generator should provide. Dispatch instructions computed by the IESO's dispatch algorithm are issued for each five minute interval of the day, 24 hours per day, and 365 days per year. These instructions specify the generator's operating point for each five minute interval. The market clearing price[1], calculated by the IESO's dispatch algorithm, is used for two purposes. One, it is used to provide the market a price signal which indicates the marginal price of energy supply to meet the demand. Two, it is used for settlement purposes[2], with specific exceptions applied to OPG by O.Reg. 53/05.

Dispatchable generators are expected to respond to dispatch instructions that are issued every five minutes. Generators have different capabilities in following these instructions. Due to physical, regulatory or safety constraints, some generators are better suited to steady state operation with little or no deviation from a constant operating point. These generators are characterized as baseload. Other generators are well suited to quick and frequent

[1] Market clearing price is a market based price which is indicative of the marginal cost of energy supplied in order to meet demand. OPG's regulated assets do not receive market clearing price for energy delivered except for the production from the hydroelectric assets above 1900 MW.

[2] The regulated price for settlements is calculated after the fact. The IESO adjusts the market clearing price that OPG regulated generators receive, to the price set out in O. Reg. 53/05.

changes in output over a short period of time. These generators are characterized as peaking facilities. In terms of OPG's regulated assets, all of the nuclear and some of the hydroelectric stations are best suited for baseload (steady state) operation. While the majority of the peaking capability from OPG's regulated facilities is provided by the Sir Adam Beck Complex largely because of the integrated operation of the Sir Adam Beck Pump Generating Station ("PGS") within the complex, DeCew Falls and R.H. Saunders each have some minor peaking capability as well.

2.1 Hydroelectric Offer Strategy

The operating constraints for hydroelectric generators, such as water flow and elevation limits, are externally specified (see Ex. A1-T4-S2 for a discussion of the regulatory and legislative environment). A hydroelectric generator cannot follow a dispatch instruction that would cause it to violate a prescribed regulatory limit.

Hydroelectric generators that cannot readily respond to dispatch instructions every five minutes operate as baseload units and are offered into the market as price takers. [3] R.H. Saunders can be regarded as a baseload plant, as it has a very small peaking capability relative to its overall output. The facilities that comprise the Niagara Plant Group, collectively, have baseload as well as peaking capability, subject to prevailing water conditions.

As demand for electricity increases to its maximum, or peak value, generation supply is dispatched by the IESO to meet the demand. Progressively more expensive supply is dispatched as demand increases until the supply/demand equilibrium is achieved. There is a strong causal relationship between the supply/demand balance and the market clearing price. Generally, the lower the amount of available supply relative to demand, the higher the market clearing price.

[3] An offer price is the price at which a generator is offered into the market. The level of the offer price generally affects the outcome of the dispatch instruction from the IESO. Baseload generators are generally priced as 'price takers', meaning that their offer price is positioned well below the expected market clearing price. This is a recognized pricing strategy for ensuring steady state operation and avoiding marginal economic dispatch instructions.

OPG's regulated hydroelectric facilities currently receive a financial incentive to provide peaking supply in response to demand. Ontario Regulation 53/05 states that electricity production above 1900 MW will receive the market clearing price instead of the regulated rate (currently $33/MWh). For production from all regulated hydroelectric facilities at or below the 1900 MW production threshold, OPG receives the regulated rate. By utilizing market price signals, the regulated hydroelectric facilities can, when capable, produce more energy in high demand periods relative to lower demand periods. In such circumstances, both the market and OPG benefit. The market will benefit by having a peaking energy resource available during high demand periods offsetting otherwise more expensive generation resources or, in the extreme, preventing a scarcity situation in which the supply of the system was inadequate to meet demand. In turn, as is more fully described in section 3.0, ratepayers benefit through lower Ontario market prices. OPG financially benefits by shifting production to higher demand periods, thereby receiving the market clearing price, which is generally higher than the regulated payment amount.

3.0 VALUE OF REGULATED PEAKING ASSETS TO THE MARKET AND THE RATEPAYER

Given the importance of OPG's regulated hydroelectric facilities in meeting Ontario's electricity needs, it is crucial that these facilities be operated in a manner that maximizes their economic value to consumers. In particular, it is essential that the peaking capability of these facilities be utilized to meet peak system demands. The regulatory approach governing these facilities should provide the proper incentives to operate these facilities efficiently and in a manner that maximizes the value of their production.

Maximizing the value of the regulated assets involves time-shifting hydroelectric production into the hours of the day when demand and thus price are both generally at their highest. Operating the regulated hydroelectric facilities in this way ensures that the greatest amount of regulated hydroelectric production is available when it is most beneficial to customers and can displace typically more expensive peaking generation, which otherwise would be used. This activity is often referred to as "peak shaving".

Peak shaving can reduce market price in the highest priced hours, thereby resulting in savings for customers. The average annual value of this saving was estimated by OPG to range between $80M and $270M with a standard deviation estimated to range between $60M and $130M (see Chart 1 for a more detailed description of the analysis and benefits).

