Undertaking 168

Page 121, line 23 to Page 122, line 21

Re: PUB-NLH-388 (Table 1)

Undertake to provide the relevant orders relating to deferral accounts established for Manitoba Hydro, Ontario Power, Nova Scotia.

Please see Undertaking 168, Attachments 1, 2 and 3.

MANITOBA	**Board Order 99/01**
THE PUBLIC UTILITIES BOARD ACT	**June 15, 2001**

Before: G. D. Forrest, Chair
M. Girouard, Member
M. Santos, Member

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER JUNE 1, 2001

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Executive Summary

Natural gas is a commodity subject to market fluctuations as a result of supply and demand forces in an unregulated market. The dramatic increase in natural gas prices in Manitoba over the last year, as a result of market conditions, is consistent with the dramatic increases in natural gas prices being experienced throughout North America, caused in part by an upturn in North American demand.

Centra recovers the price paid for natural gas from their customers with no mark-up, and realizes no profit from gas cost increases. This Order addresses changes in the commodity cost of Primary Gas, which represents only a portion of the customer's total monthly bill. Other components of the bill include costs related to supplemental gas, transportation to Centra, distribution to the customers, alternate gas service, if applicable, and a basic monthly charge.

Centra utilizes a Primary Gas Purchased Gas Variance Account ("PGVA") to track the difference between the gas cost recovered from customers and the actual gas costs paid by Centra for Primary Gas. The balance in this account is discharged by way of a Primary Gas rate rider that is added to the Primary Gas base rate. The total of the two amounts is the Primary Gas sales rate that appears on a customer's bill.

Because of recent increases in the cost of gas, the PGVA balance owing to Centra by customers at February 28, 2001 was in excess of $100 million. In this Order, the Board has approved Centra's request to create a Primary Gas Deferred Gas Recovery Account, but directed Centra to use the term Primary Gas Deferral Account. The account will be comprised of the Primary Gas PGVA balance at April 30, 2001, net of any collections from the existing rate rider to May 31, 2001.

The Primary Gas Deferral Account will be collected through a Primary Gas Deferral Rate Rider over a 24-month period. Based on a principle that all customers who created the balance should pay their fair share, the Primary Gas Deferral Account Rate Rider will be collected from all System and Buy/Sell customers of record at April 30, 2001. This rate rider will be shown as a separate line on the customer's bill. In the interest of equity and fairness, any gas customers who signed an agreement with an Aggregator, Broker or Marketer ("ABM") prior to April 30, 2001 but had not been converted, will be subject to this rate rider.

The Board directed Centra to modify the existing Rate Setting Methodology to incorporate 100% of the change between the 12-month forward price for Western Canadian supplies, weighted for the cost of gas in storage, and the existing Primary Gas sales rate. With the move to a 100% inclusion rate, changes in the commodity price of natural gas will be passed through to Centra's rates on a more timely basis, and Primary Gas sales rates will be more reflective of current market rates. Centra's customers can achieve some degree of bill stability through the use of Centra's existing Budget Billing Plan.

The Board has denied Centra's request for any change in Primary Gas sales rates to be effective June 1, 2001. Any changes in Primary Gas sales rates as a result of this Order will be included in Centra's application for sales rates to be effective for all gas consumed on and after August 1, 2001.

Sommaire

Le gaz naturel est un produit sensible aux fluctuations du marché qu'entraînent les forces de l'offre et de la demande dans un marché non réglementé. Au Manitoba, la hausse phénoménale des prix du gaz naturel au cours de la dernière année, découlant des conditions du marché, va de pair avec les hausses tout aussi importantes des prix du gaz naturel enregistrées en Amérique du Nord et causées, en partie du moins, par l'augmentation de la demande en Amérique du Nord.

Centra récupère le prix payé par leurs clients pour le gaz naturel sans majoration et ne réalise aucun bénéfice provenant des hausses du coût du gaz. Ce décret vise les changements apportés au coût des services publics de gaz primaire, qui ne représentent qu'une partie de la facture mensuelle totale pour le client. D'autres éléments s'ajoutant à cette facture comprennent les coûts du gaz d'appoint, les frais de transport chez Centra, les frais de distribution chez les clients, le service du gaz de remplacement, le cas échéant, et un tarif mensuel de base.

Centra utilise un compte d'écarts Gaz primaire acheté (« PGVA ») afin de comptabiliser l'écart entre le coût du gaz récupéré des clients et les coûts réels du gaz payés par Centra pour le gaz primaire. La différence de cette comptabilisation est acquittée par un supplément de tarif qui est ajouté au tarif de base du gaz primaire. La somme des deux montants représente le prix de vente du gaz primaire apparaissant sur la facture d'un client.

En raison des récentes hausses des coûts du gaz, le solde du compte PGVA dû par les clients à Centra, en date du 28 février 2001, excédait 100 millions de dollars. Par ce décret, la Régie a approuvé la demande de Centra visant à créer un Compte de reprise différée Gaz primaire, en lui indiquant toutefois d'utiliser le terme Compte de gaz primaire reporté. Le compte comportera le solde PGVA du gaz primaire au 30 avril 2001, exempt de tout recouvrement provenant d'un supplément de tarif existant jusqu'au 31 mai 2001.

Le recouvrement du Compte de gaz primaire reporté sera effectué par le biais d'un supplément de tarif échelonné sur une période de 24 mois. En partant du principe que tous les clients qui ont participé à la création de ce solde devraient payer leur juste part, le recouvrement du supplément de tarif du Compte de gaz primaire reporté sera effectué auprès de tous les clients Systèmes et Achat/Vente au dossier en date du 30 avril 2001. Ce supplément de tarif sera indiqué sur une ligne distincte sur la facture du client. Dans un souci d'équité et de justice, ce supplément de tarif visera tous les clients qui auront conclu une entente non convertie avec un revendeur, un courtier ou un distributeur avant le 30 avril 2001.

La Régie a exigé que Centra modifie la méthodologie actuelle d'établissement des tarifs afin d'y inclure 100 % des fluctuations entre le prix à terme de 12 mois pour les approvisionnements de l'Ouest canadien, pondéré par le coût du gaz entreposé, et les tarifs actuels du gaz primaire. Avec un taux d'inclusion de 100%, les fluctuations du prix à la consommation du gaz naturel se répercuteront sur les tarifs de Centra sur une base plus opportune, et les tarifs du gaz primaire à la consommation reflèteront plus précisément les tarifs actuels du marché. La clientèle de Centra pourra bénéficier d'une certaine stabilité de sa facturation par l'utilisation du régime de versements égaux existant de Centra.

La Régie a rejeté la demande de Centra concernant toute modification du prix à la consommation du gaz primaire entrant en vigueur le 1er juin 2001. Toute modification apportée au prix à la consommation du gaz primaire en raison de ce décret sera incluse dans la demande de Centra pour les prix à la consommation en vigueur pour tout le gaz consommé le et après le 1er 2001.

1.0 Appearances

R. Peters S. Berthaudin	Counsel for The Manitoba Public Utilities Board ("the Board")
M. Murphy B. Zarnicki	Counsel for Centra Gas Manitoba Inc. ("Centra")
B. Meronek, Q.C. K. Saxberg	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. ("CAC/MSOS")
D. Brown	Municipal Gas, a division of Direct Energy Marketing Limited ("Municipal Gas")

2.0 Witnesses for Centra

G. Neufeld	Consultant, Former Manager, Gas Forecasts Department, Centra
G. Meyer	Manager, Rates Department, Centra
M. Kast	Manager, Gas Supply Services, Centra
V. Warden	Chief Financial Officer, Vice President, Finance & Administration, Manitoba Hydro
R. Feingold	Consultant, Navigant Consultants Inc.

3.0 Intervenors of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. ("CAC/MSOS")

Municipal Gas, a division of Direct Energy Marketing Limited

Communications, Energy and Paperworkers Union, Local 681 ("CEPU")

G. Finkle

4.0 Witnesses for CAC/MSOS

G. Forget	Consultant
J. Todd	President, Econalysis Consulting Services Inc.

5.0 Witnesses for Municipal Gas

C. MacMillan	Senior Vice President Market Operations, Direct Energy Marketing Limited
B. Soutiere	Senior Vice President Canadian Marketing, Direct Energy Marketing Limited
K. Melnychuk	Manager, Manitoba Region, Municipal Gas, a division of Direct Energy Marketing Limited

6.0 Presenters

A. Cerilli	President, The Manitoba Federation of Union Retirees
T. Ducharme	People in Equal Participation Inc.
S. Horyski	Citizen
T. Nicholson	Project Coordinator, West Centra Gas Committee
K. Silvera	Citizen

7.0 Background

Natural gas is a commodity subject to market fluctuations as a result of supply and demand forces in an unregulated market. The dramatic increase in natural gas prices over the last year results from current market conditions, and is a North American phenomenon, in part caused by an upturn in North American demand.

Centra recovers the price paid for natural gas from their customers with no mark-up, and realizes no profit from gas cost increases. The commodity cost of Primary Gas represents only a portion of the customer's monthly bill. Other components of the bill include costs related to supplemental gas, transportation to Centra, distribution to the customer, alternate gas service, if applicable, and a basic monthly charge.

In Order 55/00 dated April 17, 2000, The Public Utilities Board (the "Board") implemented a mechanism to respond to frequent changes in the cost of Primary Gas by approving a Rate Setting Methodology ("RSM") whereby the sales rate of Centra Gas Manitoba Inc. ("Centra") for Primary Gas would be adjusted at the beginning of each gas quarter to reflect:

1. 50% of the difference between the updated 12-month forward price for Western Canadian supplies of natural gas, weighted for the cost of gas in storage, and the Primary Gas Sales Rate set in the previous quarter; and

2. A rate rider to dispose of the estimated accumulated Primary Gas Purchased Gas Variance Account ("PGVA") over the next 12 months of forecast volume.

The Rate Setting Process approved by the Board requires Centra to file its application during the first week of the month prior to the commencement of each gas quarter

(February 1, May 1, August 1, and November 1) and to provide public notice during the second week of the month. The Board may conduct either a "paper hearing" or an oral hearing in respect of the Application, and is requested to approve the sales rates prior to the commencement of that gas quarter.

The Board has approved three interim Primary Gas rate changes effective August 1, 2000, November 1, 2000, and February 1, 2001 pursuant to the RSM.

8.0 The Application

This application deals only with the Primary Gas cost component of the sales rate on the customer's bill. Centra filed a separate application for a change in Non-Primary gas costs to be effective for all gas consumed on and after June 1, 2001. The Board's decisions on that application are set out in Order 91/01 dated June 6, 2001.

On March 23, 2001, Centra applied to the Board for approval of interim sales rates to be effective June 1, 2001 and to remain in effect until a further Order of the Board. Because the Primary Gas PGVA balance was in excess of $100 million, Centra modified its application from the RSM to deal with the recovery of this unexpectedly large balance.

Because of Centra's requested modification to the RSM, the Board decided that a public hearing was necessary to allow for the appropriate public input. To accommodate the public hearing process, Centra revised their standard application to reflect an implementation date of June 1, 2001 instead of May 1, 2001. Specifically, Centra requested approval of the following:

1. A Primary Gas Base Rate that reflects 50% of the difference between the current 12-month forward price for Western Canadian supplies as of May 8, 2001,weighted for the cost of gas in storage, and the cost of Primary Gas embedded in the current approved sales rates, calculated in accordance with the RSM approved in Board Order 55/00;

2. To transfer the balance of the PGVA as at February 28, 2001 into a separate deferral account, to be called the Deferred Gas Recovery Account ("DGRA");

3. To apply the revenue from the existing Primary Gas Rate Rider for the period March 1, 2001 to May 31, 2001 to the DGRA;

4. A Primary Gas Rate Rider to dispose of the balance of the Primary Gas PGVA that accumulated between March 1 and April 30, 2001 over a 12-month period. This rate rider would only apply to Centra's system customers and Buy/Sell supply customers; and

5. A Deferred Gas Recovery Rider ("DGRR") to dispose of the net balance of the DGRA as at May 31, 2001, over a 24-month period commencing June 1, 2001. This rate rider would apply to all customers, with the exception of the WTS customers of record at February 28, 2001.

A public hearing was held May 14 - 18, 2001 and final argument was heard on May 24, 2001.

9.0 Primary Gas Billed Rate Components

The components of the existing Primary Gas billed rate compared to the components of the proposed June 1, 2001 billed rate, based on the 12-month forward price strip at May 8, 2001, are as follows:

Primary Gas Billing Components	February 1, 2001 Approved Rate ($/cubic metre)	June 1, 2001 Proposed Rate with Deferred Gas Recovery Rider ($/cubic metre)
Primary Gas Base Rate	0.2577	0.2493
Gas Overhead	0.0005	0.0005
TCPL Fuel Component		0.0056
Primary Gas PGVA Rate Rider	0.0340	0.0052
	0.2922	0.2606
Primary Gas DGRR		0.0325
Primary Gas Billed Rate	0.2922	0.2931

9.1 Primary Gas Base Rate

Centra's application for a change in Primary Gas base rate is based on 50% of the change in gas cost, consistent with the RSM, and includes no change to the inclusion rate used in previous filings. Centra stated that modifying the RSM to a 100% inclusion rate and/or monthly updates was market responsive but did not address the magnitude, frequency or oscillation of rate changes, nor was rate volatility necessarily reduced. Centra added that no empirical evidence or research has been provided by any intervenors to support the view that consumers are prepared to accept the volatility associated with monthly rate adjustments.

The current approved Primary Gas Base Rate is $0.2577 per cubic metre. The Application reflects 50% of the change between that amount and the current 12-month forward price for Centra's Western Canadian supplies as at May 8, 2001 of $6.617/Gigajoule ("Gj"), adjusted for Centra's new gas supply contract arrangements with TransCanada Energy Ltd. ("TCE").

At the time of this application, Centra had not placed any forward hedges for volumes related to Western Canadian supplies from May 1, 2001 to April 30, 2002. Centra added that while no transactions have yet been placed for the current gas year, Centra may place transactions in the future. Therefore, the proposed Primary Gas rate, when weighted for storage gas, was $6.595/Gj ($0.2493 per cubic metre) which was $0.223/Gj lower than the $6.818/Gj cost currently embedded in sales rates.

9.2 TCPL Fuel Component

An additional cost component of $0.0056 per cubic metre has been added to the Primary Gas Base Rate commencing June 1, 2001 to reflect fuel costs from Alberta to Manitoba. This component was previously included in the Transportation rate. This component is a reclassification and does not result in any overall rate change for System or Buy/Sell customers.

9.3 Primary Gas Rate Rider

Centra requested approval to implement a rate rider to recover the PGVA balance at May 31, 2001, estimated to be $11.3 million owing to Centra, over the next 12 months

Primary Gas normalized volumes of 1,563,611 thousand cubic metres. Centra calculated the required rate rider to be $0.0052 per cubic metre.

To ensure that the Primary Gas PGVA did not exceed acceptable levels in the future, Centra proposed to monitor the Primary Gas PGVA balance on a monthly basis, and if the balance in the PGVA was expected to exceed $25 million, Centra would advise the Board immediately and suggest an appropriate course of action.

9.4 Primary Gas Deferred Gas Recovery Account ("DGRA")

During proceedings resulting in Order 55/00, Centra provided evidence that the RSM was effective under normal market conditions. However, over the last several months, the natural gas markets have not been normal, and have experienced large increases in the commodity cost of gas. As a result of these market increases, the Primary Gas PGVA has grown to $104.6 million at February 28, 2001.

Centra was of the view that in recovering this unexpectedly large balance, customers that caused the costs in building up the PGVA balance should be responsible for paying those costs. Therefore, recovering the DGRR from all customers was, in Centra's view, the most fair and equitable way to collect the balance. Centra noted that most WTS customers at February 28, 2001 had converted to WTS service prior to November 2000, and that the largest build-up in the PGVA occurred after that time.

Centra therefore requested that the DGRR be based on the transfer of $104.6 million as at February 28, 2001 from the Primary Gas PGVA to the DGRA, and be recovered from all system customers as of that date. Centra also proposed that this balance be reduced by applying the revenue from the existing Primary Gas PGVA rider for the period March 1, 2001 through May 31, 2001. The net balance, adjusted for the inclusion of carrying costs, is estimated at $94.4 million as at May 31, 2001.

The DGRR has been calculated at $0.0325 per cubic metre to amortize the $94.4 million balance over 24 months starting June 1, 2001. Centra proposed that the DGRR will be applied to all customers, with the exception of WTS customers of record as at February 28, 2001. Any system customer who switches to WTS subsequent to March 1, 2001 will be subject to the rider. As well, any WTS customers who subsequently return to Centra's system supply over the course of the 24-month recovery period will be subject to the rider, from the date of their return forward. Centra added that the extension of the rate rider to a 36-month period would decrease rates by only 1.1%. Centra believes that a 3 or 6 month recovery period would also be inappropriate as rate volatility would increase, rate comparisons would not be possible, and seasonal variations in consumption would result in an element of unfairness to customers.

Centra stated that there were approximately 6,200 customers waiting to convert to WTS service as of April 1, and approximately 4,000 customers enrolled between April 1, 2001 and April 30, 2001. In its evidence, Centra provided a number of scenarios to determine the bill impact to remaining system customers if new WTS customers were permitted to leave system supply with no obligation to pay the DGRA. Centra estimated the average residential customer's annual bill would increase by approximately $32 if 71,300 SGS and LGS customers and 40% of the HVF and Interruptible customers, based on volume, were to convert to WTS without responsibility for the DGRA.

Centra proposes to recover the DGRA on a volumetric basis. Centra noted that Primary Gas costs are incurred and recovered strictly on a volumetric basis and supplied to all customer classes on the same unit cost basis. In addition, a significant portion of the Primary Gas PGVA was accumulated in December 2000 and January 2001, at a time when SGC consumption is greater than during summer months. Therefore, allocation of the DGRA by customer class would not be appropriate because it would unfairly increase the amount paid by SGC customers. Centra also stated that billing the DGRR based on average monthly volumes presented a number of administrative difficulties. Centra also pointed out that equal monthly payments were available through the existing Budget Billing Plan.

In considering options to recover the DGRA, Centra did contemplate the use of exit fees. However, Centra rejected this alternative because it was difficult to determine the appropriate fee to be paid by specific customers or customer classes, taking into account factors such as consumption, length of time on the system, and when the balance was accumulated. In addition, customers would be required to make a lump sum payment on exiting the system, which could be onerous for some customers, and could be interpreted as a penalty which might impede the development of WTS.

Centra also considered the use of a recovery rider which would dispose of the deferred balances each quarter to be recovered from all customers except those WTS customers of record at the start of that quarter. This procedure could result in four separate rate riders at any given time. In Centra's view, this procedure would be difficult to understand, and be administratively complex.

Centra acknowledged that there is no guarantee that unusual market circumstances, such as the dramatic market increases witnessed over the last several months, would not occur again. However, a large build-up in the PGVA balance in the future could be prevented if it were closely monitored.

9.5 Evidence of Russell Feingold

Mr. Feingold stated that the RSM is intended to moderate the impact of changes in the cost of Primary Gas and is working as intended. The RSM results in Primary Gas prices that are lower than the market when prices are rising, and higher than the market when prices are falling. Mr. Feingold stated that there is no demonstrated reason to change the fundamental structure of the RSM, and it should be allowed to perform its intended function. He expressed the view that the significant balance in the PGVA at February 28, 2001 is a result of highly unusual and dramatic increases in market prices of gas, and is not the result of any failure of the RSM.

Mr. Feingold stated that the PGVA balance should be recovered from the customers that cause the costs, and customer impacts should be considered when rates are changed. Large PGVA balances are not beneficial to Centra or to its customers. Therefore, the approved Rate Setting Process should include special rules, including the opportunity for a one-time rate adjustment in each quarter if the PGVA balance shows evidence of growing beyond an acceptable limit. The process should allow short lead times to adapt to rapidly changing market conditions. Any such change would be considered at the subsequent quarter to allow for public input and Board review.

10.0 Impact on Rates

Centra calculated customer rate impacts based on the recovery of the PGVA over 12 months, as approved in Order 55/00, as well as the impact of the proposed application which recovers the DGRA over 24 months. The table below summarizes the increases to the annual natural gas bills of different customer classes for each approach.

Annualized Percentage Increase in Customer Bills

	RSM Methodology Approved in 55/00	Proposed Methodology including DGRR
SGS	6.3 to 6.8	0.2 to 0.2
LGS	6.6 to 8.0	0.2 to 0.2
HVF	7.8 to 8.3	0.2 to 0.2
Mainline	8.1 to 8.8	0.2 to 0.3
Interruptible	8.0 to 8.5	0.2 to 0.3

Centra stated that price transparency would be maintained as the DGRR would be a separate line item on the bill and the amount would be clearly visible to both the system and the direct purchase customers. A shorter recovery time would increase market responsiveness. However, due to the unprecedented rise in natural gas prices, which contributed to the extraordinary large PGVA, a longer recovery period will balance the need for market responsiveness with customer sensitivity to rate volatility.

Centra stated that the recovery method was equitable and did not anticipate that brokers' marketing or competition would be adversely impacted by the existence of the DGRR. All customers who caused the balance are affected equally regardless of who supplies their Primary Gas. Customer growth and decline over the proposed two-year recovery period is expected to be minimal. Therefore, potential inter-generational issues would be minimal.

Centra submitted, in response to evidence filed by CAC/MSOS, that the inclusion of the forward price curve on the customers bill would be of questionable value because it would not reflect the impact of hedging, the billing cycle will prevent current market information, and the information on one customer's bill may differ from another depending on the billing cycle. Centra is reviewing the possibility of a quarterly bill insert containing market information to help inform customers.

11.0 Intervenors' Positions

11.1 CAC/MSOS

CAC/MSOS stated that consumers appreciate anything that can be done to minimize the burden associated with the recovery of the PGVA. Therefore, Centra's request to dispose of the DGRA over a two-year period had the full endorsement of CAC/MSOS.

CAC/MSOS recommended that the Board order Centra to recover the DGRA on a customer specific basis. CAC/MSOS submitted that customer specific recovery eliminates virtually all of the inequities identified during this proceeding. CAC/MSOS asked the Board to consider whether the cost of implementing customer specific recovery, estimated to be in the range of $2-2.5 million, provides value if it solves the numerous inequities that result in the current system.

CAC/MSOS' general position is that those who incurred the costs should pay those costs. However, CAC/MSOS submitted that it is clear that the current regulatory scheme did not hold WTS customers accountable for the PGVA balance. Therefore, in the interest of fairness, CAC/MSOS recommended that all customers that had gas flowing under WTS Service as of the date of the Order should be exempt from the DGRR. Customers that do not have gas flowing under WTS Service but have signed contracts should be advised as to the change in rules and given the option to remain with system gas or convert to WTS.

CAC/MSOS strongly disagrees with Centra's contention that the RSM is working and should be retained. In the view of CAC/MSOS, the RSM has been a complete failure. In order to encourage and promote competition for the sale of gas, it is essential that Centra's rate be market responsive. The best mechanism is the one that does not need to be adjusted if the market does not perform as anticipated or expected. Therefore, CAC/MSOS recommended amending the RSM to use a 100% adjustment of the difference between the gas cost included in the existing sales rate, and the current market price, on a monthly basis. CAC/MSOS suggested that a separate hearing be conducted to determine the process for the setting of rates on a monthly basis.

11.1.1 Evidence of John Todd

Mr. Todd provided evidence on behalf of CAC/MSOS, and made the following recommendations:

1. The frequency of updating the Primary Gas rate should be increased from quarterly to monthly.

2. The change in the cost of gas embedded in Primary Gas rates should be increased from 50% to 100% of the difference between the updated 12-month forward price curve (adjusted for the cost of gas in storage) and the sales rate set in the previous quarter.

3. The PGVA balance should normally be cleared over 12 months, with the caveat that the period can be extended to 24, or even 36 months, if the balance is large enough that the rate rider will compromise the market responsiveness of Primary Gas rate. Centra's proposal to recover the DGRA through a 24-month DGRR would be consistent with this policy.

4. Customers that switch to WTS should be required to pay the DGRR, as proposed by Centra.

5. Consideration should be given to implementation of an on-going DGRA/DGRR mechanism if the current RSM is not amended as proposed in the preceding recommendations. However, an on-going DGRA/DGRR is unlikely to be necessary if the frequency of updating the Primary Gas rate and the rate rider is increased to monthly and the Primary Gas rate is adjusted fully to reflect current forecast costs.

6. Rate riders should be billed to customers on the basis of their average monthly volume over the year.

7. Centra should amend its bill format to distinguish between the two Primary Gas lines on the bill by including the dates during which each rate applies.

8. Centra should amend its bill format by showing, in large typeface, the most current forecast of the cost of gas (the updated 12-month forward price curve, weighted for the cost of gas in storage).

Mr. Todd added that recovering the balance of the PGVA/DGRA from only system and Buy/Sell customers would not result in a level competitive playing field. Competitors would have an artificial advantage in that customers could avoid their share of the deferred gas costs by switching to WTS.

Mr. Todd suggested an alternative whereby a DGRR would be calculated each quarter to ensure that customers pay their fair share. However, this alternative would be administratively complex given that more than one rate rider would need to be calculated.

11.1.2 Evidence of Gerard Forget

Mr. Forget provided evidence on behalf of CAC/MSOS, and recommended that the rate rider should be allocated by customer class based on historical volumes. The rate rider should be calculated based on expected future normalized volumes. Each customer class would be responsible for the collection of the PGVA balance allocated to that group. Any customer leaving the system will have to pay an exit fee. Balances in the PGVA related to bankrupt customers would be allocated to all customers under his proposal.

Mr. Forget recommended that 100% of the price changes be included in rates and the adjustment be made once a month, only if the new price reflects an increase or decrease of more than 5%.

11.2 Municipal Gas' Position

Municipal Gas suggested that the Board consider market responsiveness as the first principle in its decision process; the second principle should be price transparency; the third principle should be a need for regulatory stability; and the fourth principle should be the implementation of fair transitional rules to any new RSM for the Primary Gas.