3.1 Why Pricing Sir Adam Beck Pump Generating Station Output Cannot be Considered Separately From the Pricing of the Other Beck Facilities

Sir Adam Beck PGS was designed and built for integrated operation with the other two Sir Adam Beck plants. Integrated operation of Sir Adam Beck PGS with the other Sir Adam Beck plants makes economic sense, optimizes peaking capability, allows OPG to efficiently provide automatic generation control and operating reserve at Sir Adam Beck II (see Ex. G1-T1-S1 for a discussion of these services), provides safety and system related benefits and is important in the control of the diversion of the Niagara River at the Sir Adam Beck complex. To sever Sir Adam Beck PGS operation from the rest of the Sir Adam Beck facility by developing its payment amounts separately from Sir Adam Beck I and Sir Adam Beck II would distort the incentives that currently exist and negatively impact the efficiency with which the Sir Adam Beck PGS performs the valuable roles required by the power system.

The supply of water (fuel) to the Niagara Plant Group plants is monitored by the Niagara River Control Centre. The Niagara River Control Centre is responsible for, among other things, ensuring compliance with the *Niagara Diversion Treaty of 1950*, regulating the water level of the Grass Island Pool[4] in accordance with the International Niagara Control Board Directive and regulating water flows in a manner that mitigates the effects of ice on the Niagara River.

The supply of water to both OPG and New York Power Authority (“NYPA”) plants is managed on an hourly basis by the Niagara River Control Centre, which identifies the water available for the entire Sir Adam Beck complex (including Sir Adam Beck PGS), and the NYPA plants. The operation of the Sir Adam Beck PGS has a direct impact on production from the

[4] The Chippawa-Grass Island Pool control structure is located in the Niagara River immediately upstream from the Falls and assists in apportioning flows between the Falls and power generation, to both the NYPA and OPG, in accordance with the 1950 Niagara River Diversion Treaty.

downstream facilities of Sir Adam Beck I and Sir Adam Beck II and vice versa. For example, an increase in Sir Adam Beck PGS output necessitates an increase in output at either Sir Adam Beck I or Sir Adam Beck II in order to maintain water elevation control at various locations including the Sir Adam Beck I and Sir Adam Beck II headponds and the cross-over (see Ex. A1-T4-S2 for a more detailed discussion). Similarly, a reduction in Sir Adam Beck PGS output would necessitate a reduction in Sir Adam Beck I or Sir Adam Beck II output simply because there would be less water flowing to these stations and there is limited storage capacity between these stations. Given the physical hydraulic constraints of the water delivery and storage structures, the operation of all plants and associated structures must be integrated to ensure control over water elevations and flow can be maintained within the regulatory limits. In order to maintain sufficient control to comply with these regulatory limits, Sir Adam Beck PGS operation cannot physically occur in isolation of Sir Adam Beck I and Sir Adam Beck II in a market that operates on five minute economic dispatch instructions.

4.0 EXISTING HYDROELECTRIC INCENTIVE MECHANISM

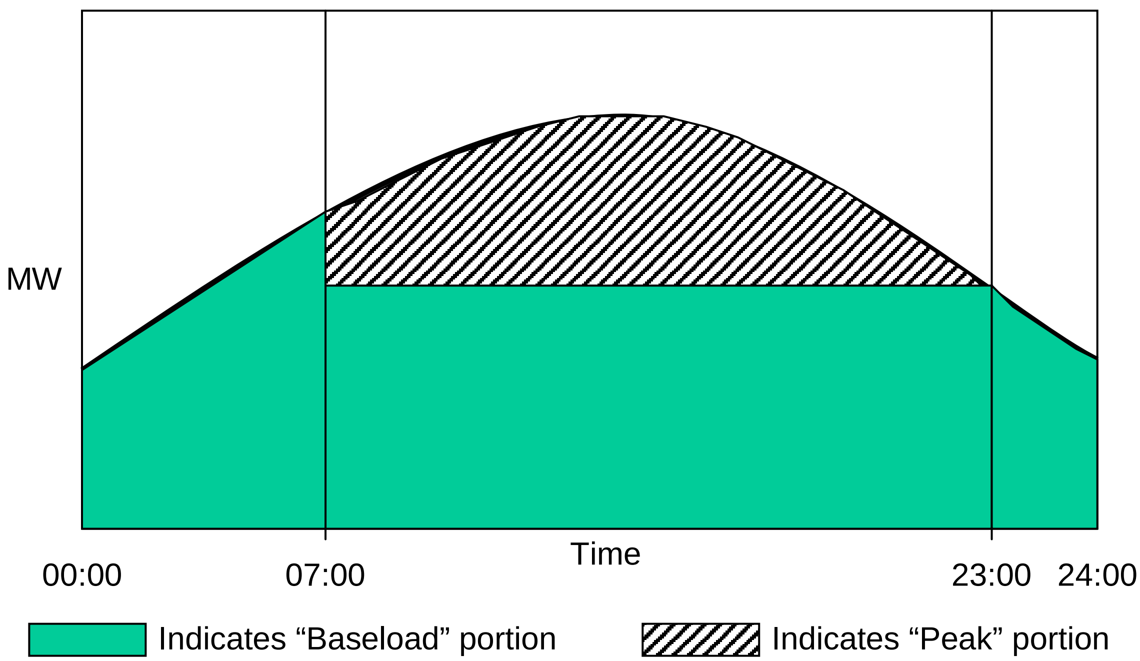
4.1 Background

Subsection 4 (2) of O. Reg. 53/05 establishes the payment amount for hydroelectric production from the prescribed facilities for the interim period. The structure of the payment amount includes an incentive to link the use of peaking capability from the regulated hydroelectric facilities with market prices. This incentive mechanism involves the use of an hourly baseload forecast quantity for the regulated hydroelectric facilities, which was established by the Province at 1900 MWh for any given hour. This quantity represents an estimate of the aggregate baseload output that the regulated hydroelectric facilities would typically provide to the market in each hour. Production up to this amount in any hour receives the regulated payment amounts. For quantities generated above this baseload threshold, output is deemed to be associated with the peaking capability of these facilities and as such receives market prices.

4.2 Baseload and Peaking Energy Calculation

For the interim period, the Province established the incentive mechanism quantity of 1900 MWh for any hour based on forecast production information provided by OPG. This energy forecast is comprised of a large baseload quantity and a much smaller peaking quantity. The baseload quantity was approximated as the forecast of all off-peak energy (i.e., all generation output from the regulated hydroelectric facilities between 11pm and 7am, seven days a week) plus the minimum output during on-peak hours over all days in the interim period.

Figure 1 - Baseload Minimum Output Calculation – Typical Day (figure is illustrative only)



As indicated in Ex. E1-T1-S1, forecast energy values are based on expected water flow conditions, and include all baseload and peaking energy from the regulated hydroelectric facilities.

Using the above definition for baseload energy, OPG determined hourly baseload forecast values for the interim period years (2005 - 2007)[5]. Instead of having three different annual values (i.e., one for each year of the interim period), O. Reg. 53/05 provides a single value that applies for the duration of the interim period. That value is 1900 MWh in any given hour.

4.3 How the Existing Hydroelectric Incentive Mechanism Works

Under the existing incentive mechanism, OPG is paid at market prices for all production from the regulated hydroelectric facilities in excess of 1900 MWh in any hour. This encourages OPG to maximize its hydroelectric production during the hours of the day with the highest market prices, which generally correspond to the highest demand periods.

4.4 Benefit of Experience and Rationale for Change

While the existing incentive mechanism encourages efficient and economic operations most of the time, OPG used its operational experience during the interim period to review and consider whether this methodology could be improved. OPG has identified circumstances where the existing incentive mechanism does not provide appropriate price signals. Consequently, OPG is proposing a new mechanism for the test period.

The existing mechanism, as specified in O. Reg. 53/05, provides the correct market price signal in most instances (i.e., it generally provides the appropriate signals to time-shift prescribed hydroelectric energy). However, there are specific situations where the mechanism does not provide the right price signal. Some of these circumstances are described below.

Some of the occurrences of sub-optimal signals involve decisions on whether to cycle the Sir Adam Beck PGS (i.e., to fill or release water from the Sir Adam Beck PGS reservoir). Because these decisions are complex and involve consideration of a number of variables, including the availability of water, the quantum of the regulated payment amount, the current hourly baseload forecast level, market prices, and on-peak versus off-peak pricing

[5] The hourly baseload forecast for the forecast energy production is estimated from historical values of energy production and “back-casted” hourly baseload forecast.

differentials, they require the use of market price signals to integrate as seamlessly as possible with the Ontario market. If a regulatory rate is used instead of a market price, the decisions that are made do not optimize the benefits that could be realized from these facilities.

For example, O. Reg. 53/05 provides a signal to OPG to base its pump decisions on $33/MWh (which is the opportunity cost to OPG of pumping instead of generating during periods when production is below 1900 MWh) instead of market prices. As a result, OPG may engage in pumping activities during times when the price differential between on-peak and off-peak prices would not justify it. Similarly, there are other occasions when OPG does not pump water based on the signals provided by O. Reg. 53/05, when market signals would justify such activity. The following numerical example is provided to further illustrate this point.

ILLUSTRATIVE EXAMPLE OF PUMP DECISIONS IN ACCORDANCE WITH O. REG. 53/05

For this particular day:

Average off-peak market price = $20 / MWh
Average on-peak market price = $40 / MWh
Sir Adam Beck PGS illustrative pumping costs[6] = $10 / MWh

- In order to recover the costs of pumping Sir Adam Beck PGS, the price differential between on-peak and off-peak hours needs to be at least $10 / MWh.

a) **<u>PROPOSED HYDROELECTRIC INCENTIVE MECHANISM -</u>** <u>Using Market Signals</u>

Price differential = $20 / MWh
($40 / MWh on-peak price - $20 / MWh off-peak price)

which is greater than $10 / MWh therefore Sir Adam Beck PGS would operate in **PUMP** mode overnight.

b) **<u>EXISTING HYDROELECTRIC INCENTIVE MECHANISM -</u>** <u>Using the Regulated Rate</u>

Price differential = $7 / MWh
($40 / MWh on-peak price - $33 / MWh Regulated Rate)

which is less than $10 / MWh therefore Sir Adam Beck PGS would **NOT PUMP** overnight.