Municipal Gas submitted that the RSM is not accomplishing these principles as established in Order 55/00 and should be amended as follows:

1. Primary Gas rates should be adjusted monthly and incorporate 100% of the cost differential between the current rate and the forecast twelve-month (12) price strip.

2. Any differences between the actual cost and the recovered cost of Primary Gas should be tracked and dealt with in a "Primary Gas Deferral Account." Any deferral account for Primary Gas costs should not be called by a new name such as the DGRA, but should be labelled Primary Gas Deferral Account.

Looking forward, the Primary Gas Deferral Account should be recovered over a shorter time period, say six (6) months, in order to avoid inter-generational inequities and the incurrence of large carrying costs.

In the future, the Primary Gas PGVA should be recovered from customers in one of two ways:

1. From only system customers on the basis that over the long term, migrations to and from system gas and direct purchase would balance each other out and the PGVA balance would be small; or

2. From both system customers and migrating customers who were system customers as of the date of disposition of the PGVA, on the basis that the customers who caused the costs should pay for the costs.

Any new mechanism, special adjustment or rate rider for the Primary Gas PGVA should be avoided. The RSM should be designed to minimize the risk of the accumulation of a large PGVA balance and the need for periodic ad hoc adjustments.

Municipal Gas proposed that any customer who has filed an application with the utility through a broker to migrate to WTS prior to one (1) month following the Board's release of its Order in this proceeding should not be responsible for the DGRR. Municipal Gas submitted that this one (1) month period would allow time to notify consumers of the change, would allow brokers to make any necessary changes to their marketing materials to reflect the Board's decision, and would be fair in that those customers who have filed WTS applications over the last few weeks are not unfairly penalized due to the utility's administrative rule.

Municipal Gas cautioned the Board that if the PGVA reaches a significant level, then the customers' proportionate share of the PGVA could reach punitive levels. A responsibility on departure rule might then be a prohibitive barrier to customers that wish to change their supplier of choice.

Municipal Gas submitted that after May 1, 2000, any customer who left system supply was not held responsible for any amount in Centra's Primary Gas PGVA. While the Board did not specifically write down such a regulatory rule, Municipal Gas was of the opinion that it has been clear from the Application of Order 55/00 that the responsibility for any Primary Gas PGVA balance remained with system gas customers.

Municipal Gas added that in its opinion, the PGVA does not represent a legal debt owed to the utility by departing customers. However, the Board has statutory power to make this balance a legal debt of departing customers.

11.2.1 Evidence of Colin MacMillan, Brian Soutiere, and Karen Melnychuk

Colin MacMillan, Brian Soutiere and KarenMelnychuk provided evidence on behalf of Municipal Gas, and strongly opposed the Application for the following reasons:

1. The creation of the DGRA would represent a major step back from the principles of price transparency advocated by the Board in Order 19/00 and would significantly obscure the transparency of Primary Gas costs;

2. Creating a DGRA would confuse natural gas customers by using a new label to describe costs incurred in the purchase of Primary Gas; and

3. By splitting Primary Gas cost into three categories, competition in the sale of natural gas will be hindered because consumers will not be able to easily make "apples to apple" comparisons between offerings of Centra compared to offerings of licensed ABMs.

The witnesses strongly objected to Centra's proposal to recover the DGRA over a 24-month period from all natural gas customers except WTS customers of record as at

February 28, 2001. The witnesses argued that Centra seeks to overturn the Board's decision in Order 19/00 and apply rate-making principles retroactively.

The witnesses believe that the concerns Centra has voiced about large Primary Gas PGVA balances should be addressed through periodic rate changes which pass on a larger portion of increased gas costs, through more frequent reductions in the Primary Gas PGVA, or through the creation, prospectively, of exit fees which fairly reflect a departing customer's pro rata share of any accumulated amounts in the Primary Gas PGVA.

The witnesses expressed concern about the timing of Centra's application which appears to coincide with marketing campaigns by Municipal Gas to sign up additional WTS customers.

12.0 Presenters' Positions

12.1 A. Cerilli

Mr. Cerilli reminded the Board of the hardships faced by seniors, families, health care organizations, educational organizations and the business community as a result of the increases in heating fuels. Mr. Cerilli was surprised that Centra is before the Board applying for yet another rate increase. He requested that the Board provide some relief to the consumers of natural gas by disallowing Centra's request for a rate increase. He requested that Hydro, Centra and the Board do all they can to find solutions on a national and international basis to manage rising energy prices.

12.2 T. Ducharme

Ms. Ducharme cited the benefits of natural gas and stated that the consumers of Manitoba depend on this fuel. However, the repeated gas rate increases are creating hardships and increasing the stress levels of consumers. By allowing the PGVA to build to its current balance, Centra has added to the problem. She stated that a solution will only be found when all interested parties work together.

12.3 S. Horyski

Ms. Horyski opposed Centra's Application to increase rates. She stated that Manitobans are struggling to pay current gas prices. Consumers have to make choices between purchasing food and medicine, and paying their heating bills. She added that businesses in Manitoba are filing for bankruptcy as a result of the increases in natural gas.
She asked that Centra consider all sources of natural gas, not just Alberta sources. She requested that the Board protect the consumer within the scope of its jurisdiction.

12.4 T. Nicholson

The West Central Natural Gas Committee stated that it had been informed that Centra had requested that new customers be included in paying off the deficit incurred in the deferral account when natural gas prices increased during the winter of 2000/01. He stated that this treatment is not fair because new customers did not contribute to the balance. Being part of a group trying to promote the expansion of natural gas into his region, he was are concerned that this additional cost will make his job more difficult when trying to sign up customers, especially when rates are already considerably higher than they were a year ago. He requested the Board rule against Centra's request.

12.5 K. Silvera

Ms. Silvera was outraged by the recent price increases of natural gas. She stated that many Manitobans will lose their homes and businesses. She urged the Board to take quick action to deal with this issue.

13.0 Board Findings

General

In arriving at its decisions in Order 55/00, the Board accepted Centra's assessment of Rate Setting Methodology ("RSM") alternatives, and agreed with Centra that the proposed RSM was best suited at that time to meet the needs of Centra's customers and the marketplace. It was expected that customers would be exposed to normal market conditions and rate changes, both upward and downward. Nobody expected the severe increases in the market price of natural gas that were experienced during the winter of 2000/2001.

The Board remains of the view that the ability of the customer to see the rate paid for Primary Gas on the bill is a precondition for a competitive market. Price transparency must be a significant consideration of any RSM. The Board also considered market responsiveness to be a primary consideration followed by concern for the frequency and oscillation of rate changes, the magnitude of those rate changes, and finally, simplicity of implementation.

Deferred Gas Recovery Account ("DGRA")

The existing RSM cannot effectively dispose of the large PGVA balance without undue hardship to customers, and additional steps must be taken. As such, the Board will approve Centra's request to establish the DGRA. This account will be comprised of the balance in the PGVA at April 30, 2001, net of any collections from the existing Primary Gas rate rider to May 31, 2001.

The Board accepts the view expressed by Centra, CAC/MSOS and their witnesses that customers who have created the balance in the DGRA should pay a fair share of the balance. As such, the Board will direct Centra to collect the DGRA from all System and Buy/Sell customers as at April 30, 2001, through the implementation of a Deferred Gas Rate Rider ("DGRR"). Only WTS customers of record as of April 30, 2001 will be excluded from the rate rider. A substantial number of these WTS customers were WTS customers prior to the commencement of the heating season, and as a consequence, did not contribute to the build-up of the DGRA balance. As new and returning customers to system supply after April 30, 2001 also did not create the existing DGRA balance, the Board will direct Centra to also exempt these customers from payment of the DGRR.

The Board understands that there were System customers at April 30, 2001 that had signed agreements prior to that date with ABMs to change their supplier for Primary Gas. As these customers contributed to the balance of the DGRA, they should be held responsible for their fair share of the balance to maintain equity and fairness. Municipal Gas gave evidence that these customers will be provided with updated information and given the option to reconsider their decision to change supplier. The Board supports this initiative.

The Board was not convinced that allocating the DGRA balance by customer class would be beneficial to the consumers of Manitoba. The Board remains of the view that the current methodology of recovering amounts from customers based on volumes is most appropriate for the collection of both the DGRA and the PGVA.

The Board is aware of the difficulties Manitobans have faced over the past winter in dealing with rising natural gas prices. The Board is of the view that a 24-month collection period proposed by Centra will help ease the burden of this additional rate rider. The Board will therefore approve collection of the DGRR over a 24-month period, beginning on August 1, 2001 and terminating once the balance is collected, no later than July 31, 2003.

During the hearing, the Board heard evidence that the use of the term "Deferred Gas Recovery Rider" would not allow customers to identify this item as a Primary Gas component. The Board believes the term "Primary Gas Deferral Account" will help reduce the confusion of customers. Therefore, the Board will direct Centra to use this term on customer bills, and all other communications. The Board also encourages Centra to use bill inserts to explain this new item on the customer's bill. The information given should provide the reasons for the implementation of the Primary Gas Deferral Account and explain how it will be collected.

Information regarding market pricing is helpful to customers in making informed choices about their natural gas purchases. The Board recommends that Centra, using bill inserts and other means of communication, provide regular updates to customers regarding the natural gas markets.

Rate Setting Methodology ("RSM")

Because of the dramatic increase in gas prices over the past several months, the use of the 50% inclusion rate was a key factor in the resulting large PGVA balance. Moreover, in rapidly rising or falling markets, the 50% inclusion rate obscures price transparency and market responsiveness, which ultimately has a negative impact on competition in Manitoba. Therefore, the Board will direct Centra to use a 100% inclusion rate in the determination of the August 1, 2001 Primary Gas rate and thereafter.

The use of the 100% inclusion rate should help to prevent future large accumulations in the PGVA. However, the Board wishes to remind Centra that it must monitor this balance closely to prevent large future balances. The Board will monitor the results each quarter in the context of the marketplace.

Under the assumption that the PGVA balance will be small in the future and the inflows and outflows of customers to and from System supply will offset, the Board will direct Centra to collect future PGVA balances from System and Buy/Sell customers.

In order to increase the level of market responsiveness, the Board is of the view that the RSM should include the estimated PGVA balance to the end of the gas quarter going forward. Therefore, the required PGVA rider, to be effective August 1, 2001, should be calculated using the estimated PGVA balance to July 31, 2001.

Monthly updates would increase the market responsiveness of Centra's rates. However, the Board is of the view that this would result in an administratively complex process. Therefore, the Board regards the existing quarterly process as most appropriate at this time.

The Board is of the view that the PGVA balance and market conditions should be monitored on a monthly basis to determine if special action is required. Therefore, the Board will direct Centra to file a report with the Board on a monthly basis indicating the current PGVA balance.

The Board is concerned that the 12-month forward strip may not best indicator of the average cost that will be paid by Centra for the subsequent gas quarter. Therefore, the Board will direct Centra to examine alternatives to this indicator and provide a report detailing these alternatives along with Centra's proposed recommendation to the Board with its next quarterly filing.

Derivative Hedging

As stated in Order 91/01, the Board is concerned that Centra has become dependent on the RSM to manage volatility. The Board encourages Centra to consider derivative hedging transactions to manage volatility as contemplated in its Derivative Hedging Policy.

The Board is of the view that Derivative Hedging transactions do not have to correspond to the gas year. Therefore, the Board encourages Centra to evaluate its hedging options on an ongoing basis.

Bill Stability

The natural gas market can be subject to large fluctuations in the commodity price. With a move to a 100% inclusion rate, these price fluctuations will be passed through to Centra's sales rates, and customers might experience more volatility in their monthly gas bills. However, customers can achieve a degree of bill stability through the use of Centra's Budget Billing Plan.

The Board encourages Centra to continue to promote the use of the Budget Billing Plan to customers. The Board sees bill inserts as the best medium to communicate this option, but cautions Centra that these inserts must be generic, factual and not impede competition in the Manitoba Primary Gas market.

14.0 It Is Therefore Ordered That:

1. The Application by Centra for an interim order approving Primary Gas sales rates to be effective for all gas consumed on and after June 1, 2001 BE AND IS HEREBY DENIED.

2. Existing Primary Gas sales rates shall remain in effect until August 1, 2001.

3. Centra shall transfer the balance of the Purchased Gas Variance Account ("PGVA") as at April 30, 2001 into a separate account, to be called the Primary Gas Deferral Account, net of collections from the existing Primary Gas Rate Rider to May 31, 2001;

4. Centra shall determine a Primary Gas Deferral Account Rate Rider to dispose of the net balance of the Primary Gas Deferral Account over a 24-month period commencing August 1, 2001. This rate rider will apply to all customers, with the exception of WTS customers at April 30, 2001;

5. Centra shall determine Primary Gas base rates to be effective August 1, 2001 to reflect 100% of the difference between the current 12-month forward price for Western Canadian supplies, weighted for the cost of gas in storage, and the cost of Primary Gas embedded in the current approved Primary Gas sales rates;

6. Centra shall determine the Primary Gas Rate Rider to be effective August 1, 2001 to dispose of the estimated balance in the Primary Gas PGVA that accumulated between May 1, 2001 and July 31, 2001, net of collections from the existing Primary Gas Rate

Rider from June 1, 2001 to July 31, 2001, over a 12-month period. This rate rider will apply to Centra's system customers and Buy/Sell supply customers;

7. Centra shall file a report on a monthly basis indicating the current Primary Gas Purchased Gas Variance Account balance and the current Primary Gas Deferral Account balance.

8. At the next quarterly rate application, Centra shall file a report with the Board that details alternatives to the use of the 12-month forward price for Western Canadian supplies, including a proposed recommendation.

THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"G. O. Barron"
Secretary

Certified a true copy of
Order No. 99/01 issued by
The Public Utilities Board

Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY
ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

EB-2007-0905

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

NOVEMBER 3, 2008

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F- Memorandum of Agreement between OPG and the Province of Ontario

1 INTRODUCTION

This proceeding concerned an application by Ontario Power Generation Inc. (OPG) under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B) (*OEB Act*) requesting Board approval for payment amounts with respect to six hydroelectric generating stations and three nuclear generating stations owned and operated by OPG.

This was an unusual proceeding in at least two respects. First, until now the Board has not regulated the prices charged by electricity generators in Ontario. Second, regulations under the *OEB Act* constrain in some important respects the scope of the Board's consideration of OPG's application as compared to the scope of the Board's hearings on rates charged by transmitters and distributors.

This chapter briefly describes the generation facilities in question and summarizes OPG's application. It also describes the legislative framework that governs the Board's setting of payment amounts for OPG's facilities and how that framework affected this proceeding.

Details of the procedural aspects of this proceeding are contained in Appendix A.

1.1 The Prescribed Generation Facilities

OPG requested that the Board approve payment amounts for nine generating stations. These facilities, and their nameplate capacities, are listed in Table 1-1. These plants are referred to as the "prescribed generation facilities" under regulations to the *OEB Act*, and that term is used extensively in this decision. (OPG's other generating facilities are unregulated, including various hydroelectric and fossil fuel stations.)

The nine generating stations have a combined capacity of 9,938 MW, or about 45% of OPG's total generation capacity. The Sir Adam Beck Pump Generating Station, which is integrated with the Beck complex, provides the bulk of the peaking capability from OPG's regulated facilities. The other plants are "baseload" facilities although the other hydroelectric facilities have some minor peaking capability.

Table 1-1: Prescribed Generation Facilities

Hydroelectric		Nuclear	
Station	**Capacity**	**Station**	**Capacity**
Sir Adam Beck I	447 MW	Pickering A NGS	1,030 MW
Sir Adam Beck II	1,499 MW	Pickering B NGS	2,064 MW
Sir Adam Beck Pump Generating Station	174 MW	Darlington NGS	3,512 MW
DeCew Falls I and II	167 MW		
R.H Saunders	1,045 MW		
Total	**3,332 MW**		**6,606 MW**

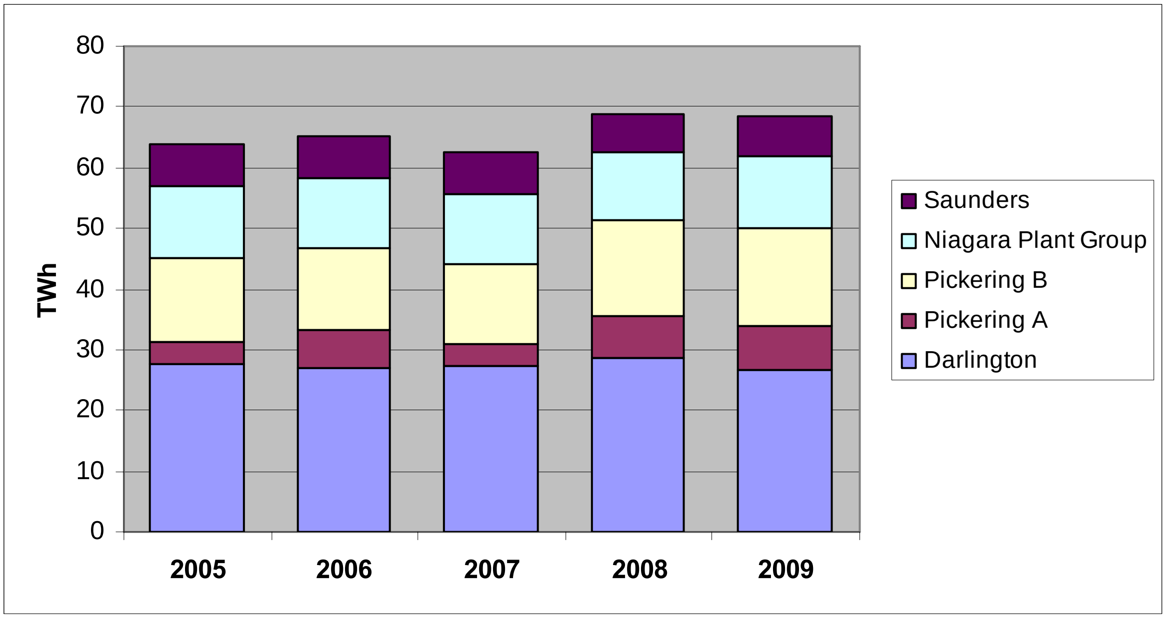
The prescribed hydroelectric generation facilities are owned directly by OPG and are not held in a subsidiary or other separate legal entity. The nuclear stations are held in wholly-owned subsidiaries of OPG. The prescribed facilities essentially are operated as two divisions of OPG – Regulated Hydroelectric and Regulated Nuclear.

From the opening of the Ontario wholesale power market on May 1, 2002 until March 31, 2005, the price charged by OPG for output from these plants was not subject to regulation by either the government of Ontario or the Board. OPG sold output from these plants into the hourly market operated by the Independent Electricity System Operator (IESO) and received the market price. The company was obligated, however, to make rebates to consumers pursuant to a Market Power Mitigation Agreement (MPMA), which had the effect of constraining OPG's total revenues.

Effective April 1, 2005, the government of Ontario eliminated the MPMA rebate mechanism. Amendments to the *OEB Act* gave the government the authority to set prices for output from the prescribed facilities. The payment amounts were set at $33.00 per mega-watt hour (MWh) for hydroelectric production up to 1900 MWh per hour, with market pricing for hydroelectric production greater than 1,900 MWh in any hour. The payment for nuclear output was set at $49.50 per MWh. OPG continues to offer the output of these plants into the IESO market but the amounts paid monthly to OPG by the IESO are based on the regulated payment amounts, not hourly spot market prices.

The prescribed facilities generate a significant portion of Ontario's electrical energy. Production for the past three years and forecast production for 2008 and 2009 are shown in Chart 1-1. (The Niagara Plant Group is comprised of the Beck and DeCew Falls plants.) In 2007, the nine stations generated 62.4 terra-watt hours (TWh) of electrical energy, or over 40% of the electrical energy used by Ontario consumers.

Chart 1-1: Actual and Forecast Energy Production



Sources: Ex. E1-1-2, Table 1; Ex. E2-1-1, Tables 2a and 2b.

OPG is subject to the terms of a Memorandum of Agreement (MOA), dated August 17, 2005, with the Province that sets out the Province's expectations regarding OPG's mandate, governance, performance, and communications. Key aspects of the MOA include:

- OPG has a commercial mandate, and is to operate on a financially sustainable basis and maintain the value of its assets for its shareholder.
- OPG's key nuclear objective is to reduce the risk exposure to the Province arising from its investment in nuclear generating stations.
- OPG is to seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU reactors worldwide as well as against the top quartile of private and publicly-owned nuclear generators in North America.

The MOA is attached as Appendix F to this decision.

1.2 OPG's Application

Section 78.1 of the *OEB Act* requires that the payment amounts set by the regulation stay in effect until the later of (i) March 31, 2008, and (ii) the effective date of the Board's first order.

In its application, which was filed November 30, 2007, OPG requested that the Board set new payment amounts based on a 21-month test period from April 1, 2008 to December 31, 2009. The new payment amounts proposed by OPG are based on a forecast cost-of-service methodology. OPG also sought an interim order from the Board for increased payment amounts effective April 1, 2008.

In February 2008, the Board held a hearing on OPG's request for an interim order. The Board did not grant OPG's request for increased payments on an interim basis but it did order that the current payment amounts be made interim as at April 1, 2008. Given the provisions of Section 78.1 of the *OEB Act* and the related regulation O. Reg. 53/05, a direct result of the Board's decision to make the current payment amounts interim was that the effective date of the Board's first order under Section 78.1 would be April 1, 2008.[1] Although that decision set the effective date as April 1, 2008, it was not necessary at that time for the Board to determine whether the new payment amounts would be the same as, or different from, the existing payment amounts. The issue of the implementation for new payment amounts remained outstanding and is addressed in Chapter 10.

OPG's proposed revenue requirement and revenue deficiency are summarized in Table 1-2. OPG's proposed revenue requirement is approximately $6.4 billion for the 21-month test period. If the current payment amounts were to stay in place until December 31, 2009, OPG estimated that the prescribed facilities would generate $5.4 billion of revenue for the 21-month period, about $1 billion less than OPG claims it requires. OPG has asked for increases in the payment amounts for the prescribed facilities to offset a large part, but not all, of that revenue deficiency. The company proposed a mitigation measure that would reduce the deficiency by $228 million, and asked for new payment amounts that would cover the remaining estimated deficiency of $798 million.

[1] The Board's oral decision is at pages 111 to 118 of the transcript, "EB-2007-0905, Motion for Interim Order, February 7, 2008" and is reproduced in Appendix C.

Table 1-2: OPG's Proposed Revenue Requirement

$ millions	Hydroelectric			Nuclear			Test Period Total
	2008	2009	Test period	2008	2009	Test period	
	9 months	12 months	21 months	9 months	12 months	21 months	
Expenses							
OM&A	$ 93.1	$ 119.0	**$ 212.0**	$ 1,587.7	$ 2,078.7	**$ 3,666.4**	**$ 3,878.4**
Gross revenue charge/nuclear fuel	179.9	244.1	**423.9**	125.7	204.2	**329.9**	**753.8**
Depreciation and amortization	47.1	63.2	**110.3**	221.5	316.4	**537.9**	**648.2**
New nuclear build/refurbishment	-	-	**-**	75.0	90.0	**165.0**	**165.0**
Property and capital taxes	6.5	8.7	**15.2**	16.3	22.0	**38.4**	**53.6**
Income taxes	-	-	**-**	-	-	**-**	**-**
Cost of Capital							
Short-term debt	5.8	6.0	**11.8**	5.2	5.4	**10.6**	**22.4**
Long-term debt	65.4	91.5	**156.9**	59.2	82.4	**141.5**	**298.4**
Return on equity	175.7	233.6	**409.3**	158.9	210.3	**369.2**	**778.5**
Other Revenue							
Ancillary and other	(24.3)	(33.1)	**(57.4)**	(49.4)	(50.9)	**(100.3)**	**(157.7)**
Bruce NGS (net)	-	-	**-**	(51.8)	(82.6)	**(134.3)**	**(134.3)**
Deferral, variance account recovery	(1.2)	(1.6)	**(2.8)**	55.7	72.5	**128.2**	**125.4**
Revenue Requirement	**548.0**	**731.4**	**1,279.3**	**2,204.1**	**2,948.4**	**5,152.5**	**6,431.8**
Forecast Revenue Based on Current Payment Amounts	427.1	611.1	**1,038.2**	1,897.7	2,470.2	**4,367.9**	**5,406.1**
Revenue Deficiency	120.9	120.3	**241.1**	306.4	478.2	**784.6**	**1,025.7**
Mitigation			**(90.1)**			**(137.9)**	**(228.0)**
Revenue Deficiency, net of mitigation			**$ 151.0**			**$ 646.7**	**$ 797.7**

Sources: Ex. A1-3-1, Tables 1 and 2; Ex. J1-2-1, Tables 2 and 3; Ex. F2-2-2, Table 1; Ex. K1-1-1, Table 3; Ex. K1-2-1, Table 1; Ex. K1-3-1, Table 1.

The principal reasons cited by OPG for the significant revenue deficiency are:

- **Capital structure/return on equity** – OPG proposed a deemed capital structure of 42.5% debt and 57.5% equity (current payment amounts are based on a capital structure of 55% debt and 45% equity). OPG also requested an increase in the return on equity to 10.5% from the 5% that was used to set current payment amounts. This issue is addressed in Chapter 8.
- **Rate base** – A higher rate base due largely to an increase at the end of 2006 in nuclear waste management and decommissioning liabilities. This issue is addressed in Chapter 5.

- **Operating expenses** – Increased operations, maintenance and administrative (OM&A) expense for the nuclear facilities, increased nuclear fuel expense, and the inclusion of interest expense on other post-employment benefit obligations, which was not included when the current payment amounts were set. This issue is addressed in Chapter 2.

Table 1-3 sets out the payment amounts proposed by OPG compared to current amounts. (Per MWh amounts and percentage increases in Table 1-3 are calculated assuming the new payments went into effect on April 1, 2008.)