In addition to responding to market price signals, Sir Adam Beck PGS may pump overnight for operational considerations such as automatic generation control at Sir Adam Beck II, diversion control at the Sir Adam Beck complex and maintaining a specific water elevation in the storage reservoir.

By employing the proposed incentive mechanism described below, the above inconsistency of not always responding to market signals can be corrected.

5.0 PROPOSED HYDROELECTRIC INCENTIVE MECHANISM

5.1 The Proposed Incentive Mechanism

[6] Costs associated with pumping Sir Adam Beck PGS are variable and include efficiency losses, load consumed during pump operations, gross revenue charge, replacement value of the water to refill the Sir Adam Beck PGS and IESO market charges (non-energy charges such as rural rate assistance, transmission charges, uplift, debt retirement charge, OPA administration charge and IESO energy market administration charge).

Under OPG's proposed incentive mechanism approach, OPG will be financially obligated to supply a given quantity ("hourly volume") in all hours and will receive the regulated rate for the hourly volume in all hours regardless of the actual output from its regulated hydroelectric facilities. If OPG produces more than the hourly volume in a given hour, it will receive regulated payment amounts up to the hourly volume, and market prices for the incremental amount of energy above this hourly volume. If OPG fails to produce the hourly volume in a given hour from its regulated hydroelectric facilities, the amount payable to OPG at the regulated rate will be reduced by the production shortfall multiplied by the market price. This notionally results in OPG "purchasing" the difference between the actual energy produced and the hourly volume from the market at market prices. Note that under this incentive mechanism, if there is no time-shifting of production from lower priced hours to higher priced hours (i.e., if production were to equal a constant volume for the entire period), OPG will only receive the regulated rate for the hourly volume.

OPG's proposed hydroelectric incentive mechanism improves its operational drivers by tying all decisions (both operational and financial), regardless of hourly output, to market signals instead of the regulated rate (see example in section 4.4). Using market signals is important to all market participants and to ratepayers as this will ensure that the operation of the regulated assets is optimized in all hours. Without an incentive mechanism tied to market signals, situations can occur where energy that could be transferred to peak hours is not transferred, or conversely, energy that could be transferred to peak hours is transferred contrary to what an efficient market would have dictated.

In addition to time-shifting operations, other operational and transaction decisions, such as those discussed in Exhibit G1, also need to be integrated with the proposed hydroelectric incentive mechanism. In OPG's submission, the best way to achieve this efficiency and ensure the lowest cost dispatch for the consumer, is to use a common market signal as the economic criteria for all decisions associated with these facilities.

By providing clear market signals, driven directly by the differential between on-peak and off-peak market prices, the proposed mechanism would also be responsive to the OEB's Filing

Guidelines[7] regarding an incentive price mechanism for the regulated hydroelectric facilities including Sir Adam Beck PGS.

5.2 Proposed Regulated Hydroelectric Payment Structure - Formula and Specific Values

The formula for the proposed hydroelectric payment amount is as follows:

$$\textbf{\textit{Monthly Hydroelectric Payment Amount}}^{8} =$$

$$\sum_{t} [MWavg \times RegRate + (MW(t) - MWavg) \times MCP(t)]$$

Where:

MWavg =	hourly volume or the actual average hourly net energy production over the month as explained in section 5.2.2.
RegRate =	the proposed regulated rate ($/MWh) for the regulated hydroelectric facilities as discussed in section 5.2.1.
MW(t) =	net energy production supplied into the IESO market for each hour of the month.
MCP(t) =	market clearing price for each hour of the month.

5.2.1 <u>Proposed Incentive Mechanism Price Equals the Hydroelectric Regulated Rate</u>

As indicated in Ex. K1-T2-S1, the proposed regulated rate for the regulated hydroelectric facilities is $37.90/MWh. This regulated rate is calculated based upon the test period revenue requirements for the regulated hydroelectric facilities divided by the forecast net energy output from the regulated hydroelectric facilities over the test period. This will be the regulated payment amount for the hourly volume.

[7] EB-2006-0064 OEB Filing Guidelines for OPG, Setting Payment Amounts for Prescribed Generation Assets, July 27, 2007.

[8] For simplicity the formula is expressed using hourly values. Upon implementation the formula will be adapted to use values to correspond with each five minute interval in the market. Implementation will be consistent with existing settlement practices.

5.2.2 Proposed Incentive Mechanism Hourly Volume

OPG proposes an hourly volume for the incentive mechanism that changes each month and that is equal to the actual average hourly net energy production over the month. The hourly volume would be calculated as the sum of the net energy production (i.e., energy production net of load including Sir Adam Beck PGS pump load) from the prescribed assets for that month (in MWh) divided by the number of hours in the month. At the end of each month, the actual net energy production supplied into the IESO market only (i.e., segregated mode of operation[9] production is not included) for each hour of the month would be reconciled against the hourly volume for that month. It should be noted that the hourly volume would fluctuate based on monthly production, but in 2008 it is forecast to average out to 1986 MWh in each hour of the month[10] assuming that OPG achieves its 2008 production forecast of 17.4 TWh. Similarly for 2009 the hourly volume is forecast to average out to 2114 MWh in each hour assuming that OPG achieves its 2009 production forecast of 18.5 TWh (see Ex. E1-T1-S1). Use of an hourly volume based on actual production allows for a higher volume of energy at the regulated payment amount than a predetermined volume because the volume can be established without the need to incorporate a risk premium to adjust for forecast uncertainty.

As per Ex. E1-T1-S1, the production forecast for OPG's regulated hydroelectric facilities is based on water models that do not take into consideration hour to hour fluctuations in water conditions. In addition, there is the potential for large fluctuations in the annual flow levels that are beyond OPG's control and which are difficult to predict. Although a hydroelectric variance account has been proposed to address changes in forecast production due to water conditions, it has not been designed to mitigate the inherent risk associated with using a predetermined production level in the incentive mechanism. If a predetermined annual production level is used, this risk is greater during the Niagara tourist season[11] when flows to the Sir Adam Beck Generating Stations are reduced to sustain the Niagara Falls flow as per the Niagara Diversion Treaty (see Ex. A1-T4-S2). It is also during this period that market

[9] Segregated mode of operation is described in Exhibit G1.
[10] Average net energy production per month forecast for 2008 = 17,440,865 MWh/ 8784 hours per year. 2008 is a leap year with 8784 hours.
[11] Niagara tourist season is April 1st to October 31st of each year. Tourist hours are 0800-2200 April 1st to September 15th and 0800-2000 September 16th to October 31st.

demand increases, which generally results in higher peak market prices. For this reason, it is difficult to set a predetermined production volume in advance for the proposed incentive mechanism that balances OPG's risks and customer benefits. In order to alleviate this difficulty, OPG proposes to base the volume on actual monthly production, rather than on a predetermined forecast production level.

5.3 Incremental Risk Associated with Proposed Incentive Mechanism

The proposed incentive mechanism increases risk for OPG relative to the existing mechanism in two specific areas; production risk and market price risk.

In addition to providing market price signals for all of OPG's operational decisions, the proposed incentive mechanism would result in OPG assuming the additional downside financial risk associated with under production (within the context of the variance accounts, as discussed in Exhibit J).

In hours where OPG's production is less than the hourly volume, OPG would be financially obligated to "notionally purchase" the shortfall from the market, at market prices. If prices are high, OPG could incur significant reduced revenues in these hours. Similarly, if OPG time-shifts water to produce above the hourly volume and prices do not materialize as forecast, OPG could incur costs associated with incremental pumping of the Sir Adam Beck PGS that would not be recovered through the market price in that hour. These costs include efficiency losses associated with non-optimal operation of units, load associated with incremental pumping and IESO market or non-energy related charges. As the energy and efficiency losses are not due to water conditions they would not be covered by the variance account and would therefore increase OPG's risk in recovering its revenue requirement.

The primary difference between the existing incentive mechanism and the proposed incentive mechanism is that under the proposed mechanism OPG faces more financial risk in the form of having to "notionally purchase" any shortfall in production whereas no action is required with the existing mechanism. In essence, the existing mechanism protects OPG from the downside risk associated with under-production, whereas the proposed incentive mechanism leaves OPG fully exposed, and hence gives a much greater incentive to time-shift.

Even with an hourly volume that changes each month, OPG would still be exposed to water variability risks as the flow may change during the month affecting the monthly average and exposing OPG to price risk. As an example, the Niagara Falls flow requirement decreases on September 16 of each year and energy production will be higher after this date due to the increased flow to the plants. This change results in a greater average volume for the month of September. For the first part of the month, OPG will be exposed to under production risks and may be required to notionally purchase energy from the market during a period when market prices could be high.

Further to the above, OPG also incurs risks associated with operating in the market and relying on market prices such as managing excess baseload generation and spill, as well as timing the offering of generation into the highest demand hours.

5.4 Benefits of Proposed Incentive Mechanism

Section 3.0 discussed the potential savings for consumers that could be achieved by time-shifting water and operating four Sir Adam Beck PGS units during the peak hours of the day to displace typically more expensive generation. This time-shifting profile is forecast to reduce the hourly Ontario energy price (“HOEP”) by between $0.4/MWh and $1.20/MWh with an annual estimated savings ranging between $80M and $270M (see Chart 1).

It will not always be economical for Sir Adam Beck PGS to pump and generate at full capacity. Market prices will determine how many Sir Adam Beck PGS units should generate during the day and running four units may not be cost efficient. The impact on HOEP of operating a different number of Sir Adam Beck PGS units and the estimated value in savings to market consumers is outlined in Chart 1.