Table 1-3: Proposed Payment Amounts

($ per MWh except fixed payment)	Hydroelectric	Nuclear
Current	**$33.00**	**$49.50**
Proposed		
Fixed payment	-	$1,221.6 million
Variable	$37.90	$41.50
Deferral account rate rider	-	$1.45
Net effective rate	**$37.90**	**$56.85**
% increase	**14.8%**	**14.9%**

OPG estimated that the proposed new payment amounts would increase the commodity portion of the bill by 5.1% for a typical Ontario electricity customer consuming 1,000 kWh per month.

The company proposed that it continue to charge only a per MWh amount for output from the hydroelectric facilities. OPG proposed a change to the incentive mechanism under which it receives market prices for some of the output from the hydroelectric plants. This issue is addressed in Chapter 3.

OPG proposed a new payment structure for the nuclear facilities, which would provide OPG with $1.2 billion over the test period (payable in equal monthly instalments) irrespective of the amount of energy produced by the nuclear plants. As a result of this fixed payment, the variable charge for nuclear output would decline from $49.50 to $41.50 per MWh, or to $42.95 per MWh if the nuclear deferral account rate rider is included. Under the current 100% variable payment structure, OPG would need to charge $56.85 per MWh ("net effective rate" in Table 3) to collect its proposed nuclear revenue requirement. This issue is addressed in Chapter 9.

The complete list of approvals sought by OPG is contained in Appendix B.

1.3 Legislative Requirements and Scope of Board Review

This is the first time the Board has set prices for an electricity generator. The Board has considerable experience in setting rates for electricity and natural gas distributors and transmitters that are, in substance if not legally, monopoly providers of energy delivery services. The electricity generation business in Ontario, however, is very different from distribution and transmission of electricity and gas. For example, there is no "market" for distribution of electricity to homes and businesses but there is a market in the electricity commodity that is produced by OPG and other generators. And, unlike the electricity and natural gas distributors that are subject to rate regulation, generators do not have an "obligation to serve."

Given that this is a new activity for the Board, and in light of the differences between the electricity generation and energy delivery businesses, the Board determined that it needed to carefully consider the appropriate regulatory methodology before OPG filed an application. In 2006, the Board consulted with consumer groups, electricity retailers, generators (including OPG), and other stakeholders on a variety of possible regulatory approaches. In the end, the Board determined that it would use a cost-of-service methodology to set the initial payment amounts for the prescribed generation facilities.[2] It left open the possibility of using an incentive regulation mechanism for subsequent payment orders.

Section 78.1(1) of the *OEB Act* establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1(4) states: "The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment."

[2] EB-2006-0064, Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.,* November 30, 2006.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* [3] (O. Reg. 53/05) provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed rules that govern the determination of some components of the payment amounts.

O. Reg. 53/05 affects the setting of payment amounts in three significant ways:

- It requires OPG to establish certain deferral and variance accounts and requires the Board to ensure recovery of the balances, subject to conditions in some cases;
- It requires the Board to ensure OPG recovers costs incurred and firm financial commitments related to certain activities. This requirement extends to costs and revenues of activities that are not related to the ongoing operation and maintenance of the prescribed facilities.
- It requires the Board to accept, in making its first order under section 78.1, certain financial values as set out in OPG's audited financial statements.

Each of these items is discussed below.

1.3.1 Transitional deferral and variance accounts

The initial version of O. Reg. 53/05, which was released in February 2005, required OPG to establish five variance accounts and one deferral account for the period up to the date of the Board's first order. Two additional transitional deferral accounts were added through amendments to the regulation in 2007 and 2008. The transitional accounts are listed in Table 1-4.

According to OPG, the total balance of all transitional variance and deferral accounts as at December 31, 2007, including some accounts that are not explicitly authorized by O. Reg. 53/05, is $339.3 million. These accounts are discussed in Chapter 7 of this decision.

[3] O. Reg. 53/05, *Payments Under Section 78.1 of the Act*, made February 16, 2005 and amended June 6, 2005, February 7, 2007, and February 13, 2008. O. Reg. 53/05 is reproduced in Appendix E.

O. Reg. 53/05 constrains the scope of the Board's review of the transitional variance and deferral account balances. For all accounts, the regulation sets the rate to be used to record interest on the balances, specifies the maximum recovery periods, and requires that the balances be recovered on a straight-line basis. For some accounts the regulation provides the Board with discretion to evaluate the prudence of the costs. In other cases, the Board is required to accept the account balances as set out in OPG's December 31, 2007 audited financial statements.

Table 1-4: Transitional Variance and Deferral Accounts per Regulation 53/05

Account	Reg. 53/05 Reference	OEB Discretion to Evaluate Prudence?
Differences in hydroelectric electricity production due to differences between forecast and actual water conditions	5(1)(a)	Yes
Unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities	5(1)(b)	Yes
Changes in revenues for ancillary services	5(1)(c)	Yes
Acts of God, including severe weather events	5(1)(d)	Yes
Transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules	5(1)(e)	Yes
Non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station[4]	5(4)	No
The revenue requirement impact of any change in OPG's nuclear liabilities resulting from a reference plan approved after April 1, 2008[5]	5.1	No
Costs incurred on or after June 13, 2006 in the course of planning and preparation for new nuclear facilities[6]	5.3	Yes

The only significant interpretation issues in respect of transitional accounts related to the Section 5.1 account, the revenue requirement impact of a change in nuclear

[4] In February 2007, the regulation was amended to allow OPG to include in this account costs related to Units 2 and 3 at Pickering A, which OPG's board of directors had determined would not return to service.

[5] Effective December 31, 2006, OPG recorded a significant increase in its nuclear decommissioning and waste management liabilities pursuant to a new approved reference plan under the Ontario Nuclear Funds Agreement. In February 2007, O. Reg. 53/05 was amended to require OPG to establish a transitional nuclear liability deferral account to record the revenue requirement impact of this change.

[6] The transitional nuclear development deferral account was authorized pursuant to a February 2008 amendment to Regulation 53/05.

liabilities. The issues were how the "revenue requirement impact" should be determined and whether the regulation permits OPG to include in the account costs arising from a change in the nuclear liabilities related to the Bruce nuclear generating stations. That issue is addressed in Chapters 5 and 6 of this decision.

1.3.2 Continuing deferral and variance accounts

The regulation requires that OPG establish three variance or deferral accounts to capture certain costs incurred on and after the effective date of the Board's first order. The three required accounts are:

- Section 5(4) – Pickering A return to service deferral account (continuation of transitional account);
- Section 5.2 – Nuclear liability deferral account to capture the revenue requirement impact of changes in OPG's nuclear liabilities arising from new approved reference plans; and
- Section 5.4 – Nuclear development variance account to capture differences between (a) actual non-capital costs incurred by OPG in the development of proposed new nuclear facilities, and (b) the amount of any such non-capital costs included in the payments set by the Board.

As with the transitional deferral and variance accounts, O. Reg. 53/05 specifies the method and maximum period of recovery. The interest rate on the accounts is to be set by the Board.

In addition to these accounts, OPG has requested Board approval for several other deferral and variance accounts, as discussed in Chapter 7 of this decision.

1.3.3 Assured recovery of certain costs and firm financial commitments

In addition to the requirements related to recovery of variance and deferral accounts, O. Reg. 53/05 also directs the Board to ensure OPG recovers certain other costs. The relevant sections of the regulation are reproduced below.

6(2)4 – Costs to increase output from or to refurbish prescribed facilities
The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

i.if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

ii.if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

6(2)4.1 – New nuclear development
The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

6(2)8 – Revenue requirement impact of nuclear decommissioning liability
The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

6(2)9 – OPG's costs related to the Bruce nuclear generating stations
The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

6(2)10 – Bruce Revenues in Excess of Costs
If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2 [Pickering A, Pickering B, Darlington].

Two of the categories listed above (new nuclear development, and the revenues and costs of the Bruce nuclear stations) are for costs that are not related to the prescribed facilities. Thus, O. Reg. 53/05 requires the Board to take into account costs and revenues of unregulated activities when setting payment amounts for regulated activities.

Issues that arose in the hearing on these sections of the regulation included: the method to be used to determine the "revenue requirement impact" of nuclear decommissioning and waste management liabilities (Chapter 5); the method of determining OPG's revenues and costs related to the Bruce nuclear stations (Chapter 6); and, whether Section 6(2)4 permits OPG to recover non-capital costs incurred before April 1, 2008 (Chapter 7).

1.3.4 Acceptance of certain values in OPG's 2007 financial statements

O. Reg. 53/05 requires that, in making its first order, the Board accept certain financial values set out in OPG's audited financial statements. Sections 6(2)5 and 6(2)6 of the regulation state:

> 5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
>
> i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
>
> ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
>
> iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
>
> 6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
>
> i. capital cost allowances,
>
> ii. the revenue requirement impact of accounting and tax policy decisions, and
>
> iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

The most recent audited financial statements approved by OPG's Board of Directors are as at and for the year ended December 31, 2007.

OPG identified the amounts in the 2007 audited financial statements that it believes the Board must accept. A summary of OPG's submission is shown in Table 1-5.

Table 1-5: OPG's Position on Financial Statement Amounts That the Board Must Accept

Description	Amount *($ millions)*	Impact on Payment Amounts
Assets		
Fuel Inventory	$231	Opening rate base
Materials and supplies	420	Opening rate base
Fixed assets in service	7,901	Opening rate base; depreciation expense for prescribed facilities and Bruce
Construction work in progress	509	Addition to rate base during test period
Net regulatory assets	356	Deferral/variance account recovery
Liabilities		
Long-term debt	4,065	Deemed interest expense in test period
Deferred revenue	132	Bruce NGS revenue during test period
Regulatory liabilities	14	Deferral/variance account recovery

Source: Exhibit 2.7.

Under OPG's interpretation of these sections of O. Reg. 53/05, the Board has very little discretion in determining the amount of OPG's rate base. The rate base proposed by OPG is based mainly on amounts that OPG submits the Board must accept (fixed assets, inventory, material and supplies at December 31, 2007), and a significant portion of additions to rate base during the test period are made up of costs that are classified as construction work in progress in the 2007 financial statements.

The following chapters in this decision cover the major issues addressed in this proceeding – nuclear and hydroelectric OM&A and capital expenditures, nuclear waste management and decommissioning liabilities, revenues and costs related to OPG's lease of the Bruce nuclear generating stations, deferral and variance accounts, cost of capital, and the design of the payment amounts. As is evident in these chapters, O. Reg. 53/05's requirements on deferral accounts, assured cost recovery, and acceptance of financial statement amounts were relevant to the Board's deliberation and findings on most of the major issues in this case.

1.4 General Approach to Statutory Interpretation

As stated previously in this chapter, Section 78.1(1) of the *OEB Act* establishes the Board's authority to set the payment amounts for the prescribed generation facilities, and Section 78.1 (4) requires, among other things, that the Board shall make an order under that section in accordance with the rules prescribed by the regulations. O. Reg. 53/05 includes detailed rules that govern the determination of some components of the payment amounts.

When interpreting Section 78.1 and O. Reg. 53/05, the Board applied the modern principle of statutory interpretation cited and adopted by the Supreme Court of Canada,[7] and referred to by Board staff in its legal submissions:

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context, in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament.[8] (the "modern principle")

Board staff's legal submissions concerning the principles of statutory interpretation and the relevant statutory framework were not challenged by any party, and were accepted and relied upon by the Board.

In addition, the Board relied upon *Monsanto Canada Inc*. v. *Superintendent of Financial Services* and *Biolyse Pharma Corporation* v. *Bristol-Myers Squibb*, in which the Supreme Court of Canada discussed and applied the modern principle to the interpretation of regulations.

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[7] The Supreme Court of Canada has cited the modern principle in such cases as *Monsanto Canada Inc*. v. *Superintendent of Financial Services* [2004] 3 S.C.R. 152 and *Biolyse Pharma Corporation* v. *Bristol-Myers Squibb* [2005] 1 S.C.R. 533.

[8] Board Staff Submissions, p. 3. citing Ruth Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed.), Butterworths (Toronto), 2002, p.1.

1.5 Summary of Board Findings

The Board has reduced OPG's requested revenue requirement in a number of areas. The following list summarizes those adjustments; the details of the findings are contained in the subsequent chapters of this decision:

- A reduction in Base OM&A for the Pickering A nuclear station
- A reduction in nuclear advertising expense
- An increase in the revenue attributable to various activities in the hydroelectric business (segregated mode operation and water transactions)
- A reduction in the revenue requirement related to the nuclear waste management and decommissioning liabilities
- A reduction in the deemed equity ratio from the proposed level
- A reduction in the return on equity to 8.65% from the proposed level of 10.5%
- An increase in the revenue attributable to the Bruce nuclear station
- An increase in the revenue requirement due to adjustments to the balances in various deferral and variance accounts and an adjustment to the proposed recovery period for one account
- A reduction in the level of mitigation to be provided by OPG

OPG applied for a total revenue requirement of $6,203.8 million for the 21 month period. The Board does not yet have all of the data necessary to establish the final revenue requirement. Based on the data the Board does have, the Board estimates that the revenue requirement will be approximately $6,017 million for the 21 month period. The Board further estimates that the resulting impact will be an approximate 8.5% increase in the per MWh payment amounts.

2 NUCLEAR FACILITIES

OPG operates by far the largest nuclear fleet in Canada and one of the largest in North America. OPG's prescribed nuclear facilities – Pickering A, Pickering B and Darlington – have a combined generating capacity of 6,606 MW, or twice the capacity of the company's prescribed hydroelectric facilities.

This chapter deals with issues related to the prescribed nuclear facilities –the nuclear production forecast, operating, maintenance and administration expenses (OM&A), capital expenditures, fuel costs, and other revenue. This chapter also addresses costs related to new nuclear facilities and the possible refurbishment of existing nuclear units.

2.1 Production Forecast

Forecast nuclear production is 51.4 TWh for 2008 and 49.9 TWh for 2009. For the 21-month test period, forecast production is 88.2 TWh. Actual and forecast production for the prescribed nuclear facilities are set out in Table 2-1.

Table 2-1: Nuclear Production (TWh)

	2005	2006	2007	2008 Forecast	2009 Forecast
Nuclear stations:					
Darlington	27.6	27.0	27.2	28.6	26.6
Pickering A	3.6	6.4	3.6	7.1	7.3
Pickering B	13.9	13.5	13.4	15.7	16.0
Total - Nuclear stations	**45.1**	**46.9**	**44.2**	**51.4**	**49.9**
Unit capacity factor (%)	83.8	81.5	77.1	88.7	86.2
Planned outages (days)	345.8	323.5	331.2	254.1	343.4
Forced extensions of planned outages (days)	39.8	167.0	131.2	-	-
Forced loss rate (%)	5.4	6.4	11.7	5.1	4.2

Source: Ex. E2-1-1, Table 1

OPG's forecast of nuclear production starts with the assumption that all units run every hour of the year at a 100% capacity factor. From that full capacity output of approximately 58 TWh, OPG deducts production that will not occur due to planned outages and an estimate of forced production outages. OPG also deducts a fleet uncertainty adjustment, typically 0.5 TWh (around 1% of forecast production), to bring the fleet level production to within acceptable confidence limits.

OPG is not seeking a variance account for deviations between actual production and forecast. Accordingly, any variance of the forecast from actual production will be OPG's risk.

None of the intervenors objected to OPG's forecast although Energy Probe Research Foundation (Energy Probe) argued that, given OPG's past performance, the Board should be skeptical of the production forecasts and the estimated forced loss rates (FLR). OPG responded that history does not necessarily repeat itself and that OPG has taken measures to improve its production performance. OPG further claimed that while the production target is challenging, this forecast will incent the organization to achieve maximum generation while ensuring safe and reliable operation.

OPG also questioned submissions by Board staff that the fleet level uncertainty adjustment factor does not reflect historical performance. OPG replied that unplanned outages are properly captured by the FLR, not the fleet level uncertainty adjustment.

Board Findings

Except for forecast production for the Pickering A station, OPG's forecast nuclear production is line with its past experience. Darlington production is expected to fall off slightly in 2009 due to a required four-unit outage for vacuum building inspection.

OPG is forecasting substantially higher production from the two Pickering A units than occurred during 2005 to 2007. OPG expressed confidence in its ability to achieve a higher capacity factor at Pickering A. The Board notes that OPG will be at risk if actual production is less than forecast.

The Board accepts the OPG forecast of nuclear production of 88.2 TWh and directs that OPG use that amount to derive the nuclear payment amount for the test period.

2.2 Operating, Maintenance and Administration Costs

OPG forecast total OM&A costs of $2,184.6 million for 2008 and $2,168.7 million for 2009. Table 2-2 shows the components of actual and forecast nuclear OM&A. Those amounts include forecast OM&A costs of $100 million in 2008 and $90 million in 2009 related to preparatory work on new nuclear facilities and the possible refurbishment of existing units. Those costs, which are subject to specific provisions in O. Reg. 53/05, are not related to the operations of the prescribed facilities. The new generation development and refurbishment OM&A costs are shown separately in Table 2-2 and are addressed in section 2.6 of this decision.

Table 2-2: Total OM&A Expenses

$ millions	2005 [9]	2006	2007	2008 Forecast	2009 Forecast	CAGR 2005-2009
Base OM&A (see Table 2-3)	$1,035.1	$1,122.3	$1,181.6	$1,260.8	$1,278.0	5.4%
Project OM&A	155.9	142.0	111.6	144.6	137.1	-3.2%
Outage OM&A	163.0	187.7	215.6	192.2	207.9	6.3%
Allocation of corporate costs[10]	356.2	423.2	446.8	457.0	430.2	4.8%
Asset service fee	14.7	30.8	33.2	29.9	25.5	14.8%
Total OM&A (before new generation development)	**$1,724.9**	**$1,906.0**	**$1,988.8**	**$2,084.5**	**$2,078.7**	**4.8%**
New generation development/ refurbishment	1.3	11.5	35.0	100.0	90.0	
Total OM&A	**$1,726.5**	**$1,917.5**	**$2,023.8**	**$2,184.5**	**$2,168.7**	**5.9%**

Sources: Ex. F2-1-1, Table 1; F2-2-1, Table 1.

Base OM&A, which accounts for 60% of total OM&A, includes costs incurred at the three nuclear stations as well as the costs of common nuclear support divisions, nuclear services, and waste and transportation services.

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[9] 2005 total excludes impairment charges and write-offs related to Pickering A, Unit 2.

[10] The allocation of corporate costs is addressed in Chapter 4 of this decision.

The components of actual and forecast Base OM&A are set out in Table 2-3 below. Over the period 2005 to 2009, the Base OM&A expenses for Darlington increase at an average annual compound rate of 6.7%, compared to 3.9% for Pickering A and 2.8% for Pickering B.

Table 2-3: Base OM&A (excluding new generation development and refurbishment)

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast	CAGR 2005-2009
Nuclear stations:						
Darlington	$ 243.1	$ 278.6	$ 294.6	$ 311.2	$ 314.9	6.7%
Pickering A	172.9	169.5	177.1	197.7	201.3	3.9%
Pickering B	246.9	263.2	272.7	278.6	275.7	2.8%
Total - Nuclear stations	662.8	711.3	744.5	787.5	791.9	4.5%
Nuclear support divisions	341.2	371.0	393.2	414.0	424.0	5.6%
Nuclear services[11]	26.9	35.5	39.1	54.1	56.6	20.4%
Waste and transportation services	4.2	4.5	4.8	5.3	5.6	7.5%
Total Base OM&A	**$ 1,035.1**	**$ 1,122.3**	**$ 1,181.6**	**$ 1,260.9**	**$1,278.0**	**5.4%**

Source: Ex F2-2-1, Table 1

Forecast Project OM&A costs include $5.1 million for the possible Pickering B Refurbishment (which is addressed in section 2.6 of this decision), $40.6 million for work to isolate Pickering A units 2 and 3 (P2/P3 isolation project), $58.4 million for Infrastructure, and $52.2 million for listed work awaiting release approval. The P2/P3 isolation project involves moving, isolating or repositioning safety or control systems that are required for the continued operation of Pickering A units 1 and 4 after the safe storage of Pickering A units 2 and 3.

Outage OM&A represents incremental costs necessary to complete planned outages, including forced extensions of planned outages. They include costs for overtime, non-regular labour, augmented services, materials, other purchased services and the costs of Inspection and Maintenance Services.

The Asset Service Fee is Nuclear's share of the costs of the fixed assets that are centrally held by OPG, but that are used to provide services for the regulated nuclear

[11] The nuclear services category includes indirect costs of staff working on refurbishment programs.

and hydroelectric businesses. These fixed assets include OPG's head office, the Kipling Building complex, and OPG-wide IT systems and applications.

The Corporate Costs component of OM&A, with the exception of the nuclear advertising element, is addressed in Chapter 4 of this decision.
Board staff and several intervenors questioned the amount of forecast OM&A costs on three grounds. These were (i) the substantial increase in costs between 2005 and 2009; (ii) the increase in labour costs; and (iii) the poor benchmarking of productivity performance. Each is considered in turn.

Increases in total OM&A, 2005 to 2009
For the period 2005 to 2009, the increase in total OM&A costs is forecast to be $442.5 million, a growth of 6.4% per year based on simple average (or 5.9% per year on a compound basis as indicated in Table 2-2).

The School Energy Coalition (SEC) submitted that the annual escalation over the 2005 to 2009 period should be limited to 3% per year which would reduce the proposed OM&A budgets by $284 million in 2008 and $217 million in 2009. CME proposed the total increase be restricted to 6% above 2007 OM&A costs, the rationale being the recent OEB-approved incentive rate adjustments of less than 2% per year for Enbridge Gas Distribution and Union Gas.

OPG responded that using 2007 as a base year ignored the significant cost impact of spending on nuclear generation development during the test period ($100 million in 2008 and $90 million 2009 as shown in Table 2-2). OPG submitted that the arguments of SEC and CME failed to recognize the unique cost drivers during the period. These included safety requirements of the Canadian Nuclear Safety Commission and vacuum building outage preparation at both Darlington and Pickering, as well as new reliability improvement initiatives at Pickering.

OPG also pointed out that of the $331.6 million increase in Base OM&A between 2005 and 2009, $165 million was due to labour escalation and of the remaining $166 million, $88 million was for new generation development. Approximately $39 million was for security and other improvements in nuclear training. OPG noted that labour costs constitute 74% of OPG's nuclear Base OM&A costs and that 90% of OPG's employees are covered by collective agreements.

OPG argued that the intervenors are in substance attempting to place OPG under a formulaic or incentive rate-making program. OPG noted that the Board rejected this concept in its *Filing Guidelines for Ontario Power Generation*,[12] which indicated that the Board will implement an incentive regulation formula when it is satisfied that the base payment amounts provide a robust starting point for that formula. OPG further argued that it was important to examine the cost drivers that underlie OM&A increases as opposed to simply discounting the average increase of 6% a year to 3% a year or establishing a formulaic 6% increase over the entire period.

OPG claimed that the funding levels proposed by the intervenors will deny OPG the funds necessary to reduce maintenance backlogs, improve preventative maintenance, and outage planning. It would also compromise OPG's ability to comply with the Province's directions regarding refurbishment and new nuclear build. OPG stated that almost $189 million of the Base OM&A increase from 2005 to the 2009 period was due to nuclear new build and Pickering B refurbishment. Both were undertaken at the direction of the Province.

Increased labour costs

Intervenors also expressed concern about the increase in labour costs over the period 2005 to 2009. SEC pointed out that labour costs, as demonstrated in reports prepared by Mercer Human Resources Consulting (Mercer) and Towers Perrin, are well above market levels. SEC also questioned the rationale for a license retention bonus that is paid to nuclear operators, and the richness of other post employment benefits (OPEBs).

The Vulnerable Energy Consumers Coalition (VECC) argued that as the 6.5% increase in compensation from 2007 to 2008 per nuclear FTE (excluding OPEB costs) was not satisfactorily explained by OPG, the increase should be limited to 4%, which would reduce total 2008 compensation costs by $20.6 million.

Both the Association of Major Power Consumers in Ontario (AMPCO) and SEC questioned the OPG Incentive Pay Program given OPG's poor economic performance. They noted that performance payouts increased from $24.6 million in 2005 to $29 million in 2007 while nuclear production productivity declined and operating costs per unit increased by 19%. AMPCO recommended that OPG introduce a more meaningful incentive pay plan at its next rates case. OPG responded that these arguments rely on

[12] Ontario Energy Board, *Filing Guidelines for Ontario Power Generation: Setting Payment Amounts for Prescribed Generation Assets*, EB-2006-0064, July 27, 2007.

a selective use of evidence and demonstrate a lack of understanding of its Incentive Pay Program; that its staffing levels increased due to initiatives by nuclear regulators and changing demographics; and that any labour costs must consider annual wage scale movements.

OPG stated that any organization with a heavily unionized workforce must balance its business requirements with the long-term interest in working with a union. OPG submitted that the Board's review of OPG's management decisions regarding labour negotiations must consider the consequences of potential labour disruptions.

The Power Workers Union (PWU) supported OPG's proposed OM&A expenditures as costs necessary for the reliable and safe operation of OPG's prescribed nuclear assets. PWU submitted that any analysis of labour cost trends should exclude components that are subject to significant variance such as pension and OPEB costs. PWU argued that the average annual increase of 4% is reasonable and consistent with the 3% to 4% increase in OPG's standard labour rate. PWU further submitted that the labour costs of Bruce Power L.P., the operator of the Bruce nuclear stations, are the proper comparator for OPG's labour costs. PWU submitted that such a comparison revealed OPG's 2006 wages (for PWU staff) were, on average, 12.8% lower than Bruce Power's costs.

<u>Productivity and benchmarking</u>
The third area of concern raised by many intervenors was OPG's benchmarked performance.

A number of benchmarking analyses and cost studies were examined in this proceeding. These included:

- the Electricity Utility Cost Group (EUCG) cost performance data base,
- the World Association of Nuclear Operators (WANO) database,
- the Navigant Staffing Benchmarking Analysis (Navigant Report), and
- salary surveys prepared by Towers Perrin, Mercer Human Resources Consulting, and Watson Wyatt.