Chart 1

Estimated Benefits of Sir Adam Beck Complex Operations to Consumers

Estimated Benefits of Sir Adam Beck Complex Operations to Consumers[12]				
Number of Sir Adam Beck PGS Units Generating During the Peak Hours of the Day	**Estimated Daily Reduction in HOEP**		**Estimated Average Annual Savings to Consumers**	
	Average ($/MWh)	Standard Deviation ($/MWh)	Average ($M)	Standard Deviation ($M)
1	0.4	0.3	80	60
2	0.7	0.4	150	80
3	1.0	0.5	220	110
4	1.2	0.7	270	130

As previously indicated, because of the enhancement to the market price signal to time-shift water, the proposed incentive mechanism represents an improvement over the existing mechanism for the interim period as it facilitates the increased usage of the Sir Adam Beck PGS and more optimal use of the Sir Adam Beck complex provided that it is economic to do so.

OPG has forecast its incremental revenues associated with the proposed incentive mechanism. Incremental revenues are the result of time-shifting water into hours of the day with naturally higher prices (due to higher demand), and increasing production for these hours beyond the proposed incentive mechanism volume, thereby earning market prices on the difference between actual output and the proposed incentive mechanism volume. There is considerable uncertainty in forecasting the incentive revenues and the costs because they are dependent on several factors including market prices.

The expected annual value of gross incentive revenues is estimated to be approximately $12M above and beyond the proposed revenue requirement. The distribution of results from

[12] These values were derived using multiple market simulations based on forecast market prices for 2008 and profiles that include six Sir Adam Beck PGS units pumping at night and the specified number of Sir Adam Beck PGS units dispatched and providing energy during the day. The analysis further assumes that Sir Adam Beck PGS generates the specified number of units continuously for the peak hours of the day, 365 days of the year.

OPG's modeling of this mechanism includes at a five percent confidence level an incremental incentive of $5M (low estimate) and a ninety-five percent confidence level an incremental incentive of $19M (high estimate). These values were derived using forecast market prices for 2009 with an expected average of approximately $44/MWh, a five percent confidence level of $34/MWh (low estimate) and a ninety-five percent confidence level of $57/MWh (high estimate). The expected value of $12M was arrived at using multiple market simulations based on the statistical forecasts of production and market prices. Changes in the market price forecast will directly impact the incentive revenues and the costs associated with time-shifting production.

The costs associated with these time-shifting activities include pump energy consumption, pump non-energy charges, efficiency losses and GRC adjustments. OPG proposes that the actual costs incremental to those included in the regulated hydroelectric revenue requirement will be recovered through revenues associated with the proposed hydroelectric incentive mechanism.

OPG also incurs additional risks associated with operating in the market and relying on market prices which will further reduce the value of this incentive (section 5.3 describes these risks).

Further to the above, if the spread between an on-peak and off-peak market price is large enough, there may be an economic opportunity to increase the utilization of the Sir Adam Beck PGS by pumping more water; and/or to "super-peak" the Sir Adam Beck II units by operating at maximum gate.[13] Operating in this manner gives rise to greater costs, which will need to be recovered, but provides savings for market consumers by further reducing the average market price. As the maximum attainable potential of "super-peaking" the regulated assets is highly dependent on real-time market prices and operational conditions during the specific day, the estimated benefit of "super-peaking" could not be forecast with any accuracy.

[13] Operating a unit at maximum gate means that the units will operate at a lower efficiency point thereby consuming more water per kWh of electricity production but will generate higher energy production for that particular hour. This is often referred to as "super-peaking" operation.

In summary, providing the correct market drivers to peak the regulated hydroelectric facilities provides the following benefits:

- The market consumer benefits from lower market prices with an estimated annual value ranging between $80M and $270M.
- The market benefits by having a peaking energy supply to meet high demand periods.
- OPG benefits with a modest gross incentive payment forecasted to be approximately $12M for 2009.

DESIGN OF THE NUCLEAR PAYMENT AMOUNTS

1.0 PURPOSE

The purpose of this evidence is to describe the proposed design of the nuclear payment amounts and to explain why it is the best approach for maximizing efficient use of the nuclear facilities.

2.0 PROPOSED DESIGN OF NUCLEAR PAYMENT AMOUNTS

The OEB Methodology Report solicits input on the question of maximizing the efficient use of the nuclear assets. Given the importance of the nuclear facilities in meeting Ontario's electricity needs, it is important that the regulatory regime governing these facilities support their economically efficient operation.

OPG proposes a payment design that includes both a fixed monthly payment of $58.2M/month and a variable payment of $41.5/MWh. The fixed payment would allow for recovery of 25 percent of the revenue requirement for the nuclear facilities and the variable payment would allow for recovery of the remaining 75 percent of the revenue requirement. The significant variable component of the proposed payment amount design provides a strong incentive for OPG to maximize its nuclear unit availability, while the smaller fixed component, which would be independent of the level of energy production in that month, allows for partial recovery of the fixed costs. The details of the calculation for the payment amounts are provided in Ex. K1-T3-S1. The rationale for including a fixed component of 25 percent in the payment amount design is provided in Section 3 of this evidence.