EUCG is a voluntary association of nuclear generators, including most American nuclear generators, as well as non-North American ones. EUCG collects, validates and publishes cost and production data.

The WANO data base provides non-cost performance data, including a unit capability factor and nuclear index performance. The unit capability factor is a WANO standard while the nuclear performance index is a weighted average of ten WANO indicators.

The Navigant Report was commissioned by OPG in 2006. The primary objective of the study was to develop staffing benchmarks for OPG nuclear operations. Benchmarks were based on data from the four Canadian CANDU plants not operated by OPG (Bruce A, Bruce B, Pt. Lepreau in New Brunswick, and Gentilly-2 in Quebec).

Towers Perrin, Mercer and Watson Wyatt conduct yearly surveys of their clients to determine overall salary increases. OPG engaged Mercer to conduct a market benchmarking review comparing actual salary band compensation levels. OPG also participated in a study of the Power Services Industry conducted by Towers Perrin. The study compares salary levels by position where job matches are sufficiently close.

A number of parties referred to the MOA between the Province of Ontario and OPG which sets out the Province's expectations regarding benchmarking and operational performance:

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.[13]

SEC, AMPCO and the Canadian Manufacturers & Exporters (CME) noted that over the 2005 to 2007 period, OPG's productivity declined and production did not match, let alone exceed, the increase in costs. The intervenors questioned OPG's commitment to benchmarking.

Board Staff submitted benchmarking evidence indicating that OPG's operating costs substantially exceed others in the industry.

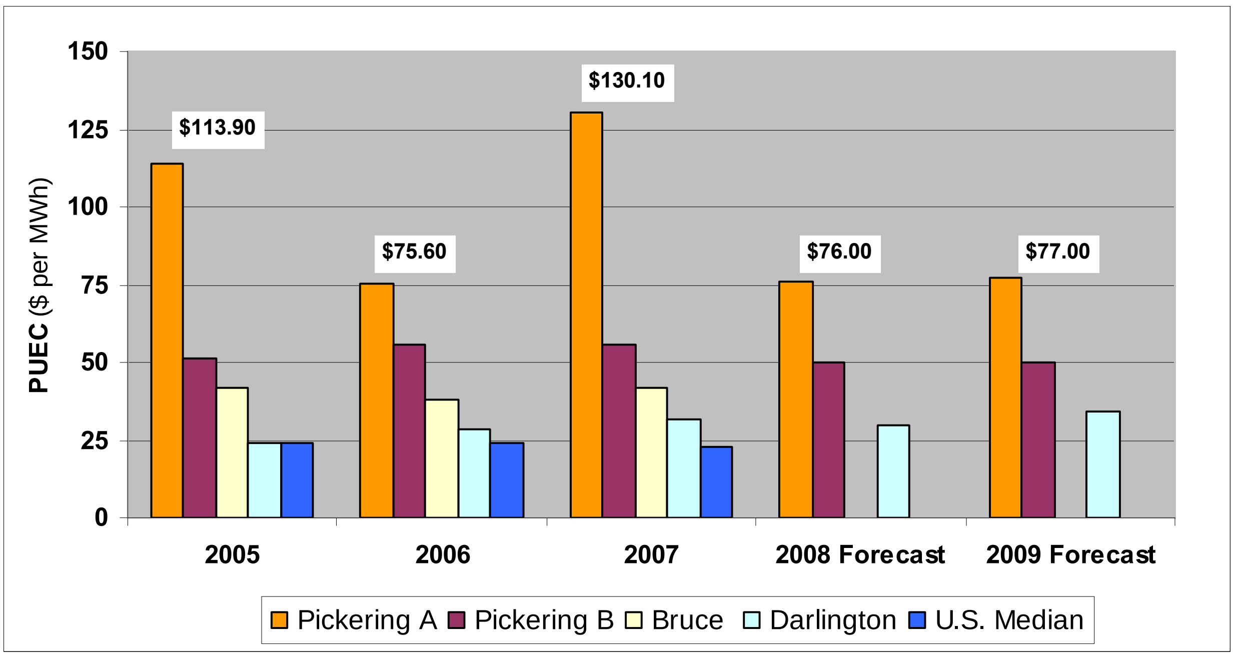
Chart 2-1 shows the differences in the production unit energy cost (PUEC) in the period from 2005 to 2007 along with OPG's forecasts for 2008 and 2009. PUEC is calculated by dividing a plant's OM&A and fuel costs by the amount of energy produced in a

[13] Memorandum of Agreement, paragraph A.3.

period. The per MWh amounts shown on the face of the chart are for the Pickering A station, which has the highest PUEC of the stations shown on the chart.

Chart 2-1 shows that the production cost per MWh for Pickering A and Pickering B have been substantially greater than for Bruce Power. Over the three years 2005 to 2007, Pickering A's unit production cost was on average three times higher than Bruce Power and four times the U.S. median. Darlington's performance is better than Bruce Power, but is worse than the U.S. median. The average cost per MWh at Pickering A over the three-year period was $107 compared to $24 for the U.S. median and $41 for Bruce Power.

Chart 2-1: Comparative Nuclear PUEC Costs



Sources: Ex. J5.4; Ex. L-4-2, Attachment 3, pp. 18, 21, and 24.

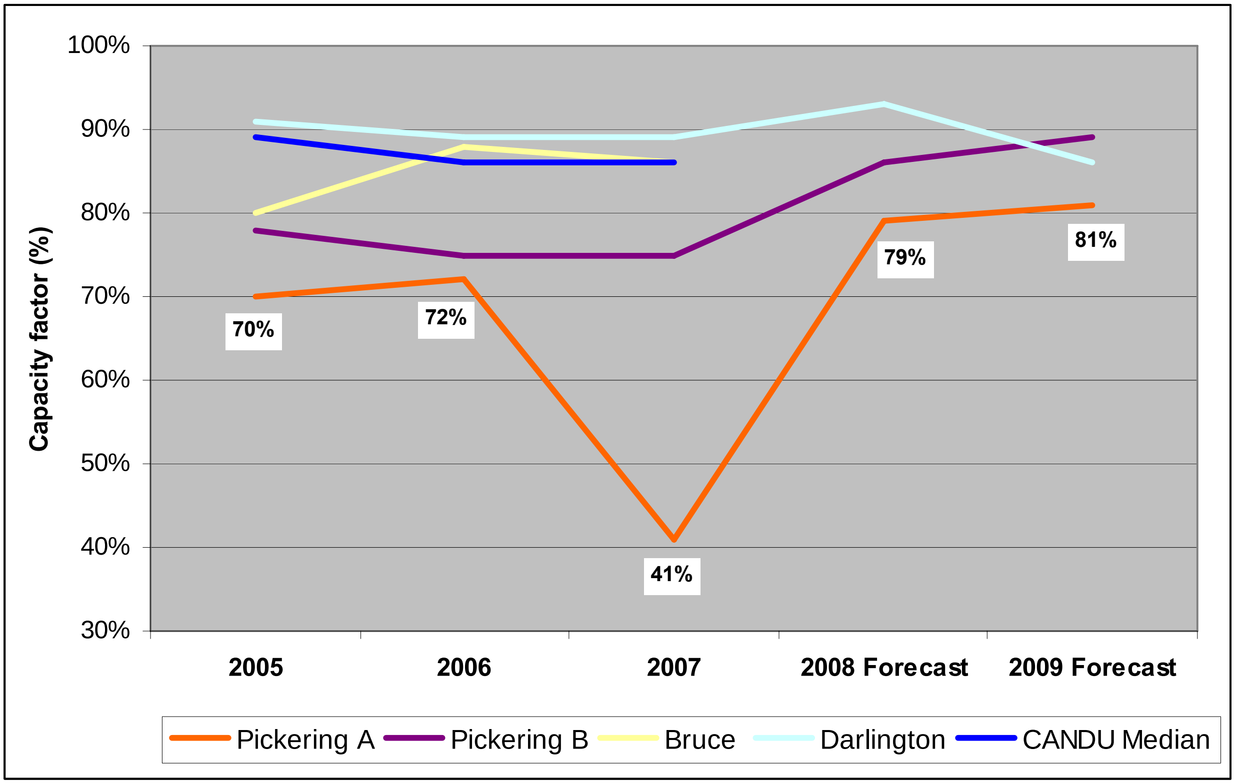
Many intervenors were critical of both the results of OPG's benchmarking and what they viewed as the apparent reluctance to engage in benchmarking. AMPCO submitted that Pickering A is almost five times more costly than the top quartile of U.S. operations, while Pickering B is two and a half times more costly.

The PUEC of a generating plant is a function of both the level of costs incurred and the plant's capacity factor. Even a very low-cost facility can have a high PUEC if the plant has an extended outage in a period.

Chart 2-2 shows the capacity factors for the OPG-operated plants compared to the capacity factors of Bruce Power and the Canadian CANDU median. The capacity factors shown on the face of the chart are for the Pickering A station, which had the lowest capacity factor of the plants included in the chart.

OPG stated that in the first quarter of 2008, the capacity factors achieved at its nuclear stations were: Darlington – 99%; Pickering A – 79%; and Pickering B – 86%.

Chart 2-2: OPG's Nuclear Capacity Factors Compared to Bruce and Canadian CANDU Median



Source: Ex. J5.4, Ex. L-4-2, Attachment 3

Darlington's performance over the three-year period 2005 to 2007 was similar to that of Bruce Power and the Canadian CANDU median; however, Pickering A and Pickering B operated at lower capacity factors, especially in 2007. Over the three-year period 2005 to 2007, the average capacity factor at Pickering A was 61% compared to 85% at Bruce Power and 87% for the CANDU median.

A number of parties questioned the long-term viability of the Pickering plants, particularly Pickering A. Energy Probe noted that the operating costs of Pickering A exceeded the value of the electricity generated and asked the Board to withhold payments for any facility that raises the cost of power for consumers.

AMPCO argued that over the 2005 to 2007 period, the average cost of Pickering A power was double the Hourly Ontario Energy Price and the nuclear payment amount received by OPG under O. Reg. 53/05. AMPCO concluded that even with the forecasted cost of 8.1 cent/kWh (AMPCO's calculation) in the test period, the prudence of continued operation of Pickering A remains a concern. AMPCO argued that OPG should be required to file a long-term assessment of the viability of Pickering A in the next rates application. SEC also argued that OPG should be directed to file a plan which demonstrates that Pickering A and Pickering B can operate at costs similar to other generators.

OPG responded that the Board's role in this application is to review the costs of Pickering A, and based on these costs, set reasonable payment amounts. OPG argued that the Board should not, and cannot, decide the ultimate viability of Pickering A, as this is beyond the scope of Section 78.1 of the *OEB Act*.

Regarding the AMPCO and SEC submissions that OPG's costs are excessive given the benchmarking results, OPG responded that the intervenors used selective data and disregarded technical differences regarding Pickering A and Pickering B. OPG also argued that AMPCO's assertion that OPG was resistant to benchmarking was unsupported. OPG maintained that it is committed to benchmarking and is in full compliance with the requirements in the MOA.

OPG also noted that it expects Pickering A and B's performance to improve substantially in the future and submitted that Darlington will continue to perform as well as it has in the past. Most of the intervenors countered that the forecasted results for 2008 and 2009 are unduly optimistic and the Board should discount these projections.

OPG also questioned the arguments by a number of intervenors that the Navigant Study supports the conclusion that 2006 staffing levels were 12% higher than benchmark. OPG claimed that the Navigant Study cannot be used to test the level and reasonableness of OPG's labour cost because the Navigant Study is not representative of staffing levels in the test period.

Regarding the suggestion that the OM&A budget should be treated on an envelope basis, OPG responded that while it should be free to manage specific expenditures within an OM&A envelope, it is opposed any determination of the OM&A costs through a benchmarking exercise.

Board Findings

This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. The second is the extent to which the Board should use the detailed benchmarking evidence to assess the reasonableness of the costs OPG seeks to recover.

With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts.

As discussed in Chapter 9 of this decision, the Board has rejected OPG's proposed payment structure for the nuclear plants (which was to include a fixed amount of $1.2 billion during the test period plus a per MWh payment amount to cover the balance of the revenue requirement). Instead, the Board has decided to retain the current variable payment structure of an amount per MWh regardless of the level of production. If OPG operates its plants at a unit cost higher than the approved payment amount, the excess costs will be borne by OPG and its shareholder. Consumers will not be at risk for costs in excess of the costs used to set the payment amount. Therefore, the Board does not accept the suggestion of intervenors that it order OPG to file a study on the long-term viability of Pickering. The long-term viability of the Pickering stations is an assessment more properly made by the shareholder knowing that the Board will only allow the recovery of reasonable costs and that the payment structure will be such that consumers will not bear production risk.

The benchmarking issue is more important. The direction given by the Province to OPG in the MOA is very specific. OPG is directed to seek "continuous improvement in its nuclear generation business." To this end, the MOA states: "OPG will benchmark its performance in these areas against CANDU Nuclear plants worldwide as well as against the top quarter of private and publicly owned nuclear electricity generators in North America." And finally, the MOA states: "OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board in this proceeding is faced with the task of determining whether the costs OPG seeks to recover are reasonable. A very important tool available to the Board is the benchmarking analysis.

Very little benchmarking evidence was filed by OPG in its initial application. This evidence was largely produced during cross-examination when OPG filed the Navigant Study.

The most common measure of productivity in nuclear generation industry is PUEC. The PUECs of the two Pickering stations are far above industry averages as Chart 2-1 indicates; in fact, the operating cost performance of Pickering A may be the worst of any nuclear station in North America. In 2006, Pickering A had a PUEC three times the U.S. average ($75.60 per MWh compared to $24.00 for the U.S. Median) and twice the Bruce unit cost of $38.00 per MWh; in 2007 Pickering A had increased to $130.00 per MWh compared to $23.00 for the U.S. median and $42.00 at Bruce.

Pickering B's 2006 PUEC was better at $55.00 per MWh but was still more than twice the U.S. median and significantly above Bruce. In 2007, Pickering B remained relatively constant at $56.00 per MWh, which was still more than twice the U.S. median and 30% greater than Bruce. The Darlington plant demonstrates a more respectable performance at $29.00 per MWh in 2006 and $32.00 per MWh in 2007.

The unit costs at Pickering A and Pickering B are forecast to improve in 2008 due to higher planned capacity factors. OPG claimed that the Pickering A operating costs will decline from $130.10 per MWh in 2007 to $76.00 in 2008 and $77.00 in 2009. Similarly, OPG claimed that the Pickering B costs will decline from $56.00 in 2007 to $50.00 in both 2008 and 2009. A number of intervenors were skeptical of these promised results.

OPG made two arguments concerning the PUEC benchmarking data. The first argument made by OPG was that the productivity results flow from technology decisions made in the past that should not be questioned using hindsight. In other words, the Board must assume that the technology decisions were prudent at the time they were made and the poor productivity results evident today, while unfortunate, are consequences of those decisions to be borne by the Ontario consumer. The Board finds this an unsatisfactory response.

OPG's primary argument was that the benchmarking data is unreliable.

The Board does not believe it is sufficient for OPG to simply discount the benchmarking studies on the basis of data quality. The studies are all based on standard measures used by the nuclear industry throughout the United States and Canada. While caution should be exercised when reviewing such data, the Board is satisfied that the studies provide meaningful insights into OPG's operations. Moreover, even if there are frailties in the data, the differentials remain striking, particularly with respect to Pickering A. The reason why the MOA emphasized benchmarking was because such studies can and do shine a light on inefficiencies and lack of productivity improvement.

While OPG criticizes the data, the Board notes that few steps have been taken to improve the quality of studies. The Board also notes that benchmarking studies were not filed as a matter of course but rather were reluctantly produced during the course of cross-examination.

Moreover, the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. The Navigant Study was delivered two years ago on September 15, 2006. There appear to be no benchmarking studies underway. And OPG has not decided what benchmarking evidence, if any, it will present at the next rates case.

Navigant completed Phase I of its study in 2006. Phase 2 as described at page 9 of the Navigant Report was to set OPG's strategy and performance targets. Specifically, Phase 2 was to address the question "what level of cost and operational performance improvement is justified". Phase 3 was to develop and execute an implementation plan. Specifically, Phase 3 was to address the questions "what specific initiatives and actions are needed to achieve identified performance improvement targets".

The questions Navigant suggested should be addressed in the second and third phases of the study are important questions. They are directly responsive to paragraph A.3 of the MOA.[14]

[14] "OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.

The production costs of the Pickering A station are a particular concern. In the past, a major reason for the high PUEC for Pickering A has been the extent of unplanned outages and the resulting low capacity utilization. OPG has forecast significantly higher capacity factors for Pickering A in 2008 and 2009. But, as Chart 2-1 illustrates, even at those higher production levels, the PUEC for Pickering will still remain well above the PUEC for Pickering B, will be significantly higher than the PUEC of the Darlington station, and will stay well above the PUEC achieved by the Bruce station over the period 2005 to 2007. Thus, poor capacity factors are not the whole reason for a high PUEC at Pickering A.

The Board estimated the PUEC for Pickering A assuming it were able to reach the forecast capacity factors of the Pickering B station in 2008 and 2009. Even if Pickering A were able to increase its planned capacity factors by that much (from 79% in 2008 and 81% in 2009 to 86% in both years), the Board estimates that the PUEC of Pickering A would only fall to around $70 per MWh, a level that is still much higher than the next highest cost station in Chart 2-1. In the Board's view, this indicates an issue with the overall level of production costs at Pickering A.

Under these circumstances, the Board believes that a reasonable action is to disallow 10% of the Base OM&A costs of Pickering A. This represents a test period disallowance of $14.9 million in 2008 and $20.1 million in 2009. Even with those amounts removed from the revenue requirement, the amount of the operating costs of Pickering A will still remain well above those of other nuclear plants.

The Board will have an opportunity to reexamine this issue when the benchmarking studies are updated in the next proceeding. At that time the Board will examine any improvement or deterioration in production unit energy costs compared to other utilities, and the reasons for those changes.

Aside from this adjustment, the Board will allow the OM&A forecast by OPG. The Board understands the concern of the intervenors regarding the level of costs, but believes it is important to examine underlying cost drivers. A number of the planned expenditures are related to safety and cost improvements. The Board's main concern is that there be a significant improvement in operating costs. As the MOA stated, "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." The Board recognizes that new investments will be necessary to reduce these costs.

2.3 Nuclear Advertising

OPG included in its revenue requirement for the test period $3 million for membership in the Canadian Nuclear Association (CNA). Of this amount, $2.3 million is for OPG's contribution to CNA's advertising program. OPG forecast an additional expenditure of $3.7 million on advertising in support of nuclear generation. In total, $6 million is forecast to be spend on advertising related to nuclear generation.

The OPG position was that this advertising is designed to create public support for nuclear generation and communicate to the public that nuclear generation is safe and environmentally friendly. SEC claimed this was not the purpose of the advertising. Rather SEC claimed it was an attempt to influence public opinion on the future of Ontario's supply mix. SEC asked the Board to disallow all the advertising expense.

Energy Probe also submitted that customers should not pay for nuclear advertising intended to influence public opinion or public policy. It cited numerous examples where U.S. regulators disallowed such expenditures and concluded that the entire nuclear advertising expenditure of $6.7 million should be disallowed.

OPG responded that its nuclear advertising activities have nothing to do with the future power supply but are designed to inform Ontario residents about nuclear safety and environmental benefits. OPG stated that Energy Probe's arguments were questionable characterizations of statements by OPG's witnesses and should not be treated as evidence. In addition, OPG noted that Energy Probe failed to acknowledge that some of the U.S. rules cited allowed for exemptions.

OPG also disputed that nuclear advertising can influence the outcome of the IPSP proceeding noting that the Province has already decided the future course for nuclear generation in Ontario. OPG claimed that a full discussion of nuclear energy, by both proponents and opponents, is in the public interest and OPG's communication is an essential part of that discussion.

Board Findings

The Board is of the view that the advertising program is largely directed to convincing the public of the advantages of new nuclear facilities and has little to do with established nuclear facilities or prescribed assets.

The Board finds that $2.3 million of the $6.0 million that the OPG forecast for nuclear advertising is related to development of new nuclear facilities and will therefore be disallowed as it is not related to the prescribed assets.

2.4 Nuclear Fuel

OPG forecast nuclear fuel costs of $162.4 million for 2008 and $204.2 million for 2009. Actual fuel expenses were $105 million in 2005, $104.9 million in 2006 and $113.0 million in 2007.

Compared to 2007, the 2008 fuel costs represent an increase of 47% and the 2009 forecast costs represent an increase of 81%.

OPG stated that the nuclear fuel cost forecast is based on the best information available at the time the forecast is prepared. Up to mid-2007, the spot price of uranium increased significantly over historical levels. OPG said that it attempts to manage price volatility by using a mix of both market and fixed-price contracts. OPG argued that this blended supply will ensure that any price increases are mitigated.

No intervenor objected to the OPG nuclear fuel cost forecast. Board staff noted that since OPG filed its application in late 2007, the market price of uranium has fallen sharply. OPG proposed the establishment of a nuclear fuel variance account to capture differences between forecast and actual nuclear fuel expense.

Board Findings

The Board accepts that uranium costs and fuel prices are highly volatile and OPG has developed a reasonable strategy to manage this risk through a supply portfolio consisting of both market and fixed-price contracts. The Board accepts the forecast nuclear expense. The Board has also determined that the proposed variance account should be established. This is discussed further in Chapter 7.

2.5 Capital Expenditures

Table 2-4 sets out actual and forecast nuclear capital spending. OPG proposed capital expenditures of $189 million in 2008 and $330 million in 2009. The 2009 forecast amount includes $148.8 million in possible capital spending on Pickering B refurbishment, a project that has not yet been approved by OPG's Board of Directors. Recovery of refurbishment costs is covered by specific requirements of O. Reg. 53/05. For that reason, the Board deals with the possible refurbishment costs separately in section 2.6 of this decision.

Table 2-4: Nuclear Capital Expenditures (excluding refurbishment capex)

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast
Nuclear capital expenditures	**$ 138.9**	**$ 152.2**	**$ 195.7**	**$ 189.0**	**$ 182.0**

Source: Ex: D 2-1-1

The capital expenditure plans include $27.0 million for the P2/P3 isolation project, and released projects amounting to $83.9 million for Darlington, $30.5 for Pickering A and $21.4 million for Pickering B.

Intervenors did not object to the proposed capital budgets. The Consumers Council of Canada (CCC) recommended that the Board order an external review of OPG's capital budgeting process. Citing examples of costs over-runs and project delays, CCC concluded that the capital expenditure decisions lack "the required degree of central control and accountability" necessary for effective regulatory oversight. OPG responded that such a review would be costly and without merit given the extensive evidence regarding the existing controls in OPG's capital budgeting process.

CCC noted that OPG wrote off the book values of the non-operating Units 2 and 3 at Pickering A in 2005. OPG intends, however, to capitalize the $27 million cost of the P2/P3 isolation project as part of the book value of Units 1 and 4, which continue to operate. CCC submitted that the Board should direct OPG to provide evidence in its next application to justify the capitalization of the costs of the P2/P3 isolation project. CCC also requested that OPG provide evidence that it is unable to use the nuclear segregated funds to cover the safe storage costs for Units 2 and 3.

OPG argued that review requested by CCC is unnecessary for two reasons. First, the P2/P3 isolation project costs are a minor part of the total safe storage costs for Units 2 and 3 and relate to work that is associated with the continuing operations of Units 1 and 4. Second, OPG stated that it anticipates that the costs of safe storage can be charged to the segregated funds so the additional evidence sought by CCC is unnecessary.

Board Findings

The Board accepts forecast nuclear capital expenditures as set out in Table 2-4.

With respect to capitalization of the P2/P3 isolation project costs, the Board agrees with CCC that additional evidence and analysis of the accounting for these costs would be useful. The issue arises because OPG has shut down only two units at Pickering A, and continues to operate two others. Unless OPG intends in the future to shutdown all units at a station at the same time, the accounting for unit isolation costs is likely to recur. Thus, the Board directs OPG to provide in its next application a more detailed analysis of the nature of the costs and why accounting standards require that such costs be capitalized as part of the book values of the operating units, rather than treated as costs of shutting down units.

CCC requested that the Board direct an external review of OPG's capital budgeting process. While the Board has some concern with the process, ultimately OPG produced the business case summaries which support the proposed capital expenditures. The Board views these case summaries as an important part of the assessment of the costs and benefits of the capital expenditures, and therefore they should form part of the application. The Board directs OPG to file this analysis as part of the pre-filed evidence for its next application. This will permit a more timely and meaningful review of capital expenditures by both the Board and intervenors.

2.6 Nuclear Refurbishment and New Build

The nuclear OM&A expenses as set out in Table 2-2 of this decision contain expenses related to new nuclear generation development and the possible refurbishment of Pickering B. As noted in section 2.5 of this decision, OPG's capital expenditure forecast also included $148.8 million related to the possible refurbishment of Pickering B.

O. Reg. 53/05 contains the following specific requirements in respect of OPG's recovery of costs related to refurbishment of existing units and planning new nuclear facilities:

> **6(2)4 – Costs to increase output from or to refurbish prescribed facilities**
> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.
>
> **6(2)4.1 – New nuclear development**
> The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
>
> i. the costs were prudently incurred, and
>
> ii. the financial commitments were prudently made.

Table 2-5 shows the proposed nuclear OM&A and capital expenditures that are subject to these two sections of O. Reg. 53/05. The refurbishment of Pickering B has not yet been approved by OPG's Board of Directors. Even if it had been approved, the possible capital spending in 2009 would not be included in rate base for the test period.

Table 2-5: Proposed Nuclear Refurbishment and New Build Costs

$ millions	2008		2009	
	OM&A	**Capital**	**OM&A** [15]	**Capital**
Pickering B refurbishment	$ 6.2	-	$ 5.1	$ 148.8
Darlington refurbishment	18.5	-	22.7	-
New build	75.3	-	67.2	-
Total	**$ 100.0**	**-**	**$ 95.0**	**$ 148.8**

Source: Ex. F2-2-1, Table 1 and Ex. K6.2

OPG stated there was no need for a prudence review of the projects because all of the costs during the test period are within approved budgets.

None of the intervenors disagreed with the company. Board staff submitted, however, that as the O. Reg 53/05 refers to “incurred” costs, the regulation applies to costs which have been expended and not those which will be expended. OPG argued that Board staff’s interpretation was incorrect, noting that the plain English meaning of “incurred” is that of “takes responsibility”. Consequently, OPG argued, O. Reg. 53/05 applies to past and future costs associated with the identified projects.

SEC submitted that the $100 million of OM&A costs for 2008 and $90 million in 2009 for nuclear refurbishment and new build should be capitalized since these costs relate to future output from the nuclear plants.

OPG replied that SEC’s recommendation should be rejected because the capitalization of these costs would be inconsistent with GAAP and OPG’s established accounting policy, which does not permit capitalization of costs related to possible projects before an alternative has been selected. OPG noted that of the three alternatives under consideration (Pickering B refurbishment, Darlington refurbishment, and a new nuclear plant), none have been selected; if any of the initiatives do not proceed, capitalization would be clearly inappropriate.

Board Findings

OPG submitted that all the OM&A costs in Table 2-5 fall within approved budgets and that all relate to planning and preparation for possible refurbishments and the

[15] The $5.1 million in 2009 OM&A for the Pickering B refurbishment is included in OPG’s Project OM&A forecast found in Table 2-2.

development of new nuclear generation facilities. The Board finds that the proposed expenditures are of the type described in Sections 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and approves the inclusion of these costs in the revenue requirement.

Board staff's submission on the meaning of "incurred" in Sections 6(2)4 and 6(2)4.1 suggests that the Board need not include any forecast amounts in the revenue requirement but could permit recovery only when OPG has actually spent money on these activities. The Board agrees with the staff's interpretation and would consider delaying recovery if there was little assurance that forecast amounts would actually be spent during the test period. However, with the announcement by Infrastructure Ontario in June 2008 that OPG's Darlington property will be the site for a new nuclear plant, it is clear that OPG will incur substantial expenditures relating to the facilities during the test period. Therefore, the Board accepts inclusion in the revenue requirement of all of the OM&A amounts shown in Table 2-5.

There is no need for the Board to approve the $148.8 million in possible capital spending on Pickering B refurbishment. OPG's Board of Directors has yet to approve proceeding with refurbishment of that station. In any event, if the project is approved during the test period, the project would not be completed during the test period and the capital costs, therefore, would not enter rate base until a later period.

The Board does not agree with SEC's submission that $100 million in preliminary costs for 2008 and $90 million for 2009 should be capitalized. SEC provided no evidence that OPG's accounting policy is contrary to GAAP.

2.7 Other Revenues

Other nuclear revenues include revenues, net of associated costs, for: ancillary services; heavy water sales and processing; tritium and other radioisotope sales; and, nuclear inspection and maintenance services. OPG forecast $100.3 million of these revenues over the 21-month test period.

No intervenors disagreed with the forecast of other nuclear revenues.

Board Findings

The Board accepts OPG's forecast of other nuclear revenues.

3 HYDROELECTRIC

The regulated hydroelectric business consists of the following prescribed facilities:

- Sir Adam Beck I and II
- Sir Adam Beck Pump Generating Station
- DeCew Falls I and II
- R.H. Saunders

The Sir Adam Beck and DeCew Falls facilities are part of the Niagara Plant Group and are located in the Niagara region. R.H. Saunders is part of the St. Lawrence Plant Group, which also includes nine unregulated facilities. R.H. Saunders is located on the St. Lawrence River near Cornwall. Together, these prescribed facilities have capacity totaling 3,332 MW.

This section of the decision addresses the following issues:

- Production Forecast
- Operating Costs
- Capital Expenditures
- Other Revenues
- Design of Payment Amount

3.1 Production Forecast

The hydroelectric production forecast for the test period is 31.5 TWh. The forecast methodology incorporates a number of components:

- Water availability forecasts
- Constraints on available water at the Niagara facilities
- Capacity to pump and store water to shift production timing
- Unit efficiency levels

OPG testified that its methodology is equally likely to over-forecast production as under-forecast production and that recent forecast deviations were attributable to differences in water conditions. OPG submitted that variations in water conditions are beyond its control and difficult to forecast, and proposed that the deferral and variance account (established under O. Reg. 53/05) be continued to capture the impact of variations in natural water conditions. No intervenor took issue with the hydroelectric production forecast.

Board Findings

The Board accepts the evidence of OPG in respect of the hydroelectric production forecast and will incorporate the forecast of 31.5 TWh into the determination of the payment amount for the test period. The issue of the deferral and variance account for water conditions is addressed in Chapter 7.

3.2 Operating Costs

The hydroelectric OM&A budget includes base OM&A, project OM&A, the asset service fee and an allocation of corporate support and centrally held costs. (This last category of costs is addressed in Chapter 4.) OPG forecast the hydroelectric OM&A budget to remain stable at $119m in both 2008 and 2009.

Table 3-1: Hydroelectric Operating, Maintenance and Administrative Expenses

$ millions	2008	2009
Base OM&A		
Niagara Plant Group	41.7	43.1
Saunders GS	14.4	14.8
Total Base OM&A	56.1	57.9
Project OM&A		
Niagara Plant Group	10.8	10.3
Saunders GS	2.1	1.8
Total Project	12.9	12.1
Allocation of Corporate Costs	47.5	46.8
Asset Service Fee	2.5	2.1
Total OM&A	**119.0**	**119.0**

Source: Ex F1-1-1, Table 1; F1-2-2, Table 1; F1-3-1, Table 1

OPG explained that the 9% increase in base OM&A from 2007 to 2008 is due to the expected hiring of additional staff, the timing of projects, and a one-time credit in 2007 from Hydro One, related to earlier work. Project OM&A relates to non-recurring expenditures which do not qualify for capitalization. OPG maintained that these expenditures are subject to the same project management and oversight as capital projects.

OPG benchmarks the hydroelectric business on reliability, safety and cost. OPG pointed out that the aggregate cost of the regulated hydroelectric facilities were in the top quartile for 2005 and 2006 as shown in a report by Haddon Jackson Associates.

Hydroelectric production is also subject to a Gross Revenue Charge ("GRC"), budgeted at $228.2 million for 2008 and $244.1million for 2009. The GRC is charged to hydroelectric generators under Section 92.1 of the *Electricity Act, 1988*. The GRC consists of a property tax component based on production levels and a water rental component of 9.5% on the gross revenue calculated from the annual generation.[16] OPG explained that it does not pay the water rental component on the DeCew facilities because it does not hold a water power lease for that facility, but it does pay compensation to the St. Lawrence Seaway Management Company for conveying water through the Welland Canal.

Board staff noted that the Board has used both a line item approach and an envelope approach to assessing OM&A forecasts. Board staff noted that another approach is to use benchmarking and that the Board has used proxies and utility comparisons as a basis for determining OM&A in other situations. No other intervenor made submissions regarding the hydroelectric OM&A test period forecast.

Board Findings

The Board accepts the forecast hydroelectric OM&A for the test period. The Board notes that the benchmarking results support a conclusion that the OM&A levels for the hydroelectric business are appropriate.

3.3 Capital Expenditures

OPG is seeking approval of amounts it has spent to increase capacity, as contemplated by O. Reg. 53/05, and it is seeking approval of its forecast capital budget for the test period. Table 3-2 sets out the level of capital expenditures in the test period and shows that the Niagara Tunnel Project is by far the largest capital expenditure for this

[16] The water rental component is set at 9.5% in O. Reg. 124/02.

business. Table 3-3 shows the additions to Gross Plant in rate base over the test period.

Table 3-2: Hydroelectric Capital Expenditures

$ millions	2008	2009
Niagara Plant Group	33.6	42.2
Niagara Tunnel Project	170.6	346.8
Saunders GS	4.6	6.6
Total	**208.8**	**395.6**

Source: Ex D1-1-1, Table 1

Table 3-3: Continuity of Hydroelectric Gross Plant

$ millions	2007 Gross Plant	2008 In-service additions	2008 Gross Plant	2009 In-service additions	2009 Gross Plant
Niagara Plant Group	2,893.6	33.1	2,926.7	41.9	2,968.7
Saunders GS	1,516.5	13.1	1,529.6	6.6	1,536.2
Total	**4,410.1**	**46.2**	**4,456.3**	**48.5**	**4,504.9**

Source: Ex B2-3-1, Tables 1 and 2

Paragraph 6(2)4 of O. Reg. 53/05 states:

> 6 (2) 4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i.if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first

> order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

OPG reported two hydroelectric projects under this section of O. Reg. 53/05: the Niagara Tunnel Project and the Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project. The Niagara Tunnel Project will increase water diversion capacity at the Beck complex and is expected to increase average annual production by 1.6 TWh. The total approved budget for the project is $985 million. The capital expenditures for 2008 and 2009 are $170.6 million and $346.8 million, respectively. This project will not be completed in the test period and therefore these amounts will not be included in rate base in the test period. The Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project will convert the existing 25Hz unit to a new 60Hz unit and return G7 to service. The approved budget for the project is $32.5 million, and the capital expenditures in 2008 and 2009 are $23.4 million and $3.9 million, respectively, and are within the approved budget. This project is expected to be completed in the test period, and the amounts are included in the test period rate base.

OPG is not seeking recovery of any costs related to “financial commitments” or “pre-engineering commitment”.

With respect to the balance of the capital budget (for projects not covered by 6(2)4 of O. Reg. 53/05), OPG is seeking approval of in-service additions of $46.2 million in 2008 and $48.5 million in 2009 associated with regulated hydroelectric capital projects. OPG explained the capital budgeting process as follows:

> All regulated hydroelectric projects reflected in this category of additional capital spending are identified and prioritized using a structured portfolio approach whereby engineering reviews and periodic plant condition assessments are performed to determine the short-term and long-term expenditures required to sustain or improve assets…After a project is initiated, a rigorous project management process is in place to provide project oversight...Project closure reports are produced for all projects and post-implementation reviews are conducted for all projects over $200,000.[17]

The following table summarizes the major projects for the hydroelectric business which fall outside of Section 6(2)4 of O. Reg. 53/05. The first two projects are included in the proposed test period rate base.

[17] OPG Argument in Chief, p. 45.

Table 3-4: Major Hydroelectric Capital Projects Not subject to O. Reg. 53/05, Section 6(2)4

Project	Description	Budget ($ million)	In-Service Date
Unit G9 Upgrade Beck	Rehabilitate unit for the first time since 1974 to prevent unit failure, overcome a 10MW de-rating and provide additional generation through improved turbine runner efficiency.	$30.0	Dec. 2009
Replace HVAC System Project at R.H. Saunders	Replace HVAC to eliminate the costs of repairing this aging system, to eliminate the use of ozone-depleting refrigerants and to eliminate health risks associated with exposure to lead and asbestos.	$11.5	May 2008
Rehabilitate Canal Lining at Niagara	Investigate and repair the walls and liners of the open cut canal that services the Beck complex to restore and maintain their integrity, prevent erosion and weathering and improve water flow.	$55.0	Dec. 2011
Unit G3 Upgrade Project at Beck	Overhaul this unit to allow for reliable production in future, prevent unit failure and to achieve increased capacity through improved turbine runner efficiency.	$31.5	Jan. 2012
Dyke Foundation Grouting Project at Beck PGS	Upgrade the protective measures to prevent recurrence of the 1958 dyke failure due to sinkholes and other phenomena on the bottom of the reservoir.	$20.0	Dec. 2010

Source: OPG Argument in Chief, page 46.

Board Findings

The Board accepts that the Niagara Tunnel and Beck G7 conversion projects are projects which come within the scope of Section 6(2)4 of O. Reg. 53/05 and notes that both projects continue to be budgeted at the level originally approved by the OPG Board of Directors. The Board will accept the inclusion of the G7 project in rate base. Any variance between the OPG Board of Directors approved forecast and actual cost will be subject to review at a future proceeding. The Board notes that the Niagara Tunnel Project is subject to continued delay and concludes that the cost for this project is uncertain at this point. However, no finding related to the cost is required because it is not forecast to enter rate base in the test period. To the extent the final costs exceed the OPG Board approved level, the recovery of those incremental costs will be the subject of a future proceeding.

The Board also accepts the balance of the capital budget for 2008 and 2009 and the rate base consequences for those projects scheduled to become in-service during the test period.

3.4 Other Revenues

In the hydroelectric business, OPG earns additional revenues from the following activities:

- Ancillary Services
- Segregated Mode of Operation
- Water Transactions
- Congestion Management Settlement Credits

We will address each activity in turn.

3.4.1 Ancillary Services

Ancillary services provided by some of the hydroelectric generating facilities include the provision of black start capability, operating reserve, reactive support/voltage control service, and automatic generation control. OPG forecast ancillary service revenues of $32.4 million in 2008 and $33.1 million in 2009. These forecast revenues are used as an offset when determining the revenue requirement. OPG proposed that any variance between forecast and actual be captured in a deferral and variance account. No intervenor opposed the forecast.

Board Findings

The Board will accept the forecast for purposes of determining the revenue requirement. The Board's finding with respect to the proposed variance and deferral account is set out in Chapter 7.

3.4.2 Segregated Mode of Operation ("SMO") and Water Transactions ("WT")

OPG earns SMO revenues by segregating some of its R.H. Saunders generating units from Ontario and reconnecting them directly into Quebec. Revenues are received from Hydro Quebec. SMO net revenues have ranged between $9.9 million and $4.4 million over the last 3 years.[18] OPG submitted that forecasting revenues from SMO is difficult

[18] "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." (Ex. G1-1-1, p. 8)

because SMO is dependent upon hourly market conditions and advised that these revenues are expected to decline with the new high voltage transmission line between Ontario and Quebec. As a result, OPG did not propose to include a forecast of SMO net revenues as a revenue offset, but rather proposed to track the revenues in a variance account for later disposition. Further, OPG submitted that because it incurs costs and risks in undertaking these transactions it is necessary for it to have an incentive to undertake this activity. OPG pointed out that its trading function (which undertakes these transactions) has other commercial opportunities: "Without sufficient incentive to engage in SMO transactions, OPG will focus on these other opportunities."[19] OPG proposed that the net revenues be shared 50/50 with customers.

Water Transactions (WT) occur pursuant to agreements between the New York Power Authority and OPG to maximize energy production from the total water available for generation under international treaties. WT generally happen for maintenance, economic efficiency and climatic (ice) reasons, largely with the intention to salvage the water that forms part of an entity's generation share that would otherwise be spilled over Niagara Falls. WT net revenues have ranged between $8.4 million and $4.5 million over the last 3 years.[20] As with the SMO, OPG proposed to track WT revenues and to return 50% of the net revenues to customers through the use of a variance account. No forecast revenue would be included as a revenue offset in the determination of the revenue requirement.

Board staff questioned whether SMO revenues should in some way be incorporated into the revenue requirement and noted the approach used in the past for Union Gas Limited whereby a forecast of net revenues from transactional services is incorporated in the revenue requirement, and any incremental revenues are subject to variance account treatment and sharing. Board staff noted that under OPG's proposal, it is possible there could be a debit in the variance account if costs exceeded revenues.

CCC and AMPCO proposed alternative sharing formulas. CCC submitted that the customers should receive 75% of the net revenue, in recognition that the assets are included in rate base and in line with other similar sharing mechanisms in the gas industry. AMPCO submitted that a sharing ratio of 80/20 between customers and OPG would be appropriate, recognizing that OPG needs an incentive to undertake these

[19] OPG Argument in Chief, p. 74

[20] WT net revenues "are gross revenues less accommodation charges, and GRC." (Ex.G1/Tab1/Sch.1/p.11)

transactions, and that customers bear the costs underpinning these transactions and all costs are netted against the gross revenues before any sharing. CME supported AMPCO's submissions. VECC also questioned whether customers should receive the majority of the net revenues, given that the assets are included in rate base.

CCC also submitted that customers should not bear the costs of any uneconomic transactions. OPG did accept that customers should not be responsible for a negative balance in the account, but it was of the view that if individual transactions resulted in a net cost, those should be included in the account:

> Transactions are economic when entered into; if they become uneconomic, it is due to changing market conditions and prices. Transactions to manage excess baseload generation may result in a negative sub-account entry but have associated social and environmental benefits.[21]

SEC noted OPG's testimony that it has other incentives to enter into SMO transactions, including allowing OPG to manage excess baseload generation. SEC submitted that customers should receive 100% of the net revenues from these transactions as there is no real risk associated with the transactions and the transactions provide ancillary benefits to OPG which make them economic in any event. SEC also made an alternative proposal based on the transactional services model for gas distributors. Under SEC's alternative proposal, a forecast of SMO net revenues based on the average of the last three years' experience would be included as a revenue requirement offset and OPG would be entitled to retain a portion of any net revenues in excess of this forecast. SEC proposed that 75% of the forecast be included as an offset to the revenue requirement and that the excess be shared 75/25 between customers and OPG. SEC noted that in the case of Enbridge Gas Distribution Inc., this incentive structure worked to increase transactional revenues over a several year period.

OPG responded that changing the sharing would "disincent economic SMO transactions, as OPG's trading function will pursue other, more lucrative, opportunities."[22] OPG noted that unlike the transactional services in the gas utilities, the SMO and WT transactions are undertaken by staff which is also engaged in other transactional opportunities.

[21] OPG Reply Argument, p. 106.

[22] OPG Reply Argument, p. 104.

OPG also argued that the SMO transactions benefit consumers more generally because Hydro Quebec has significant water storage capacity and the SMO transactions tend to take place during off-peak hours, thereby facilitating greater generation at peak. Although OPG could not quantify the benefit, it claimed that to the extent there is more supply available at peak times, the market price (Hourly Ontario Energy Price, or HOEP) will decline, to the benefit of Ontario consumers.

With respect to SEC's proposed alternative, OPG responded that the use of a three year average for purposes of establishing a revenue offset is inconsistent with the evidence that these transactions are difficult to forecast and are expected to decline.

Board Findings

The Board agrees with intervenors that the analogy of transactional services in the natural gas industry is appropriate in the context of SMO and WT transactions. In both cases, the assets are part of the regulated business and customers pay all of the costs associated with operating these assets. OPG has an obligation to manage these regulated assets in an efficient manner, and if there are market opportunities available to offset costs, then the benefits of those transactions are appropriately shared with customers. It is also appropriate for OPG to have an incentive to optimize these revenues. The Board concludes that it is appropriate to incorporate a forecast of the net revenues from SMO and WT into the test period revenue requirement and to allow OPG to retain any incremental revenues during the test period. The Board concludes that this will provide a strong incentive to the company to pursue these transactions and will ensure that customers receive a benefit from the transactions as well.

The Board must establish the appropriate forecast to be included. The Board accepts OPG's position that it is difficult to forecast market driven activities, but concludes that a forecast of zero does not accord with the historical evidence. OPG has claimed that these transactions are likely to decline because of various developments. With respect to SMO transactions, the Board notes that only Phase 1 of the Ontario-Quebec interconnection is forecast to be in-service during the test period. With respect to WT, OPG's claim that WT activity will decline with completion of the Niagara Tunnel Project is not relevant since the project will not be completed during the test period.

OPG also argued that an enhanced incentive is required as these transactions compete for trading resources within OPG's unregulated trading business. However, the fact that the trading staff is also undertaking unregulated trading activities does not diminish

OPG's obligation to manage the regulated assets efficiently and for customers to share in those benefits. Incorporating a forecast into the revenue requirement determination will provide a positive incentive to pursue these transactions.

The Board concludes that an appropriate approach will be to include the average net revenues over the last three years into the forecast as a revenue offset in each year of the test period. In the case of SMO, the offset will be $6.6 million; for WT, the offset will be $6.9 million. (These amounts are for 2009; the amount for test period portion of 2008 will be 75% of that amount.) Any incremental revenues will accrue to OPG. This also simplifies the regulatory structure by eliminating the need for deferral accounts.

OPG has also argued that these transactions benefit customers generally through a beneficial impact on market prices. The Board finds that these benefits are too speculative to be taken into account in the determination of an appropriate sharing mechanism.

3.4.3 Congestion Management Settlement Credit ("CMSC") Payments

Under the IESO market rules, the IESO dispatches wholesale electricity generating facilities using its dispatch scheduling optimizer which determines process and schedules. Two schedules are run, one assuming no transmission or other constraints in the system and the other which considers known constraints, and which is actually used to dispatch. A Congestion Management Settlement Credit (CMSC) is paid to any market participant in compensation for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified). CMSC payments for OPG's regulated assets have ranged between $7.7 million and $12.6 million over the last three years.

OPG submitted that CMSC payments are different from SMO and WT revenues because "CMSC payments are not incremental revenues but rather an offset to lost production/revenue and increased costs."[23] OPG explained that most CMSC payments arise from constrained off situations that can result in wasted or inefficient use of water because dispatch is below the level of maximum efficiency. Similarly, constrained on situations can result in use of the generating units above the level of maximum efficiency or inefficient use of the Beck Pump Generation Station. OPG proposed to

[23] OPG Argument in Chief, p. 75.

retain all of the CMSC payments, arguing that to do otherwise would prevent it from recovering its losses associated with constrained off or constrained on situations. AMPCO submitted that OPG had failed to demonstrate that CMSC revenues are totally absorbed by the incremental costs and therefore recommended that the revenues be shared 50/50 net of incremental costs. Similarly, SEC submitted that OPG had provided no evidence to support its claim that the CMSC revenues equal the incremental unforecast costs. SEC submitted that these revenues should be treated as a revenue offset because the costs are likely included in OPG's forecasts.

OPG responded:

> CMSCs are intended to keep market participants whole, up to the operating profit they would have otherwise received, had they not been constrained-on or off by system conditions beyond their control.[24]

OPG quoted from an IESO presentation in support of this characterization. OPG maintained that if it is not able to retain the payments it will have no way to recoup the losses it would otherwise experience. OPG maintained that it would be too complex to quantify the incremental costs associated with constraint situations, but maintained that the payments, over a year, are a reasonable approximation of the impact on OPG's revenue. OPG noted that these payments are also subject to IESO review.

Board Findings
The Board will accept OPG's proposal. The losses which OPG incurs in constrained on and constrained off situations are mostly related to opportunity costs – the reduced production or less efficient production which results in lost revenues. The Board accepts OPG's evidence that the CMSC payments are designed to compensate for these losses – losses which are not otherwise incorporated into the revenue requirement. The Board will therefore not establish a deferral and variance account for this item.

3.5 Design of Payment Amount

Under the existing payment design, OPG receives $33/MWh for the first 1,900 MWh of output in any hour. Any production beyond the level of 1,900 MWh receives the market

[24] OPG Reply Argument, p. 107.

price. The objective of the incentive scheme is to provide OPG with an incentive to produce peaking supply in response to demand. The expectation is that this will benefit consumers by having a peaking resource available to improve system reliability and temper market prices through increased supply. OPG explained that this peaking capability is primarily available through the Beck complex, although there is also some capability at R.H. Saunders and DeCew.

OPG's evidence is that there have been situations when the current mechanism did not provide the right market signal to OPG because decision making is driven by the opportunity cost associated with the regulated price, rather than being driven by the market price in the off peak period. For this reason, OPG has proposed a new incentive mechanism. The formula for the proposed payment structure is as follows:

$$\sum_t [\text{MWavg} * \text{RegRate} + (\text{MW}(t) - \text{MWavg}) * \text{MCP}(t)]$$

Where:

MWavg = hourly volume or the actual average hourly net energy production over the month

RegRate = the regulated rate ($/MW) for the regulated hydroelectricity facilities

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

Under the proposed mechanism, for production greater than the threshold level OPG will receive the market price, and for production which is less than the hourly threshold OPG will notionally pay the market price for the production shortfall. The threshold will not be set at a fixed pre-determined level; the threshold will be the actual average hourly production during the month. OPG submitted that the incremental revenues associated with the proposed mechanism (revenues over the regulated payment level) will be significantly less than under the current scheme and that the proposed mechanism results in better operational drivers because decision making is driven by market signals and not the regulated rate. OPG concluded that the proposed mechanism is therefore preferred, but noted that under the mechanism OPG is exposed to greater financial risk because it must notionally purchase any production shortfall.

OPG estimated (using market simulation modelling) that the result of this production displacing more expensive generation would reduce the hourly market price by between $.40/MWh and $1.20/MWh, with annual estimated savings for consumers of between $80m and $270m. OPG submitted that in relation to the level of benefit to consumers, the incremental benefit to OPG (revenues in excess of the revenue requirement), which is estimated at between $5 million and $19 million, is reasonable. OPG submitted:

> The proposed mechanism provides the correct signals for peaking operations since it drives the decision to pump on the spread between forecast on-peak and off-peak prices.[25]

Most intervenors expressed dissatisfaction with the proposed mechanism although they supported the objective of the mechanism and generally agreed with OPG's evidence regarding the weaknesses of the current approach. VECC concluded that the proposal should be adopted but that its operation should be tracked in a deferral account for future disposition. Energy Probe and AMPCO each submitted that the proposed mechanism should be modified. SEC submitted that the current mechanism should be continued.

In Energy Probe's view, the proposed structure is flawed because the threshold is set at the end of the month and applied retroactively. This approach results in a perverse incentive to over-use the Sir Adam Beck Pump Generating Station ("PGS") because all pumping will lower the actual monthly average rate of generation at Sir Adam Beck thereby lowering the threshold for that month; this may happen when it is contrary to the interests of the grid and consumers. Energy Probe submitted that although OPG attempted to minimize the impact of this flaw, the scenario explored in the undertaking was simplified and unrealistic, and if the PGS were used throughout the month, the impact would be multiplied by 30. Energy Probe suggested that the unintended benefit could run to $4 million to $5 million per year.