3.0 FIXED COMPONENT OF NUCLEAR PAYMENT AMOUNT

The costs of OPG's nuclear facilities are over 90 percent fixed. Accordingly, OPG is seeking recovery of some of its fixed costs through a partially fixed payment structure. Because costs are fixed to such a high degree, OPG bears a significant amount of risk when the entire revenue requirement is recovered through a variable, energy-based payment. For example, during an unforeseen nuclear unit outage, costs continue to accumulate (and, in fact, may do so at an accelerated rate due to additional, unforeseen costs associated with the forced outage itself) but revenues for the unit drop to zero. OPG's current interim payment amount design is 100 percent variable and paid on a per MWh basis.

The rationale for including a fixed component in the design of the payment amounts is based on the following three considerations:

- Over 90 percent of the costs associated with OPG's nuclear facilities are fixed and the design of the payment amounts should reflect, at least to some extent, the underlying cost structure.
- Generators in Ontario and other jurisdictions recover fixed costs.
- Rate structures approved by the OEB for other regulated entities typically include both a fixed and variable component and the percentage of the revenue requirement recovered through the fixed component is often greater than the 25 percent proposed for the nuclear payment amount.

Taking the above into consideration, 25 percent is seen as an appropriate percentage for the fixed component of the nuclear payment. Each of these considerations is addressed below in sections 3.1 - 3.3.

3.1 OPG's Nuclear Cost Structure

OPG's nuclear facilities are characterized by relatively high fixed costs and low variable costs. OPG's analysis considered the variability of costs and revenues with production assuming continued availability of the facilities. Fixed costs are defined as those that do not fluctuate as long as the facilities are available to produce electricity within their historical average range of output. Variable costs are those that fluctuate with the level of electricity output.

<u>Variable Costs</u>

The only costs that vary with production are:

- Nuclear Fuel (including the variable portion of used fuel disposal costs)
    - o Nuclear fuel and the corresponding variable portion of used fuel management/disposal costs are directly related to station production levels.

  - However, the portion of nuclear fuel costs held as inventory carrying costs are fixed.

Fixed Costs

The following costs are fixed:

- Depreciation
  - Depreciation is a cost primarily associated with the fixed asset value of OPG's regulated facilities and as such it does not vary with production but is primarily affected by the additions to and retirements of assets in service.

- Interest
  - Interest is a cost associated predominantly with the financing of OPG's capital investment in its regulated facilities (interest costs are presented in Ex. C1-T1-S1). As such, the cost does not vary with production.

- Property Tax
  - OPG is responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the Province of Ontario. These payments are directly associated with OPG's property and the generation assets (property taxes are presented in Ex. F3-T2-S1). As such, these costs do not vary with production.

- Capital Taxes
  - By definition, capital tax varies with the level of OPG's capital only (capital taxes are presented in Ex. F3-T2-S1). Therefore, capital tax expense is fixed and does not vary with the level of production.

- Asset Service Fee
  - The asset service fee represents charges to the nuclear facilities for the use of certain assets held centrally, such as OPG head office at 700 University Avenue and OPG-wide IT assets (the asset service fee is described in detail at Ex. F3-T3-S1). Because the use of these assets by the generation segments does not vary

- materially with production, these costs are fixed.

The following cost is predominantly fixed:

- Operations, Maintenance and Administration (OM&A)
  - OM&A costs are largely fixed for OPG's nuclear facilities over the planning period. These costs consist primarily of maintenance costs, project costs, costs of operating staff, business level and corporate level overhead costs, including allocations of corporate function costs and centrally-held costs. The vast majority of these costs do not vary with production, although certain costs which are incremental to the ongoing OM&A costs such as outage costs may vary depending on the outage requirements and schedules for the various plants/units. Also, OM&A project costs will vary depending on the specific projects or tasks that are included in the project.

  - Maintenance needs to be performed in order to ensure that the units are available to generate safely when required. Most maintenance programs are not driven by the level of production (because, other than planned outages for maintenance, nuclear units are assumed to run all the time), but rather by the passage of time and regulatory requirements to perform regular maintenance. The key drivers of Nuclear base OM&A costs are presented in Ex. F2-T2-S1.

Other Costs

The following costs are neither fixed nor variable and are therefore not included in the analysis presented:

- Income Taxes
  - To the extent the nuclear payment is fixed then income taxes are largely fixed; to the extent the nuclear payment is variable then the income taxes would be largely variable. Accordingly, because the characterization of these costs is determined by the structure of the payment, this expense has not been used in the cost analysis.

- Return on Equity
  - The return on equity is also directly dependent on the payment design and therefore the return on equity cost has not been included in this analysis.

  - The percentages of fixed and variable costs for the nuclear revenue requirement forecast for the years 2008 and 2009 are presented in Chart 1 below. The very high percentage of fixed costs supports the need for a design of the nuclear payment amount that provides some assurance of fixed cost recovery. To the extent the payment amounts do not directly reflect the nature of the nuclear facility costs, OPG's earnings are subject to greater variability and therefore risk. Both the Market Surveillance Panel and the IESO have recognized that Ontario market prices are often insufficient to allow generators to earn sufficient revenues[1, 2], resulting in marginal generators not covering all costs and discouraging additional investment, thereby necessitating other means of ensuring long-term adequacy, such as contracting.