AMPCO submitted that the treatment of PGS volumes resulted in double counting which should be corrected:

> …pumping has the effect of decreasing the average monthly volume used to set the incentive mechanism threshold. Since, *ceteris paribus*, a lower threshold translates into a higher monthly average realized price for OPG than a higher threshold, the incentive for OPG to pump at the PGS is greater than indicated by

[25] OPG Reply Argument, p. 130.

> the expected differential in market prices between peak and off-peak demand periods.[26]

OPG responded that these concerns were unfounded:

> The decision to pump is based solely on the price differential between the peak and off-peak prices at a point in time, less the associated costs. It is not based on any plan to lower the average hourly volume.[27]

OPG acknowledged that pumping will reduce the average hourly volume, but noted that the benefits to consumers from increased pumping (in terms of lower peak prices) far exceed any benefit to OPG. OPG also maintained that the concern regarding potential for gaming was baseless once elements of reality were included. For example, OPG would not be able to run the PGS continuously for physical reasons.

VECC also expressed concern that the structure of the proposal could give rise to unintended consequences including raising off-peak market prices or providing OPG a bonus even if the regulated rate exceeds the average market price for the month.

A number of intervenors took the position that the perceived flaws in the methodology could be addressed by modifying the threshold. SEC submitted that the threshold should be set exogenously:

> Because the production target that triggers the incentive is OPG's own average monthly production, OPG is being rewarded simply for exceeding its own average production on a particular day, and not for exceeding a production target that is exogenously determined to meet peak production requirements.[28]

Energy Probe proposed two alternative approaches. One would be to set the threshold externally, for example using the average hourly production for the same month in the previous three years.

OPG responded that there are two benefits to setting the threshold on the basis of actual production: it is rooted in reality and it allows for a higher volume at the regulated rate than would a predetermined volume because a predetermined volume would need

[26] AMPCO Argument, p. 49.

[27] OPG Reply Argument, p. 132.

[28] SEC Argument, p. 57.

to incorporate a risk premium. OPG submitted that setting a higher pre-determined threshold would be inappropriate because it would drive OPG to maximize production:

> The objective is not to maximize OPG's production at the regulated hydroelectric facilities but to optimize economically efficient production based on market signals, which represent the value of production at various times.[29]

Similarly, OPG opposed setting the threshold based on average historical production. OPG argued that this alternative has the same flaw as any pre-determined threshold: "it disconnects the threshold from the actual water available to the regulated facilities."[30]

Energy Probe's other alternative would be to use OPG's proposed threshold, but to net out the effect of OPG's pumping at PGS on the threshold. Similarly, AMPCO proposed that 54MWh be added to the monthly total for every 100 MWh used for pumping. (This reflects that, on average, 46 MWh is generated for every 100 MWh of energy used for pumping.) In OPG's view, adjusting the hourly volume by adding pump energy losses (AMPCO's approach) is punitive because it is higher than what OPG has actually achieved in a given month. OPG submitted that setting an unreasonably high threshold is unwarranted given the significant consumer benefits to be achieved.

AMPCO also submitted that all SMO production should be included in the calculation of the monthly average production. Energy Probe submitted that a perverse incentive may exist in relation to the SMO and urged the Board to extend its preferred solution to the SMO activities as well. OPG responded that the SMO volumes are already included in the hourly volume (the threshold) but not in the actual net energy production (the amount compared against the threshold for settlement purposes).

Board staff questioned whether an independent evaluation or regular reporting of the impact and results might be warranted. AMPCO supported Board staff's suggestion that there be an independent review of the mechanism at the next case. OPG responded that while it supported a future review of the mechanism it would not be necessary or feasible to conduct an independent review in time for the next filing. OPG proposed to file its own review of the incentive's effects on its operating decisions as part of its next application.

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[29] OPG Reply Argument, p. 131.

[30] Ibid., p. 132.

Board Findings

The Board will accept OPG's proposed incentive mechanism. The Board finds that the structure of the proposed mechanism is an improvement on the current mechanism as it leads to decision making based on the comparison of market prices, rather than on a comparison between the market price and regulated payment.

The Board also agrees with OPG that adopting a pre-determined threshold is not a preferred approach because the objective is not to maximize production but to optimize economically efficient production based on market signals. A number of the intervenors expressed concern with the potential for gaming opportunities under the new structure, particularly as a result of the threshold being determined after the fact. The Board concludes that these concerns are overstated. The opportunities to manipulate the average hourly production for the month are effectively limited by the physical operations of the PGS and by the financial risk which OPG faces related to its decision making. The Board accepts that OPG has an incentive to base pumping decisions on the forecast spread or risk being unable to recoup pumping costs. The Board would also note that if additional pumping takes place toward the end of a month, generation will necessarily take place before further pumping is possible, and this additional generation will increase production in the associated time period thereby raising the average production.

The Board will require OPG to present a review of the mechanism at the next proceeding, as it has undertaken to do. This review will examine the impact of the incentive structure on OPG's operating decisions.

4 CORPORATE COSTS

OPG's Corporate Costs include the costs of centralized support functions such as the Chief Information Office ("CIO"), Finance, Human Resources, Corporate Affairs, Energy Markets, Real Estate, Executive Office, Corporate Secretary and Law, and centrally held costs including Pension and Other Post Employment Benefits, Insurance, Performance Incentives and IESO Non-Energy Charges. OPG allocates corporate support and centrally held costs to its regulated businesses using direct assignment, when specific resources can be linked to a specific business, and any remaining costs are allocated based on cost drivers. Table 4-1 sets out the amounts allocated to the regulated hydroelectric and nuclear businesses.

Table 4-1: Summary of OPG Corporate Costs Allocated to Prescribed Facilities

$ millions	2006		2007		2008		2009	
	Hydro	Nuclear	Hydro	Nuclear	Hydro	Nuclear	Hydro	Nuclear
Support Group	19.5	210.3	21.9	236.6	28.2	263.7	28.8	262.4
Centrally Held	19.1	212.9	16.1	210.2	19.3	193.3	18.0	167.8
Total	**38.6**	**423.2**	**38.0**	**446.8**	**47.5**	**457.0**	**46.8**	**430.2**

Source: Ex. F3-1-1, Tables 2 & 3

4.1 Corporate Cost Allocation Methodology

OPG retained R.J. Rudden Associates ("Rudden") to review and provide a written report on OPG's methodology for assigning and allocating Corporate Costs, including the methodology for allocating common hydroelectric business unit costs between regulated and unregulated hydroelectric facilities. The Rudden report included a number of recommendations regarding the need for a formal quarterly review process, documentation improvements and cost driver standardization. OPG adopted the recommendations, except the recommendation to implement a standardized template to document time estimation. In OPG's view, permitting individual groups to use different formats suitable for their specific needs was an appropriate approach and meets the objective of ensuring an appropriate allocation.

OPG submitted:

> ...Rudden concluded that OPG's allocation methodology uses direct allocation where possible and appropriate allocators where direction [sic] allocation is not possible; and is consistent with best practices and applicable regulatory precedents.[31]

AMPCO and SEC expressed concern at the level of corporate costs allocated to the regulated businesses, particularly when compared to the level of costs allocated to the unregulated businesses. AMPCO noted that the increases between 2005 and 2007 for the nuclear and regulated hydroelectric costs were 25% and 38% respectively, while the increase for the unregulated costs was 6.5%.

OPG maintained that it has fully explained the growth in these costs. Whereas the intervenors have compared costs between 2005 and 2007, OPG argued that a better comparison would be between 2005 and 2009, to include the test period. Costs allocated to unregulated operations increase by 17% in that period; total corporate costs increase by 22%; and costs allocated to nuclear increase by 21%. Costs allocated to hydroelectric increase by a greater amount, 69%, because of the high levels of capital spending in the regulated hydroelectric business, especially relative to the capital spending in the unregulated business. OPG also noted that the overall level of costs allocated to regulated operations, as a percentage of total corporate costs, has ranged between 68% and 71% over the period and is under 70% for the test period.

CME argued that the allowance for the corporate cost allocation should be limited to the 2006 level and that the revenue requirement for the test period should be reduced by $40 million as a result:

> We submit that the Rudden Study on which OPG relies only operates to establish the reasonableness of OPG's 2006 allocation of corporate costs. Since there is no independent evidence to justify the increase in the allocations of corporate costs which OPG seeks to recover in its test year revenue requirement, the allocated amounts should remain at their 2006 level.[32]

OPG responded that Rudden used 2006 data because that was the most recent data available when the application was filed in November 2007. OPG's testimony is that the

[31] OPG Argument in Chief, p. 83.

[32] CME Argument, p. 62.

methodology has been applied consistently for 2008 and 2009 forecast costs, and that the auditors have confirmed its application to 2007 costs.
AMPCO submitted that a more comprehensive cost allocation methodology should be in place to ensure there is no cross-subsidization of the unregulated business:

> AMPCO recommends that the Board establish for OPG mandatory requirements based upon principles that reflect the policies underlying the recently amended Affiliate Relationship Code for Electricity Transmitters and Distributors. Specifically OPG should be required to satisfy the same principles with respect to Transfer Pricing, restrictions on sharing of Confidential Information, and similar reporting protocols to the Chief Compliance Officer so that transparency can be achieved to ensure that ratepayers are not subsidizing OPG's unregulated business.[33]

OPG responded that an affiliate relationship type code would impose costs without additional benefits. OPG noted that it is a single company without affiliates, and argued that it has developed a fair and reasonable methodology for allocating common corporate costs which is consistent with the ARC provisions and has been independently reviewed.

A number of intervenors proposed further independent evaluation of the corporate cost allocation. Board staff suggested there should be an external review of the corporate costs allocated to the prescribed assets, noting the Board's decision in Enbridge Gas Distribution's 2006 rates proceeding which required an independent review of these costs. VECC also submitted that an external evaluation was warranted given the significant increase in costs allocated to the regulated operations. While CCC recognized the Rudden report as an important first step, it submitted that the Board should direct OPG to undertake an independent study of internal corporate processes to ensure that services are not duplicated and the processes for review, reporting and approval are effective.

OPG responded that it will submit an independent evaluation of its corporate cost allocation methodology, and its use of the methodology in the test period, as part of the next application. OPG submitted, however, that an independent review of its corporate processes was not warranted and cited various internal activities it undertakes to ensure these costs are reasonable.

[33] AMPCO Argument, p. 36.

CCC also recommended that OPG should continue benchmarking all corporate support and administrative departments. CCC submitted that intervenors should have a role in establishing the terms of this benchmarking. CCC suggested this approach could reduce regulatory time and expense. OPG responded that it intends to continue benchmarking CIO, Finance and Human Resources. However, OPG submitted that it would be inappropriate for the Board to direct that intervenors be involved in establishing the terms of benchmarking. In OPG's view, this is appropriately the responsibility of OPG. OPG noted that the example of the Enbridge CIS intervenor involvement followed from a decision in which the Board rejected a proposed 12-year contract and cited deficiencies in the company's evidence; in OPG's view no comparable circumstance is present in this application which would warrant intervenor involvement.

Board Findings

The Board will accept the allocation of corporate costs for the test period. The percentage increase in costs allocated to the nuclear business between 2005 and 2009 is comparable to the overall increase in corporate costs during that period. The increase in costs allocated to the hydroelectric business is much larger in percentage terms than the overall increase, but the Board accepts that this increase is related to the relative size of the Niagara Tunnel Project and its impact on the resulting allocations. The Board notes that the allocation of total costs to the regulated businesses (in percentage terms) is in line with historical levels. Intervenors have criticized the Rudden report on the basis that it used 2006 data. The Board finds that using 2006 data was acceptable in the circumstances, given the timing of the report and the availability of actual data.

AMPCO has recommended that OPG be subject to requirements similar to the *Affiliate Relationships Code for Electricity Distributors and Transmitters*. The Board concludes that such an approach is not necessary at this time because the provisions of the Code related to shared corporate services (namely, pricing based on fully allocated costs) are essentially the same as the approach adopted by OPG for the allocation of corporate costs. An appropriate cost allocation methodology and independent review can ensure there is no cross-subsidy between OPG's regulated and unregulated businesses. The Board notes that OPG has undertaken to present another independent evaluation of the corporate cost allocation as part of its next application. The Board accepts this undertaking and will direct OPG to file such a study.

The Board expects the next independent review to include an evaluation of the cost allocation methodology and consideration of the Board's "3-prong test". This test was addressed in the Board's decision for Enbridge Gas Distribution 2006 rates.[34] That decision stated:

> The 3-prong test was defined in the Board's Decision in EBRO 493/494 and can be summarized as follows:
>
> > Cost incurrence: Were the corporate centre charges prudently incurred by, or on behalf of, the companies for the provision of services required by Ontario ratepayers?
> >
> > Cost allocation: Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?
> >
> > Cost/Benefit: Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?
>
> The costs must pass all three tests. If a service, or the scope of service, is not needed by the gas distribution utility, then the cost should not be recovered from ratepayers. This is so even if the benefits may exceed the costs in question.[35]

The Board encourages OPG to continue with its benchmarking activities in the corporate areas it has identified. While it is often advisable to consult with intervenors where practicable in these activities, the Board will not require OPG to involve intervenors in these activities at this time.

4.2 Corporate Costs – Regulatory Affairs

CCC submitted that OPG's regulatory affairs budget for 2009 should be reduced by 50% because the 2008 budget, which included preparation of studies to support the application, is not an appropriate baseline for the 2009 budget. CCC stated that a variance account could be established to capture deviations from budget. SEC noted the 85% increase in the Corporate Affairs budget between 2006 and 2008, and submitted that costs for consultants and purchased services for regulatory affairs should be subject to deferral account treatment because many of these fees are beyond OPG's control and the timing of the next rate proceeding is uncertain.

[34] EB-2005-0001/EB-2005-0437, *Decision with Reasons*, February 9, 2006.

[35] Ibid., pp. 79-80.

OPG responded that it will be filing a new application in 2009 and therefore the regulatory affairs budget is not excessive. OPG submitted that a deferral account is not required because it would not meet a materiality threshold in the context of OPG's operating costs.

Board Findings

The Board will not make any adjustments to the regulatory affairs budget. It is clear that OPG will be filing another application shortly after this decision is issued. Therefore, the regulatory affairs costs for 2009 are likely to be of the same magnitude as the budget for 2008. The Board agrees with OPG that a deferral account is not necessary for regulatory costs. In the context of OPG's overall situation, these costs are not material.

5 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

OPG's balance sheet includes substantial liabilities for nuclear used fuel management, nuclear decommissioning, and low- and intermediate-level waste management. At December 31, 2007, those liabilities totalled almost $10.8 billion. They are projected to grow to $11.7 billion by the end of 2009.

The regulatory treatment of these liabilities was a major issue in this proceeding. The nuclear liabilities are relevant to the determination of: the amount of costs with respect to the Bruce nuclear generating stations (Chapter 6); the balance in the nuclear liability transitional deferral account (this chapter and Chapter 7); and, rate base and cost of capital (Chapter 8).

This chapter first provides some factual information and background on OPG's obligations for waste management and decommissioning at each of its nuclear facilities, the arrangements in place to fund those liabilities, and how the company presents them in its consolidated financial statements. It then summarizes OPG's proposed treatment of nuclear liabilities in the calculation of the revenue requirement, the balance in the Section 5.1 deferral account, and the calculation of Bruce costs. The balance of the chapter deals with OPG's rationale for its proposal, the submissions of the other parties, and the Board's findings.

5.1 Background

5.1.1 Nuclear liabilities

OPG is legally responsible for the ongoing, long-term management of radioactive waste from each of its nuclear facilities – Pickering A, Pickering B, Darlington, Bruce A, and Bruce B. OPG is also responsible for decommissioning the nuclear plants after the plants are shut down permanently. The Bruce A and Bruce B stations are not prescribed facilities. They are owned by OPG but have been leased to, and are operated by, Bruce Power L.P.

The amounts of OPG's nuclear waste management and decommissioning liabilities (collectively the "nuclear liabilities") are based on the costs OPG expects to incur up to and beyond the termination of operations and the closure of nuclear facilities. Costs will be incurred to dismantle, demolish and dispose of facilities and equipment, to remediate and restore the plant sites, and to manage nuclear used fuel and low- and intermediate-level waste material.

OPG estimated that the undiscounted amount of future cash outflows for waste management and station decommissioning at the end of 2007 was $24 billion (measured in 2007 dollars). The amounts and timing of future cash outflows are based on significant assumptions and are necessarily subject to considerable uncertainty. OPG's current nuclear waste management and decommissioning plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown, and to 2065 for placement of used fuel into a long-term depository followed by extended monitoring.

OPG measures the nuclear liabilities by discounting the estimated cash flows for the time value of money. When OPG acquired the generation business of Ontario Hydro on April 1, 1999 and commenced operations, the nuclear liabilities were less than $6.5 billion, which equalled the expected future cash outflows discounted at 5.75%.[36] By the end of 2007, the liabilities had grown to $10.8 billion. The principal reasons for the increase since 1999 are accretion expense (as time passes, the present value of estimated cash outflows increases) and a material upward revision to estimated future cash flows that was recognized at the end of 2006.

Table 5-1 is a continuity schedule of nuclear liabilities from the beginning of 2005 to the end of 2009. For liabilities established before the end of 2006, the discount rate is 5.75%. For liabilities recorded on December 31, 2006, the discount rate is 4.6%, which was based on bond market conditions at that time.

[36] OPG 1999 consolidated financial statements, Note 7.

Table 5-1: OPG's Actual and Forecast Nuclear Liabilities

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast
Opening balance	$ 8,150	$ 8,567	$ 10,328	$ 10,781	$ 11,207
Accretion	467	490	575	603	626
Accrue variable expense	34	38	76	48	39
Liabilities settled	(84)	(153)	(198)	(225)	(193)
Change in cost estimates	-	1,386	-	-	-
Ending balance	**$ 8,567**	**$ 10,328**	**$ 10,781**	**$ 11,207**	**$ 11,679**
By facility:					
Pickering/Darlington	$ 5,009	$ 5,714	$ 5,921	$ 6,182	$ 6,466
Bruce	3,558	4,614	4,860	5,025	5,213

Source : Exhibit J1.5.

At December 31, 2007, total nuclear liabilities of $10,781 million were comprised of a liability for used fuel management of $5,938 million and a liability for nuclear decommissioning and low- and intermediate level waste management of $4,843 million. OPG advised that its nuclear liabilities are substantially higher than the liabilities of nuclear operators in the United States, which do not directly bear the risk of managing nuclear fuel waste. In the U.S., the federal government bears the liability for managing used fuel and collects a per kWh charge from operators.

5.1.2 Funding

At the end of 1999, the year that OPG assumed the nuclear waste management and decommissioning obligations from Ontario Hydro, the nuclear liabilities were largely unfunded. There was only $367 million segregated to satisfy the liabilities compared to total nuclear liabilities of $6,591 million.[37]

In 2002, OPG and the Province of Ontario finalized the Ontario Nuclear Funds Agreement (ONFA). That agreement established two segregated funds – a used fuel fund and a decommissioning fund – to be held by an independent custodian. The used fuel fund will be used to fund future costs of long-term nuclear used fuel waste management. The decommissioning fund will be used to pay for the cost of

[37] OPG 1999 consolidated financial statements, Note 7.

decommissioning the plants and the cost of managing low- and intermediate-level waste.

The ONFA requires OPG to make quarterly payments to the funds. OPG's payments are determined by a Provincially-approved reference plan (Approved Reference Plan) that sets out the estimated costs to meet OPG's nuclear waste management and decommissioning obligations. The ONFA requires OPG to prepare reference plans when required by law or regulatory bodies, or every five years, whichever is earlier. The current Approved Reference Plan was approved by the Province in December 2006. The ONFA also requires OPG to prepare a new or amended reference plan in the event of a material change, which includes reductions in the remaining operating period for a nuclear station and any change in circumstances or assumptions that would cause a change in estimated costs by more than an agreed amount.

Under the ONFA, the Province limits OPG's financial exposure for used fuel management with respect to the first 2.23 million used fuel bundles, a threshold that OPG expects will be reached in 2011. OPG is fully responsible for costs of managing used fuel bundles in excess of that amount. The Province also guarantees an annual rate of return of 3.25% above the Ontario Consumer Price Index on the portion of the used fuel fund related to the first 2.23 million used fuel bundles. Actual returns in excess of the guaranteed return accrue to the Province, not OPG.

OPG contributed approximately $4.2 billion to the segregated funds during the five years ended December 31, 2007.[38] The Province made a substantial one-time contribution to the decommissioning fund in 2003. The decommissioning fund had a fair value of approximately $5.1 billion at December 31, 2007 and is considered to be overfunded under the provisions of the ONFA.

At the end of 2007, the fair value of the investments held in the used fuel fund was approximately $4.2 billion, after deducting $511 million relating to excess earnings that accrue to the Province. A revised schedule for OPG's contributions to the used fuel fund was approved by the Province in March 2008. That schedule shows OPG making contributions of approximately $2.1 billion to the used fuel fund over the ten-year period 2008 to 2017, with smaller amounts being contributed thereafter.

[38] Exhibit J15.11, page 4.

5.1.3 Financial reporting

For external financial reporting purposes, OPG accounts for its nuclear liabilities in accordance with the requirements of Section 3110 of the Handbook of the Canadian Institute of Chartered Accountants (CICA).

Section 3110 defines an asset retirement obligation (ARO) as:

> [A] legal obligation associated with the retirement of a tangible long-lived asset that an entity is required to settle as a result of an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel.[39]

OPG's nuclear liabilities meet the definition of an ARO.

Section 3110 requires that an entity recognize the fair value of an ARO as a liability on its balance sheet in the period in which it is incurred, provided a reasonable estimate of fair value can be made. The fair value of an ARO is generally calculated by discounting expected future cash flows, the approach used by OPG.

When an ARO is recognized as a liability, Section 3110 requires that an equal amount be recorded as an increase in the net book value of the related long-lived assets. The addition to net book value is referred to as an asset retirement cost (ARC). An ARC is amortized over the useful life of the assets in the same manner as any other capital cost related to the asset.

Section 3110 is essentially the same as the United States accounting standard on asset retirement obligations issued by the Financial Accounting Standards Board (FASB) in 2001.

The net book values of OPG's nuclear stations include material amounts of unamortized ARC, as shown in Table 5-2.

[39] CICA Handbook Section 3110, "Asset Retirement Obligations," paragraph .03 (a), issued March 2003. OPG adopted Section 3110 in 2003 and retroactively applied the new standard to financial statements for earlier periods.

Table 5-2: Nuclear ARO and ARC Amounts on OPG's Balance Sheet

$ millions at December 31	2005	2006	2007	2008 Forecast	2009 Forecast
Pickering and Darlington					
Fixed asset net book value	$ 2,493	$ 2,924	$ 2,826	$ 2,762	$ 2,630
Unamortized ARC in net book value	$ 1,013	$ 1,435	$ 1,301	$ 1,181	$ 1,061
Unamortized ARC as % of NBV	41%	49%	46%	43%	40%
Nuclear liabilities (ARO)	$ 5,009	$ 5,714	$ 5,921	$ 6,182	$ 6,466
Bruce					
Fixed asset net book value	$ 492	$ 1,271	$ 1,195	$ 1,128	$ 1,063
Unamortized ARC in net book value	$ 388	$ 1,188	$ 1,128	$ 1,080	$ 1,032
Unamortized ARC as % of NBV	79%	93%	94%	96%	97%
Nuclear liabilities (ARO)	$ 3,558	$ 4,614	$ 4,860	$ 5,025	$ 5,213

Sources: Ex. B3-3-1, Tables 1 and 2; Ex. B3-5-1, Tables 1 and 2; Ex. G2-2-1, Table 2; Ex. J1.5; and Ex. J15.1, Addendum #2.

An entity must recognize period-to-period changes in the ARO liability due to the passage of time (accretion expense) and due to revisions to the timing or amounts of the expected future cash flows required to carry out the asset retirement activities. Accretion expense is a charge against earnings. Increases or decreases in AROs due to changes in cost estimates are accounted for the same as the initial recognition of an ARO – they give rise to an equivalent amount of ARC, which is an adjustment to the net book value of the related long-lived assets.

At the end of 2006, OPG revised its cost estimate for nuclear waste management and recorded a $1,386 million increase in the nuclear liabilities and a corresponding increase in the net book values of the nuclear plants ($509 million related to Pickering and Darlington and $878 million related to the Bruce stations).

In its GAAP income statement, OPG books expenses for accretion, depreciation of ARC, and variable waste management expenses (this last expense arises because the nuclear liabilities increase as more nuclear fuel is used each period). OPG also books the earnings on, and change in fair value of, assets held in the segregated funds. Table 5-3 shows the forecast pre-tax charge in OPG's income statement due to the nuclear liabilities and the segregated funds.

Table 5-3: Forecast GAAP Expense – Nuclear ARO, ARC, Segregated Funds

$ millions, periods ending December 31	2008 nine months	2009	Total
Pickering and Darlington			
Depreciation of ARC	$ 90	$ 120	$ 210
Nuclear waste variable expense	16	23	39
Accretion expense	251	344	595
Segregated fund earnings	(186)	(264)	(450)
Total - Pickering, Darlington	**$ 171**	**$ 223**	**$ 394**
Bruce			
Depreciation of ARC	$ 36	$ 48	$ 84
Nuclear waste variable expense	19	17	36
Accretion expense	201	282	483
Segregated fund earnings	(176)	(262)	(438)
Total - Bruce	**$ 80**	**$ 85**	**$ 165**

Sources: Ex. H1-1-3, page 2; Ex. J1.5; Ex. J7.2; Ex. 8.1; Ex. J15.1, Addendum #2.

5.2 OPG's Proposed Treatment of Nuclear Liabilities

Section 6(2)8 of O. Reg. 53/05 requires the Board to ensure that OPG recovers the "revenue requirement impact of its nuclear decommissioning liabilities arising from the current approved reference plan". OPG proposed the following ratemaking approach for nuclear liabilities related to the prescribed facilities, and the related segregated funds, for the test period:

- Depreciation of the ARC component of the net book value of the prescribed nuclear plants is included in the test period revenue requirement.
- Nuclear waste variable costs for Pickering and Darlington are included in the revenue requirement as either fuel costs or depreciation.
- The rate base for 2008 and 2009 would include the average net book values of OPG's Pickering and Darlington nuclear stations. Those net book values include significant amounts of ARC as shown in Table 5-2 above. OPG proposed

applying its debt rate and return on equity to the entire rate base, including unamortized ARC, to determine the revenue requirement.

- Accretion expense and the earnings on segregated funds, both of which affect OPG's reported income under GAAP, are excluded from the revenue requirement under OPG's proposal.

OPG referred to this approach as the "rate base method."

Section 6(2)9 of O. Reg. 53/05 requires that the Board ensure OPG recovers all of the costs it incurs with respect to the Bruce Nuclear Generating Stations ("Bruce stations"). Section 6(2)10 requires that if OPG's revenues from the lease of the Bruce stations exceed its costs, the excess shall be applied to reduce the payment amounts for the Pickering and Darlington facilities. OPG proposed to use the rate base method for nuclear liabilities to calculate its test period costs of the Bruce stations.

Table 5-4 sets out the amounts OPG proposed to recover during the test period in respect of nuclear liabilities. The amounts for depreciation of ARC and nuclear waste variable expenses are the same as the amounts OPG forecasts it will charge to expense in its financial statements (as shown in Table 5-3). For ratemaking purposes, OPG proposed to ignore accretion expense and earnings on segregated funds. Instead, OPG proposed to recover $175 million as a return on the average unamortized ARC of the Pickering and Darlington facilities ($51 million of deemed interest and a return on equity of $124 million). OPG also proposed to include a $161 million return on unamortized ARC in its forecast costs related to the Bruce stations (deemed interest of $47 million and a return on equity of $114 million).

Table 5-4: OPG's Proposed Recoveries Related to Nuclear Liabilities

$ millions, periods ending December 31	2008 nine months	2009	Total
Pickering and Darlington			
Depreciation of ARC	$ 90	$ 120	$ 210
Nuclear waste variable expense	16	23	39
Cost of capital:			
Interest	23	28	51
ROE	56	68	124
Total - Pickering, Darlington	**$ 185**	**$ 239**	**$ 424**
Bruce			
Depreciation of ARC	$ 36	$ 48	$ 84
Nuclear waste variable expense	19	17	36
Cost of capital:			
Interest	20	27	47
ROE	50	64	114
Total - Bruce	**$ 125**	**$ 156**	**$ 281**

Source: Ex. H1-1-3, page 2.

The increase in the nuclear liabilities that OPG recorded at the end of 2006 occurred before the Board assumed responsibility for setting the payment amounts. That increase is nonetheless relevant to this application because the deferral account mandated by Section 5.1 of O. Reg. 53/05 requires OPG to record the "revenue requirement impact" of that increase in the nuclear liabilities for the period up to the date of the Board's first order.

OPG proposed to adopt the same rate base method to calculate the balance in the Section 5.1 deferral account that it proposes to adopt for the test period revenue requirement for Pickering and Darlington. That treatment, which OPG proposed should apply to both the increase in 2006 in the Pickering/Darlington nuclear liabilities <u>and</u> the increase in nuclear liabilities related to the Bruce stations, resulted in OPG recording $75.4 million as a "return on rate base" in the Section 5.1 deferral account.

5.3 The Issues and Board Findings

The ratemaking treatment for nuclear liabilities is complex, and it is made more complex in this case because the issues involve two types of facilities (Pickering and Darlington, which are prescribed facilities under O. Reg. 53/05, and the Bruce stations, which are not prescribed facilities) and two time periods (the test period, and the period prior to the date of the Board's first order.) Some of the relevant issues and considerations are common to both time periods and types of facilities while other issues are unique to a particular time period or type of facility. The Board has chosen to deal with OPG's rationale for its proposal, the positions of the parties, and the Board's findings under four headings:

- Interpretation of O. Reg. 53/05. OPG submitted that the regulation requires the Board to allow OPG to recover costs related to nuclear liabilities using the rate base method. Several intervenors disputed that claim and submitted that the Board has the discretion under the regulation to adopt other methods. Section 5.3.1 below deals with this issue. The Board finds that O. Reg. 53/05 does not obligate the Board to accept OPG's use of the rate base method and that the Board has the discretion to set the revenue requirement using other methods.
- Method of recovering the costs of nuclear liabilities of the prescribed facilities. Section 5.3.2 below reviews the arguments made in favour of and against the rate base method, and the alternatives suggested by intervenors. This section is restricted to the test period revenue requirement of the nuclear liabilities of the prescribed nuclear facilities, Pickering and Darlington. The Board has determined that OPG's revenue requirement related to the cost of nuclear liabilities for the prescribed facilities should not be calculated using the rate base method. Instead, the Board finds that OPG shall use a method that provides separate rate base treatment for the amount of unfunded liabilities.
- Section 5.1 and 5.2 deferral accounts. Section 5.3.3 below deals with the question of how the revenue requirement impact of the 2006 change in nuclear liabilities should be calculated for purposes of the deferral account mandated by Section 5.1 of the regulation. It also addresses how OPG should calculate entries into the deferral account mandated by Section 5.2 of O. Reg. 53/05, in the event OPG records a change in its nuclear liabilities after the date of the Board's first order. The Board finds that for each account the revenue requirement impact will

be calculated using the method that was used to set the revenue requirement during the period of time which the account covers.

- Bruce nuclear liabilities. The issue is whether the costs of nuclear liabilities related to the Bruce stations, which are not prescribed facilities, should be calculated in the same manner as the costs related to the prescribed facilities, or whether a different methodology should be used. This issue is addressed in Chapter 6 of this decision.

5.3.1 O. Reg. 53/05 and nuclear liabilities

Section 6(1) of the regulation states: "Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act." Nuclear liabilities are referred to in Section 6(2)8, which requires that: "The Board shall ensure Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan." The regulation does not contain definitions of "revenue requirement" or "revenue requirement impact."

OPG took the position that the regulation requires the Board to allow OPG to recover nuclear liability costs using the rate base method. OPG submitted that both:

(i) Section 6(2)5(i) of O. Reg. 53/05, which requires the Board to accept the amounts of assets and liabilities as set out in OPG's 2007 audited financial statements, and

(ii) Section 6(2)6(ii), which states that Section 6(2)5 applies to values relating to the revenue requirement impact of accounting and tax policy decisions,

make it clear that asset values resulting from accounting policy decisions approved by OPG's auditors and OPG's Board of Directors must be accepted by the Board in making its first order.

The net book value of nuclear fixed assets set out in OPG's 2007 audited financial statements includes material amounts of unamortized ARC (as shown in Table 5-2 above). OPG submitted that those fixed asset amounts must be accepted into rate base because those amounts appear in the financial statements. OPG claimed that any other interpretation of Sections 6(2)5 and 6(2)6 would "render them meaningless and totally ineffective." OPG asserted that accepting ARC into rate base but attaching a different cost of capital to that element of rate base would contravene the clear intention of those two sections of the regulation.

OPG also submitted that O. Reg. 53/05's provisions for the deferral accounts authorized by Sections 5.1 and 5.2 support its view that the test period revenue requirement must be set using the rate base method. Those deferral accounts capture the "revenue requirement impact" of certain changes in nuclear liabilities before (Section 5.1) or after (Section 5.2) the date of the Board's first order. Section 6(2)7 requires those revenue requirement impacts to be based on four items as "reflected in" OPG's financial statements, including a "return on rate base."[40] OPG argued that there would be no meaning to this provision if the regulation did not require the Board to use the rate base method. OPG argued that it would be capricious and arbitrary to employ one method to calculate deferral account balances related to *changes* to nuclear liabilities as a result of new reference plans (Sections 5.1 and 5.2) and a different method to set the revenue requirement impact of those changes for the test period (Section 6(2)8).

CCC, CME (supported by AMPCO), SEC, VECC and Board staff disagreed with OPG's interpretation of O. Reg. 53/05.

CCC submitted that the regulation does not directly, or by necessary implication, require the Board to accept the rate base method for the costs of nuclear liabilities. CCC also submitted that although the Board is required by Section 6(2)5 to accept amounts set out in OPG's financial statements, the Board is not required to adopt all of the accounting and ratemaking assumptions therein.

CME acknowledged that Sections 6(2)5 and 6(2)6 require the Board to accept amounts set out in OPG's financial statements. CME submitted, however, that the "revenue requirement impact" of nuclear liability costs is an item of regulatory policy, not an item of tax or accounting policy. CME argued that the regulation does not empower OPG and its auditors to make a regulatory policy determination with respect to the recovery of costs associated with nuclear liabilities. CME also submitted that if the recovery of the costs of nuclear liabilities is a matter of accounting policy, and not regulatory policy, then GAAP provisions relating to expensing of nuclear liability costs should apply. Yet,

[40] The four items are: return on rate base; depreciation expense; income and capital taxes; and fuel expense.

CME noted, OPG's rate base method disregards and does not apply GAAP to calculate the amount of expense related to nuclear liabilities.

SEC urged the Board to reject OPG's proposition that the inclusion of nuclear liability costs in the revenue requirement has been predetermined by the regulation. SEC observed that OPG does not cite any specific provision of O. Reg. 53/05 that directs the Board to accept the rate base method and noted that "revenue requirement impact" is not defined in the regulation. SEC submitted that the regulation leaves it to the Board to determine the revenue requirement related to the cost of nuclear liabilities.

SEC disagreed with OPG's submission that the reference to "return on rate base" in Section 6(2)7, which deals with the deferral accounts for changes in nuclear liabilities, supports a conclusion that the regulation requires OPG's rate base method. SEC pointed out that while Section 6(2)7 requires revenue requirement impacts to be based on four items as reflected in OPG's audited financial statements, one of which is a "return on rate base," OPG's audited financial statements do not contain any items called "return" or "rate base." SEC argued that on a plain reading of Section 6(2)7, <u>no</u> return on rate base could be permitted as there is no item called "return on rate base" in the financial statements; a plain reading of the other parts of Section 6(2)7 would lead to similarly absurd results. [41] For these reasons, SEC submitted that the government, in enacting the regulation, did not intend Section 6(2)7 to be read literally, and did not intend that the entire decision-making responsibility for recovering the costs of nuclear liabilities be granted to OPG's Board of Directors.

SEC submitted that:

> … this Board should not fetter its discretion to determine payment amounts under s. 78.1 on the basis of an implied direction in s. 6(2)7. The Board should only decline jurisdiction when its mandate is clearly and expressly circumscribed, which is not the case here. The alternative is for the Board to implement rate recovery for nuclear negative salvage on a basis that the Board knows (or at least suspects) is not just and reasonable, on the theory that the government

[41] Of the three remaining items, SEC pointed out that depreciation expense is included in the financial statements but not normally disaggregated into line items; income and capital taxes are accounted for differently for regulatory and accounting purposes, and a literal reading of section 6(2)7 would require the application of conventional deferred tax accounting to the regulatory sphere, a significant and major change in regulatory process that is unlikely to have been implemented by the government without express direction; and fuel expense, another of the four items, is not separately set out in the financial statements. (SEC Argument, paragraph 194.)

> may have indirectly limited the Board's jurisdiction to do what is right.[42] (emphasis in original)

VECC submitted that whether and how a particular accounting item is included in the regulatory construct of "rate base" is entirely at the discretion of the Board, and is not something imposed on the Board by a non-regulatory accounting policy. VECC acknowledged that although the accounting treatment for an item can provide guidance in a regulatory context, the method of accounting is not determinative of the appropriate regulatory treatment.

Board staff submitted that Sections 6(2)5 and 6(2)6, on which OPG relies in its argument, must be read in conjunction with Section 78.1(4) of the *OEB Act*[43] and Section 6(1) of O. Reg. 53/05. Board staff concluded that:

> … while the Board must accept the amounts and certain values set out in the audited financial statements when making its first order, the Board's discretion in dealing with matters which are placed in rate base, either through the operation of the Regulation or as a result of its own determination of the composition of rate base, remains. Board staff submits that it is open to the Board to determine whether a different cost of capital should be applied to an element of rate base.[44]

In its reply argument, OPG submitted that O. Reg. 53/05 does not confer any jurisdiction on the Board with respect of the recovery of the cost of nuclear liabilities. OPG asserted that the regulation merely confirms the continuation of what OPG describes as the status quo – the use of the rate base method.

OPG argued that the phrase "revenue requirement impact" used in Section 6(2)7 does not convey total discretion to the Board, as CME and the other intervenors suggest. In OPG's view, the role of the Board is quite limited. OPG submitted that the phrase "to the extent the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts" in Section 6(2)7:

[42] SEC Argument, paragraph 201. "Nuclear negative salvage" is the term that SEC used to describe nuclear decommissioning liabilities.

[43] Section 78.1(4) of the *OEB Act* states: "The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment."

[44] Board Staff Argument, page 14.

> … obligates the OEB to ensure that OPG has accurately calculated the "revenue requirement impacts" and recorded the correct figures in the deferral account; it has nothing to do with the methodology that the OEB must follow for determining the "revenue requirement impacts."[45]

OPG claimed that a conclusion that the Board retains discretion over the composition of rate base and the return on ARC would make a complete mockery of Sections 6(2)5 and 6(2)6 of the regulation. OPG asked: "If the OEB must accept the ARC as a fixed asset but is free to assign it a zero cost [a position advocated by some intervenors], how has the Board "accepted" anything?"[46]

OPG claimed that the Province of Ontario knew, when it approved O. Reg. 53/05 in 2005, that the initial payment amounts were set using the rate base method for the costs of nuclear liabilities. OPG submitted this is an important factor to be considered when interpreting Sections 6(2)5 to 8 of the regulation. OPG also claimed that the Province is aware that OPG used the rate base method in preparing this application and the interpretation of the regulation that it was putting forward, namely, that the regulation required the Board to ensure OPG recovers nuclear liability costs calculated using the rate base method. OPG stated: "As the sole shareholder, if OPG's request was out of line with the intent of O. Reg. 53/05, it would be reasonable to expect that the Province would have so advised the company."[47]

Board Findings

The Board does not accept OPG's position that O. Reg. 53/05 requires the Board to ensure OPG recovers nuclear liability costs calculated using the rate base method. The Board finds it has discretion to determine the method that OPG should use to calculate and so recover the revenue requirement impact of the nuclear liabilities.

Section 6(2)8 of O. Reg. 53/05 obligates the Board to ensure OPG recovers the revenue requirement impact of its nuclear liabilities. Section 6(1) of O. Reg. 53/05 specifies that the Board "may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts." The only restriction in Section 6(1) is that a Board order is subject to the provisions of section 6(2). The Board has concluded that none of the provisions of section 6(2) require the

[45] OPG Reply Argument, page 127.

[46] OPG Reply Argument, page 126.

[47] OPG Reply Argument, page 126.

rate base method be used to calculate the revenue requirement impact referred to in Section 6(2)8.

The Board reached this conclusion for several reasons.

First, the regulation does not define “revenue requirement impact” and does not state anywhere that the rate base method must be used to determine the cost of nuclear liabilities. In its role as economic regulator of electric and natural gas utilities, the Board has many years of experience in setting the revenue requirements of the entities it regulates. Determining what items should be included in an entity’s revenue requirement, and how those items should be measured, is one of the most important functions of an economic regulator. Had the government intended that the Board relinquish the jurisdiction to determine how the revenue requirement should be calculated, it could have included clear and unambiguous language to that effect in the regulation. It did not do so.

The Board notes that OPG was unable to provide any examples from other North American jurisdictions of the rate base method being used to calculate the costs of nuclear liabilities. While the lack of examples does not invalidate the method, it certainly casts doubt on OPG’s contention that, notwithstanding the lack of any explicit statement, the government clearly intended that only the rate base method be used. The Board cannot accept that the government intended to require the Board to accept a method not known to be used in any other jurisdiction yet did not consider it necessary to make this requirement explicit in the regulation.

Second, the Board does not agree with OPG’s interpretation of the sections of O. Reg. 53/05 concerning acceptance of amounts in OPG’s 2007 financial statements. OPG correctly pointed out that Section 6(2)5 of the regulation requires the Board to accept the net book values of OPG’s fixed assets as set out in its 2007 audited financial statements. It also noted that those net book values include substantial amounts of unamortized ARC (as shown in Table 5-2 above). OPG then asserted: “According to O. Reg. 53/05, the OEB must accept into rate base OPG’s prescribed fixed asset values.”[48] The Board does not agree that OPG’s conclusion follows from the requirements of Sections 6(2)5 or 6(2)6.

[48] OPG Argument-in-Chief, page 83.

Section 6(2)5 requires the Board to accept the amounts of certain items as set out in OPG's financial statements. In the Board's view, the purpose of this section was to limit the extent to which the Board and intervenors could go back in history and question the impact of OPG's past accounting decisions on amounts that were determined before the Board took over the responsibility for setting payment amounts. A requirement to accept certain amounts is not an instruction as to how the Board should use those amounts in determining OPG's revenue requirement. The Board notes that when it is intended that the Board ensure OPG recover certain amounts, O. Reg. 53/05 is explicit. For example, Section 6(2)4 obligates the Board to ensure OPG recovers nuclear refurbishment costs. In contrast, Sections 6(2)5 and 6(2)6 do not require the Board to ensure recovery of any amounts or to use certain methodologies, and do not circumscribe the Board's authority as set out in Section 6(1).

Third, the Board is not persuaded by OPG's argument that the reference to "return on rate base" in Section 6(2)7 on nuclear liability deferral accounts supports a conclusion that O. Reg. 53/05 obligates the Board to accept the rate base method for the cost of OPG's nuclear liabilities.

As more fully explained in section 5.3.3 of this decision on nuclear liability deferral accounts, the Board has concluded that the term "return on rate base" in Section 6(2)7 does not restrict in any way how the Board determines the revenue requirement impacts under Section 6(2)8. The Board's interpretation of Sections 5.1, 5.2, and 6(2)7 is that those sections require that OPG be "kept whole" when its nuclear liabilities increase in response to a new reference plan. However, contrary to OPG's interpretation, the Board finds that those sections do not specify how to calculate the amounts that would keep OPG whole.

The Board finds that O. Reg. 53/05 does not require the Board to use the rate base method when determining the revenue requirement impact for purposes of Section 6(2)8.

5.3.2 Recovering the cost of nuclear liabilities related to Pickering and Darlington

Having found that the Board is not required by O. Reg. 53/05 to accept OPG's use of the rate base method for the costs of nuclear liabilities, the Board considered the merits of various methods, including the rate base method, of recovering the costs.

In addition to OPG's rate base method, four other methods of determining the revenue requirement impact of the nuclear liabilities were discussed during the hearing. Those methods and OPG's rate base method are summarized in Table 5-5, which is based on calculations filed by OPG. The table deals only with the "return on rate base" aspects of each method. It omits depreciation of unamortized ARC and the other elements of the revenue requirement proposed by OPG that were not opposed by any party. Table 5-5 includes amounts for both the prescribed assets (Pickering and Darlington) and the Bruce stations. (The Board did not have all of the information required to separate the Bruce amounts from the amounts for Pickering and Darlington.) Cost of capital in the table is based on OPG's application (a capital structure of 42.5% debt, 57.5% equity; proposed debt rates of 5.65% in 2008 and 6.47% in 2009; and a return on equity of 10.5%).

In their arguments, some intervenors proposed new approaches or variations on the methods shown in Table 5-5.

Table 5-5: Comparison of Methods to Calculate the Revenue Requirement for Nuclear Liabilities

$ millions	OPG's Rate Base Method	CIBC Option 2	Flow-through Method	Method 3	Method 3(b)
Rate base	Average unamortized ARC ($2,325 million for 2008 and $2,178 million for 2009)	Rate base per OPG, less average unfunded nuclear liability ($1,231 million for 2008 and $878 million for 2009)	Zero	Same as OPG's rate base method	Same as CIBC Option 2
Revenue requirement	Cost of capital applied to rate base	Cost of capital applied to rate base. Revenue requirement also includes total forecast accretion expense and total forecast segregated fund earnings	Total forecast accretion expense, less total forecast segregated fund earnings	Cost of capital applied to rate base. Cost of debt is based on a blend of the OPG's average accretion rate of 5.6% (for the amount of the unfunded liability) and the forecast long-term debt rate (for the balance of deemed debt)	Cost of capital applied to rate base. The revenue requirement for the unfunded liability is based on OPG's average accretion rate of 5.6%
Cost of capital	$334.3	$180.9	-	$326.2	$179.3
Accretion expense	-	1,074.7	1,074.7	-	100.9
Segregated fund earnings	-	(888.1)	(888.1)	-	-
Revenue requirement	**$334.3**	**$367.5**	**$186.6**	**$326.2**	**$280.2**

Sources: Ex. J12.1, Attachment 1; Ex. H1-1-3, page 2; Ex. J7.1

Note 1: Amounts in the table relate to both the prescribed nuclear facilities and the Bruce stations.

Note 2: The amounts in the table are all taken from an OPG-prepared exhibit. The Board notes that the cost of capital amounts shown for CIBC Option 2 and Method 3(b) are different. Those amounts should be identical, however, given that the rate base for each method is the same. "CIBC Option 2" is contained in a report written in December 2004 by CIBC World Markets, commissioned by the government to assist it in determining the current payment amounts.

OPG noted that its total proposed revenue requirement for nuclear waste management and decommissioning costs (as shown in Table 5-4) would be less than the company's cash flow requirements during the test period (expected contributions to the segregated funds and nuclear costs funded through operations).

In addition to its argument that the regulation requires the Board to accept use of the rate base method (see section 5.3.1 above), OPG argued that the Board should approve the use of the method because it was used by the government when it set the current payment amounts in 2005, and it is the most appropriate methodology.

OPG referred to a December 2004 report from CIBC World Markets to support its contention that the rate base method was used to set current payment amounts. That report provided CIBC's analysis and advice on the initial regulated payment amounts for the prescribed assets. CIBC described two methods of dealing with nuclear liabilities. CIBC's preferred method, which it submitted followed traditional rate base methodology, involved recovering the unfunded liability through OPG's return on assets. CIBC acknowledged that this method "effectively requires rate payers to fund a higher cost of capital associated with the unfunded liability than the interest rate used in calculating the liability pursuant to ONFA."[49] This method is summarized in Table 5-5 under the heading "OPG's Rate Base Method".

CIBC also described an alternative method that involved removing the unfunded liability from rate base, which would lower OPG's return on capital, and collecting interest at the rate used under the ONFA to calculate the liability. This method is summarized in Table 5-5 under the heading "CIBC Option 2". According to CIBC, this method would have lowered the initial payment amounts by $1 per MWh.

OPG acknowledged that the various payments amounts discussed in the CIBC report are not the same as the payment amounts set by the government effective April 1, 2005. Part of the reason for the difference is that the payment amounts in the CIBC report were based on a 10 per cent return on equity while the government used a five per cent rate to set the initial payments. OPG's evidence was that the CIBC report and the initial rates were "entirely consistent in every regard, except for their recommendation on return on equity."[50] OPG concluded that the government must have used CIBC's preferred method, which OPG submitted is the same as its rate base method, to set the initial payments.

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[49] CIBC World Markets Inc., *Engagement Review of Financial Advisory Services on OPG's Initial Regulated Rate and Financial Soundness*, December 2004, page 19. [Exhibit L-2-10, Attachment 1]

[50] Transcript Volume 1, page 78.

OPG submitted that the rate base method is “the best and most appropriate method to recover OPG’s nuclear waste management costs.”[51] The CICA Handbook requires ARC to be included in the net book value of fixed assets and depreciated like any other element of asset cost. OPG considered that to be a rational allocation of the costs over the lives of the related assets. OPG also submitted that no investor would invest in nuclear generation if no consideration were given to the capital required to finance ARC.

OPG submitted that the rate base method is consistent with traditional regulatory practice in that it does not require “streaming” of particular costs to particular assets.

OPG noted that the revenue requirement that results from using the rate base method is not tied to the level or pace of cash contributions to the segregated funds or to fund earnings. An OPG witness submitted that:

> … we feel that any approach that involves nuclear fund earnings is going to result in volatility of regulatory earnings, as well as increased regulatory burden associated with scrutiny of those forecasts, and that earnings can be volatile is certainly illustrated by things that occurred in the early part of this year …[52]

CCC, CME (supported by AMPCO), SEC, and VECC objected to OPG’s proposed rate base method. Other intervenors were silent on the issue.

There were three arguments against OPG’s use of the rate base method that appeared in various forms in the written submissions of the intervenors. Those arguments are summarized below, followed by a description of the alternative approaches suggested by the intervenors.

First, intervenors argued that a rate base return on capital should be allowed only when capital has been supplied by debt or equity investors. Most intervenors who opposed OPG’s use of the rate base method submitted that ARC is not funded by debt and equity and, therefore, none of that amount should attract a return equal to OPG’s weighted average cost of capital (WACC). (CCC seemed to suggest that some amount

[51] OPG Argument-in-Chief, page 82.

[52] Transcript Volume 7, page 46. The event in the early part of the year referred to by the OPG witness was OPG’s recognition of a loss of $51 million on the segregated funds in the first quarter of 2008, compared to earnings of $91 million in the first quarter of 2007.

of ARC should attract a return equal to WACC.) SEC's comment on funding of nuclear liabilities and ARC is typical:

> The use of rate base to calculate the amount of allowable debt (and therefore interest recovery), and the amount of allowed equity (and return on it), presupposes that this amount of capital is needed by the utility to operate. That is, the regulatory methodology used starts from the assumption that the utility needs to be capitalized by an amount equal to the rate base, through issuing either debt or equity. That assumption is only correct where the rate base involves real capital expenditures, actually incurred or needing to be funded.
>
> That is not true in the case of nuclear negative salvage. No money has been spent, and no capital has been raised through debt or equity.[53]

Second, intervenors noted there is no precedent in North America for the use of the rate base method for ARC, and this was acknowledged by OPG. Neither of the two owners of other nuclear generation facilities in Canada, Hydro-Québec and New Brunswick Power, are subject to cost-of-service regulation for nuclear output. With respect to rate regulated nuclear plants in the United States, OPG's expert on cost of capital provided her views on the impact of FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, which is virtually identical to CICA Handbook Section 3110. She indicated that "FASB 143 has not resulted in material changes in regulatory practice with respect to rate base or capital structure for U.S. utilities with ARCs and AROs."[54]

VECC noted that the U.S. Federal Energy Regulatory Commission (FERC) has not mandated a single method of dealing with recovery of asset retirement costs. VECC filed FERC Order No. 631, which deals with accounting and rate filing requirements for asset retirement obligations, and which states: "The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by the public utilities, licensees, and natural gas companies."[55]

Third, contrary to OPG's submission, the intervenors took the position that how the government treated ARC when it set the current payment amounts on April 1, 2005 is

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[53] SEC Argument, paragraphs 212 and 213.