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[1] MSP Report dated December 13, 2006 (page vii).

[2] IESO CBA on Operating Reserve states "The OPA as central planner is charged with identifying future investment needs in the province and contracting for this investment. In general, they are tasked with providing the incentives (through contract) to invest when the market itself does not provide these incentives." page 13.

Chart 1

Fixed / Variable Components of Nuclear Costs ($M)

	2008 Plan	2009 Plan
Variable Components		
Nuclear Fuel	162	204
Total Variable	**162**	**204**
Fixed Components		
OM&A	2185	2169
Depreciation & Amortization	350	389
Deemed Interest[1]	86	88
Property Tax	14	14
Capital Tax	8	8
Total Fixed	**2643**	**2668**
Total Variable and Fixed	2805	2872
% Variable	***6%***	***7%***
% Fixed	***94%***	***93%***

[1]Based on a deemed capital structure of 57.5 percent equity and 42.5 percent debt, an ROE rate of 10.5 percent and a deemed interest rate of 5.76 percent for 2008, and 5.92 percent for 2009.

3.2 Generator Cost Recovery

Many North American electricity generators receive fixed payments, in some form, to assure recovery of fixed costs. The traditional regulatory approach applied to cost allocation and rate design for electric utilities includes a capacity charge for generation function costs.

Traditionally, a utility first functionalizes its costs as generation, transmission, distribution or administrative, and general costs. Generation function costs are typically classified as capacity- or energy-related costs to reflect cost causation.

Capacity-related costs are largely fixed, are incurred to meet peak demand, and are related to the size of the plant. They typically do not vary with production volumes and include fixed costs such as depreciation, return and related taxes, and fixed operations and maintenance expenses. Energy-related costs are incurred to produce energy and typically vary with production volumes. They include fuel and variable operations and maintenance expenses.

The recovery of fixed costs through an energy-based charge as reflected in OPG's current payment design structure raises the following concerns:

- The design of the payment amounts does not reflect cost causation.
- It creates increased volatility in the utility's revenue and income, and causes mismatches between the utility's costs and revenue, because costs that are fixed are recovered based on energy usage that is variable. Increased volatility in revenue and income can give rise to increased financing costs for OPG.

OPG's nuclear facilities provide both capacity and energy to the IESO grid and therefore a payment amount design that includes a fixed component to recognize the provision of capacity and a variable component to recognize the provision of energy is appropriate. Competitive electric markets neighbouring Ontario, specifically, New York, PJM, and New England, have recognized the need to provide for fixed cost recovery for electricity generators and have established capacity markets.

Although Ontario's IESO market has not established a capacity market, the hybrid market structure in Ontario provides contracting mechanisms to provide fixed cost recovery for generation. Contracted generation in Ontario has a high degree of assurance of recovery of fixed costs through the structure of OPA contracts. For example, the contract structure for Ontario's clean energy supply contracts includes a monthly contingent support payment which is the monthly net revenue requirement less the imputed net revenue, where the imputed net revenue represents the expected net revenue from energy sales given the characteristics of the facility.

It is appropriate for the design of the nuclear payment amounts to reflect the common approach of allowing for recovery of at least a portion of fixed generation costs through a payment that is not based on energy production.

3.3 Approved Rate Structures for Other Regulated Utilities

OPG analyzed the rate structure of both Union Gas and Enbridge Gas, as these two large utilities have a long history of rate regulation by the OEB and their costs have been subject to very detailed cost allocation reviews. The analysis of the rates/charges recently approved for Union Gas, as reflected in schedules 6 and 20 of its EB-2005-0520 Working Paper, indicate that Union Gas recovers approximately 50 percent of its approved non-commodity revenue requirement through charges that do not vary with throughput. In the case of Enbridge, their evidence currently before the OEB indicates that approximately 20 percent of its non-commodity revenue requirement is recovered through charges that do not vary with throughput.

Hydro One collects about 50 percent of its revenues from distribution customers through fixed charges.

While Union and Enbridge are integrated utilities and do not demonstrate the unique characteristics of OPG’s prescribed facilities, OPG used the above rate structures to establish a reasonable level for the fixed component of the payment design for the nuclear facilities.

3.4 Conclusion

OPG recognized that the level of its fixed costs, greater than 90 percent of total revenue requirement, was too high for recovery through a fixed charge because a significant variable component of the payment amount incents OPG to maximize production from the nuclear facilities.

OPG's proposed payment design that includes a fixed monthly payment, allowing for partial recovery of fixed costs along with a variable payment that acts as a strong incentive to maximize unit availability, is considered by OPG to be the best approach for maximizing efficient use of the nuclear facilities.

OPG suggests that the proposed recovery of 25 percent of the revenue requirement for the nuclear facilities through the fixed monthly payment can be adjusted in the future based on an assessment of both its effectiveness in maximizing efficient use of the nuclear facilities and actual fixed costs incurred for the nuclear facilities.