[54] Addendum to Exhibit J1.3, page 4.

[55] Federal Energy Regulatory Commission, Docket No. RM02-7-000, Order No. 631, *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, April 9, 2003, paragraph 62. [Exhibit K11.7]

not relevant in this proceeding and not binding on the Board. CCC submitted that to imply the ratemaking treatment for 2008 and 2009 must be consistent with the 2005-2007 interim rates is tantamount to stating that the interim rates established a binding precedent.

SEC submitted that with respect to ARC, it is not clear what the government took into account when it set the initial payment amounts. SEC submitted that:

> [T]he Board is not in a position to look at how the Legislature's decision on nuclear negative salvage was made, the evidence the Legislature considered, or whether the specific circumstances of that decision are different from the current situation.[56]

SEC argued that the government's earlier decision should not influence the Board's consideration of the issue in this case.

Intervenors recommended alternative approaches to setting the revenue requirement.

CCC agreed that ARC should be included in rate base and that depreciation of that amount should be an allowable cost. CCC submitted, however, that the Board should distinguish between the funded and unfunded components of ARC in awarding a return on rate base. CCC proposed that the unfunded part of rate base would equal the average unfunded nuclear liabilities during the test period. It was not clear how CCC would calculate unfunded liabilities. CCC's argument referred to an OPG exhibit that showed the forecast average unfunded nuclear liabilities are $1,231 million for the last nine months of 2008 and $878 million for 2009. Another part of the CCC argument, however, suggests that unfunded liabilities equal annual average ARC minus average annual fund contributions.[57]

CCC submitted that the shareholder should only earn a return on capital raised to date and that customers should not pay for a return on capital that has not been raised. CCC likened unfunded nuclear liabilities to deferred income taxes and submitted that there should be a zero rate of return on the unfunded part of rate base.

CCC argued that the calculation of the unfunded portion of rate base would not represent an administrative burden and OPG has overstated the ratemaking difficulties.

[56] SEC Argument, paragraph 177.

[57] CCC Argument, paragraph 111.

CCC claimed that customers would be willing to accept the risk that the unfunded portion of rate base may fluctuate due to conditions in the investment markets in order to defer the cost of funding to future test years when the funds have been raised.

CME recommended including ARC in rate base for the limited purpose of determining depreciation, which CME would allow as a recoverable expense. It argued for excluding ARC from the capital structure for the purposes of determining OPG's cost of debt and equity capital. CME recommended that the Board adopt a method CME called "Cost of Service Supplement to ARC Depreciation." Under this approach, OPG would be permitted to recover "the estimated annual amount needed, over and above the ARC depreciation amount, to produce, at the end of the economic life of the nuclear assets, the portion of the fund needed to retire and decommission the assets which will not be funded by ARC depreciation and interest accruals thereon."[58] CME's argument contained calculations to illustrate how its proposed method might work.

CME proposed, as a surrogate for its recommended approach, that OPG be permitted to recover 4.6% per annum on the unamortized balance of ARC included in rate base during the test period.[59] CME asserted that the combination of ARC depreciation and this 4.6% return would "be more than sufficient to produce, at the end of the economic life of the nuclear assets, the unfunded portion of the total undiscounted liability which gave rise to ARC."[60] CME also urged the Board to characterize its determination on these issues as interim only. It recommended that the Board sponsor, before OPG's next application, a consultation on the regulatory treatment of nuclear decommissioning costs, a process that could consider the results of the National Energy Board's ongoing assessment of retirement costs with respect to abandonment of pipelines.[61]

AMPCO supported CME's recommended approach, and also advocated that the Board undertake further review of the ratemaking treatment of ARC.

[58] CME Argument, paragraph 91.

[59] CME refers to 4.6% as the "prevailing discount rate." [CME Argument, paragraph 113] The Board understands, however, that only a portion of the $10.8 billion ARO liability at December 31, 2007 (being the $1,386 million increase that was booked at the end of 2006) has been calculated using a 4.6% discount rate; the balance of the ARO liability has been measured using a 5.75% discount rate.

[60] CME Argument, paragraph 97.

[61] See National Energy Board Discussion Paper, *Land Matters Consultation Initiative, Stream 3: Financial Issues Related to Pipeline Abandonment*, March 2008.

SEC submitted that the Board has insufficient evidence to determine whether OPG's rate base method produces a just and reasonable result. SEC urged the Board to accept an adjusted rate base method for making its first order under Section 78.1 and to order a more detailed review of the regulatory treatment of nuclear liabilities before OPG's next application. SEC recommended that the Board accept the amount of depreciation expense proposed by OPG for the test period but that it not award the return on unamortized ARC that was proposed by OPG. Instead, SEC recommended that the Board allow a return of 4.6% on average unamortized ARC in rate base.[62]

VECC supported granting a return on unamortized ARC that is lower than the weighted average cost of capital. It advocated a sinking fund approach to recovery of nuclear liability costs, an approach that was not set out in detail in VECC's argument. VECC said one way to implement its sinking fund method would be to adopt the treatment recommended by CME. VECC did not comment on whether OPG should be allowed to recover depreciation of ARC.

By recommending that the Board isolate a portion of rate base and attribute a different return to that component, the intervenors support "streaming" of costs to the particular assets, a practice opposed by OPG. CCC, CME and VECC submitted that the Board has the discretion to determine the cost of capital to be applied to any element of rate base, a position also taken by Board staff. VECC submitted that the two Board decisions cited by OPG as precedents for not streaming financing costs are not relevant because they involved relatively small amounts of rate base and because "streaming" was not at issue in the cases.[63]

In its reply argument, OPG stated that most of CME's assumptions, claimed facts and calculations in respect of CME's proposed method had not been put into evidence or tested in the hearing, and that many of them were wrong. OPG submitted that the Board should disregard CME's new calculations of the revenue requirement.

OPG disagreed with the intervenors that cited the normal regulatory practice of awarding no return on deferred tax balances as support for their recommendation that

[62] SEC described its proposed 4.6% rate as "the discount rate used to discount the future liabilities to the present." [SEC Argument, paragraph 214] As noted in footnote 12, only a portion of the current ARO liability (being the $1,386 million increase that was booked at the end of 2006) has been calculated using a 4.6% discount rate. A higher discount rate applies to the balance of the ARO liability.

[63] VECC Argument, paragraph 38. The two Board decisions cited by OPG, in the addendum to Exhibit J1.3, were: Toronto Hydro (EB-2007-0680) and Centra Gas (EBRO 474).

there be no return on unamortized ARC. OPG pointed out that deferred taxes are considered to be a form of no cost capital because customers have already prepaid taxes through rates. That is not the case for OPG's nuclear liabilities.

OPG opposed the interim treatment advocated by the intervenors. In OPG's view, its proposal on nuclear waste management and decommissioning costs has been clear since the start of this proceeding. Intervenors have had the opportunity to gather evidence through the Technical Conference, interrogatories and cross-examination of OPG witnesses. OPG also asserted that deferring a final decision on the method of recovering the costs would result in a significant risk for OPG, and would require further consideration of the cost of capital when the final nuclear waste methodology is determined.

Board Findings

In the Board's view, there is no doubt that the cost of nuclear liabilities should be included in the revenue requirement for the prescribed facilities. Managing nuclear waste, and decommissioning the plants at the end of their lives, is an integral part of operating the Pickering and Darlington plants. The issue is not whether such costs should be recovered by OPG but, rather, how those costs should be measured for ratemaking purposes.

As noted by OPG and intervenors, there does not appear to be any consistent and generally accepted treatment of AROs and ARCs in other North American jurisdictions. The standards governing the financial accounting for AROs are relatively new. The FASB in the United States issued Statement No. 143 in 2001, and the CICA Handbook section 3110 in 2003. Whether North American regulators will ultimately modify their ratemaking approaches to be compatible with the accounting standards is not clear.

Given the newness of the financial accounting standards for AROs, and the apparent lack of any consensus among regulators about whether to accept a rate base that includes ARC, the Board is not prepared to accept use of the rate base method in precisely the form proposed by OPG.

The Board will accept inclusion in the revenue requirement of depreciation expense for the nuclear plants computed in accordance with GAAP, as proposed by OPG. Under GAAP, ARC included in the net book value of fixed assets is depreciated like any other fixed asset cost. It appears as an expense in OPG's income statement. The Board finds that this approach results in a rational allocation of cost. Several intervenors explicitly supported that approach and no intervenor objected to it.

The more difficult issue is whether OPG should be permitted to recover its cost of capital on a rate base that includes 100% of unamortized ARC. There was no evidence provided at this hearing that any regulator has yet permitted the inclusion of ARC in rate base. Indeed, the policies of FERC in the United States specifically require that:

> … all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment. If the public utility, licensee or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates.[64]

Under accounting standards that existed before the release of FASB Statement No. 143 and CICA Handbook Section 3110, it was reasonable to conclude that the original cost of fixed assets on a regulated entity's balance sheet had been financed by investor-supplied debt and equity funds. While that remains true for many regulated entities, it clearly is no longer true for entities that have booked AROs.

When OPG increased its nuclear liabilities by $1,386 million at the end of 2006, and increased its fixed asset book values by the same amount, it did not have to arrange a debt or equity issue, or invest some of its retained earnings. All that happened was that OPG posted a journal entry to its general ledger – it debited fixed assets for $1,386 million and credited nuclear liabilities for the same amount.

At some point, the unamortized ARC that is included in fixed assets in effect will be funded by debt or equity because OPG is obligated by ONFA to make cash contributions to the segregated funds; however, until those contributions occur, the ARC component of fixed assets has not been funded with capital supplied by investors.

It would be inappropriate, in the Board's view, to award OPG a rate base-type return on unamortized ARC when OPG has not had to raise the full amount of ARC as new debt or equity. In the Board's view, the rate base method over-compensates OPG when OPG's nuclear liabilities are not fully funded. As CIBC noted in its December 2004 report, the rate base method "effectively requires ratepayers to fund a higher cost of

[64] FERC Order No. 631, paragraph 62.

capital associated with the unfunded liability than the interest rate used in calculating the liability pursuant to ONFA."[65]

The Board finds that OPG should use a variation of Method 3(b) shown in Table 5-5. The Board will accept the rate base for the prescribed nuclear assets as proposed by OPG. Rate base shall be calculated using average annual fixed asset balances that are determined in accordance with GAAP. Those fixed asset balances include unamortized ARC. The return on rate base, however, will not be as proposed by OPG.

The Board will require that the return on a portion of the rate base be limited to the average accretion rate on OPG's nuclear liabilities, which is currently 5.6%. That portion of rate base that attracts that return will be equal to the lesser of: (i) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. When the average unfunded nuclear liabilities exceed the amount of unamortized ARC in fixed assets, then the portion of rate base that attracts the 5.6% return would be capped at the average amount of unamortized ARC; if the average unfunded liabilities are forecast to be lower than the average unamortized ARC, it is appropriate to limit the portion of rate base that attracts the 5.6% return to the unfunded amount. That approach recognizes that OPG has raised debt (or used its retained earnings) to fund part of the unamortized ARC.

For the balance of the rate base, the return on capital should be calculated using the capital structure, debt rate, and return on equity approved by the Board in Chapter 8 of this decision.

The Board has some, but not all, of the information required to calculate the portion of rate base that will attract the 5.6% return. OPG's evidence includes the forecast amounts of average unamortized ARC in the Pickering and Darlington fixed assets ($1,227 million for 2008 and $1,121 for 2009). Its evidence, however, did not include the forecast unfunded liability in respect of Pickering and Darlington (the evidence provided by OPG showed a combined unfunded amount that included amounts related to the Bruce stations). OPG should provide the amounts of forecast average unfunded liabilities related to Pickering and Darlington as part of the information supporting the draft payment order based on this decision.

[65] CIBC Report, page 19.

The Board notes that the method it will require OPG to use to set payment amounts yields much the same result as Option 2 proposed by CIBC in its December 2004 report (Option 2). The CIBC report described the Option 2 calculation as follows: “Remove the unfunded liability from rate base, and instead collect interest as calculated per ONFA on the unfunded liability explicitly in rates.”[66]

The Board agrees with those intervenors who submitted that the cost of capital impact should be based only on amounts of “funded ARC.” The Board did not accept, however, the specific methods advocated by the intervenors.

The Board disagrees with CCC’s submission that OPG should earn no return on unfunded amounts. Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its nuclear liabilities whether they are funded or not.

CME advocated its “Cost of Service Supplement to ARC Depreciation” concept as a model the Board should consider in the future, while VECC advanced a sinking fund method as the right approach. Neither model was fully developed in the intervenor arguments. It appeared to the Board that both models would require the Board to develop an alternative funding schedule in order to calculate the revenue requirement. The Board questions the utility and practicality of developing alternatives to the funding schedule set out in the ONFA.

The Board does not adopt the recommendation from intervenors that the Board’s decision on this issue should be labelled as “interim” or that the Board should launch a consultation process on the ratemaking aspects of asset retirement obligations. The Board agrees with OPG that there was ample opportunity in this proceeding for all parties to explore the issues and alternative treatments. The Board believes the right forum for dealing with this issue is a hearing on an application from OPG. To the Board’s knowledge, no other entity it regulates has recorded any material amounts of AROs. For OPG, the issue is both real and material.

[66] CIBC Report, page 19. The calculations provided by OPG at the hearing and summarized in Table 5-5 indicate a different interpretation of Option 2. The calculation of the revenue requirement in Table 5-5 includes forecast accretion expense on OPG’s entire nuclear liability (which was $10.8 billion at the end of 2007), net of forecast earnings on the segregated funds. By including amounts related to funded liabilities, that calculation appears to be in conflict with the description of the Option 2 calculation in the CIBC report, which refers to unfunded liabilities only.

Before the hearing on OPG's next payment amounts application is completed, the National Energy Board, Provincial regulatory bodies, FERC, or other bodies may issue position or policy papers or release decisions dealing with AROs. If such external developments occur, OPG, intervenors, and Board staff will have the opportunity in that hearing to submit evidence and argue for a different approach to AROs.

5.3.3 Section 5.1 and 5.2 deferral accounts

O. Reg. 53/05 was amended in 2007 to require OPG to establish a deferral account to capture certain amounts related to changes in nuclear liabilities that occurred after April 1, 2005 and before the effective date of the Board's first order (Section 5.1), and after the date of the Board's first order (Section 5.2). O. Reg. 53/05 states:

> **Nuclear liability deferral account, transition**
>
> **5.1** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.
>
> (2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually.
>
> **Nuclear liability deferral account**
>
> **5.2** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,
>
> (a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and
>
> (b) the liability arising from the current approved reference plan.
>
> (2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct.

On December 31, 2006 OPG recorded an increase of $1,386 million in its nuclear decommissioning and nuclear waste management liabilities. In accordance with Canadian GAAP, the increase in the nuclear liabilities was added to the net book value of the relevant nuclear stations. The net book value of the Bruce stations was increased by $878 million (to $1,271 million at the end of 2006), and the net book value of the Pickering and Darlington stations was increased by $508 million (to $2,454 million at the end of 2006).[67]

OPG's 2006 financial statements described the basis for the change in the liabilities and the impact the change would have on OPG's future financial results:

> The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. As at December 31, 2006, OPG updated the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities. The resulting updated Reference Plan ("2006 Approved Reference Plan") was approved by the Province in accordance with the terms of the ONFA [Ontario Nuclear Funds agreement]. The increase in cost estimates reflected in the Approved Reference Plan is mainly due to additional used fuel and waste quantities resulting from station life extension, recent experience in decommissioning reactors, and changes in economic indices. The increase is partially offset by the deferral of some station decommissioning dates.
>
> As a result of the new Reference Plan, OPG will recognize additional expenses including accretion on the fixed asset removal and waste management liabilities and depreciation of the carrying value of the related fixed assets. The impact of these additional expenses will be reduced by the recognition of a regulatory asset to be recovered through future prices charged to customers, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) …[68]

The balance in the Section 5.1 nuclear liability deferral account as at December 21, 2007 was $130.5 million. The components of that balance are shown in Table 5-6. OPG's pre-filed evidence included the components shown in the total column but did not include a breakdown by facility. The figures in the Pickering/Darlington and Bruce columns in Table 5-6 are estimates based on the oral testimony of an OPG witness.

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[67] Exhibit J1.5; Exhibit B1-1-1, Table 2; and Exhibit G2-2-1, Table 2.

[68] OPG 2006 consolidated financial statements, Note 9.

Table 5-6: Nuclear Liability Deferral Account, December 31, 2007

$ millions	Pickering/ Darlington	Bruce	Total
Return on rate base	$ 27.0	$ 48.5	$ 75.4
Depreciation	44.7	9.0	53.7
Capital tax	*n/a*	*n/a*	3.1
Fuel expense	*n/a*	*n/a*	(5.2)
Interest (6%)	*n/a*	*n/a*	3.5
Total	**$ 76.5**	**$ 54.0**	**$ 130.5**

Sources: Ex. J1-1-1, page 12, and Transcript Vol. 15, page 86.
n/a - Not available

Section 6(2)7 of O. Reg. 53/05 sets out the maximum recovery period and provides a list of items on which the account balance is to be based:

> 7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,
>
> i. return on rate base,
>
> ii. depreciation expense,
>
> iii. income and capital taxes, and
>
> iv. fuel expense.

OPG has used the rate base method to determine the balance of this deferral account. The “return on rate base” included in the Section 5.1 deferral account was based on the average 2007 balance of the incremental ARC added to the net book value of fixed assets as a result of the increased nuclear liability ($1,359 million), multiplied by a 5.55% return on rate base. The 5.55% return was based on a capital structure of 55% debt and 45% equity, an interest rate of 6%, and a return on equity of 5%. OPG indicated that the capital structure and rates are the same as those used by the Province to set the initial payment amounts.

Submissions from OPG and intervenors on using the rate base method for the Section 5.1 and 5.2 deferral accounts were essentially the same as their arguments in support of, or in opposition to, using the rate base method for the prescribed assets for the test period (see section 5.3.2 above).

As noted in the preceding section of this decision, OPG submitted that the reference in Section 6(2)7 to "return on rate base" shows that the government intended OPG to use the rate base method to calculate balances in the Section 5.1 and 5.2 deferral accounts. OPG argued that:

> There would be absolutely no need for, or even meaning to, this provision if it had not been the LGIC's [Lieutenant Governor in Council] intention that payment amounts reflect the revenue requirement impact of the rate base approach to recovering the cost of OPG's nuclear waste management obligations.[69]

Board staff submitted that Section 6(2)7 of the regulation requires the Board to accept the amounts in the Section 5.1 deferral account.

CME disagreed with the staff position because it "implies that the Board cannot assess the appropriateness of the method OPG has used to calculate the amount of the revenue requirement impact to be recorded in the Deferral Account."[70] In CME's view, the phrase "to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded" in Section 6(2)7 means that the account balance must be determined in accordance with a method that the Board has determined is appropriate.

CME argued that no amounts related to the increase in the Bruce nuclear liabilities should be included in the Section 5.1 deferral account.

SEC's submissions on the nuclear deferral accounts related mainly to the Section 5.2 account, which relates to changes in nuclear liabilities that occur after the date of the Board's first order. As noted in section 5.3.1 above, SEC concluded that the references to "return on rate base" and the other three items in Section 6(2)7 of the regulation are problematic because OPG's audited financial statements either do not contain such items or because a literal interpretation of the item leads to an absurd result. SEC submitted that an appropriate interpretation of "return on rate base" as it relates to the

[69] OPG Argument-in-Chief, page 84.

[70] CME Argument, paragraph 42.

Section 5.2 deferral account is that it is intended to require OPG to record an amount reflective of the time value of money.

Board Findings

The two issues with respect to the nuclear liability deferral accounts are: (i) Does the regulation require OPG to use the rate base method to calculate the balances in the accounts?, and (ii) Are the deferral accounts solely to record costs of nuclear liabilities of the prescribed facilities, or should costs related to the Bruce stations also be included? Reaching answers to these questions required the Board to interpret the meaning of the term “return on rate base” in Section 6(2)7.

OPG’s position is that the inclusion of the term “return on rate base” in Section 6(2)7 means the LGIC must have intended that OPG use, and the Board adopt, the rate base method. The Board does not agree with OPG’s position.

On the surface, the instructions in Section 6(2)7 seem to make no sense. The section contemplates that the amount of “return on rate base” and the amounts of other items listed in the section are the amounts “as reflected in” OPG’s December 31, 2007 financial statements. As SEC points out, there is no item “return on rate base” in OPG’s financial statements. Thus, a literal interpretation of Section 6(2)7 would lead to no recovery whatsoever for amounts in the Section 5.1 deferral account that OPG labels as “return on rate base”.

Another difficultly in interpreting Section 6(2)7’s reference to “return on rate base” is that, by definition, the additional ARC that arises when a nuclear liability is increased is not included in rate base at the time the ARC is recorded. If it were in rate base at that time, a deferral account would be unnecessary. The additional ARC will not be included in rate base until the Board resets the payment amounts in a subsequent hearing. Once again, a literal application of the “return on rate base’ in Section 6(2)7 would lead to a zero return for OPG because there would be no amount in rate base on which a return could be calculated.

The Board has adopted an approach to Section 6(2)7 that is consistent with the purpose of the Section 5.1 and 5.2 deferral accounts. In the Board’s view, the purpose of those accounts is to capture revenue requirement impacts of certain events that occur after payment amounts for OPG have been set. The Section 5.1 account was for nuclear liability increases that occurred after the effective date of the payment amounts set by the Province but before the effective date of the Board's first order. Section 5.2 is for liability changes that occur after the Board has set payment amounts for a particular period. It is reasonable to conclude that the intent of the deferral accounts is to ensure OPG is "kept whole" for the cost consequences of liability increases that were not, and could not have been, considered when payment amounts were set.

In the Board's view, the accounts should operate to ensure OPG is in no worse, or better, a financial position than it would have been had the Province (in the case of the Section 5.1 account) or the Board (in the case of the Section 5.2 account) been aware of the future increase in the liabilities at the time it set the payment amounts. Had there been knowledge of a pending increase in the nuclear liabilities, presumably the approved revenue requirement would have included some additional revenue to offset the known costs of liability increases that were going to happen during the test period.

Having concluded that the intent of O. Reg. 53/05 with respect to the deferral accounts was to ensure OPG is "kept whole," the Board also concluded that Section 6(2)7 does not specify any particular method for calculating the amounts that would keep OPG whole. In the Board's view, the method that should be used to determine balances in the deferral accounts should be the same as the method used by the Board (or for the initial period, the Province) to include the cost of nuclear liabilities built into the existing payment amounts.

Under this interpretation of Section 6(2)7, what does the phrase "as reflected in the audited financial statements" mean as it relates to "return on rate base"? In the Board's view, that phrase means that, in respect of new liabilities, OPG should be allowed to record in the deferral account the "return" that it is inherent in the existing payment amounts that are recognized as revenue in OPG's financial statements.

To assess the appropriateness of the balance in the Section 5.1 deferral account, it is necessary determine how the cost of nuclear liabilities was included in the initial payment amounts. OPG's evidence was that those payment amounts were determined by the Province using: the rate base method for both the prescribed assets and the Bruce stations; a 55% debt-45% equity capital structure; a debt rate of 6%; and, a return on equity of 5%.

As SEC pointed out, it is not entirely clear how the initial payment amounts were set by the Province. Based on the evidence in this proceeding, except for the inclusion of the

Bruce stations, the Board accepts that the Province used the approach described by OPG. In Chapter 6 of this decision, the Board concludes that the record is less clear as to whether the Province adopted the rate base method for the Bruce nuclear liabilities when it set the initial payments.

Notwithstanding the lack of clarity about how the Bruce stations were handled in the initial payment amounts, the Board approves the balance in the Section 5.1 deferral account, including the accrual of a 5.55% return on the incremental unamortized ARC related to Pickering, Darlington and Bruce nuclear stations. The Board notes that 63% of the increase in nuclear liabilities that occurred at the end of 2006 related to the Bruce stations. That increase occurred before the amendment of O. Reg. 53/05 to add Section 5.1, so the government presumably would have been aware of the magnitude of the increase in the Bruce liabilities. If the government intended to restrict the Section 5.1 deferral account to just Pickering and Darlington, and exclude the substantial increase in the Bruce liabilities, the regulation would have stated that.

As for the Section 5.2 deferral account, the Board is taking a different approach. First, the account should be restricted to the revenue requirement impact of changes in the nuclear liabilities for Pickering and Darlington. As discussed in Chapter 6, the Board has concluded that the terms “revenue requirement” and “return on rate base” are not applicable to OPG’s unregulated Bruce activities. Second, the “return on rate base” component should be calculated in accordance with the method outlined in section 5.3.2 of this decision concerning the calculation of the revenue requirement impact of nuclear liabilities for the test period. This is consistent with the Board’s interpretation of the regulation that the deferral accounts are intended to keep OPG whole and that entries to the account should be made using the same regulatory structure as was used to set the payment amounts. The practical consequence of this approach is that the “return on rate base” element of the Section 5.2 deferral account will be determined using the discount rate that OPG used to calculate the new increased liabilities until such time as OPG begins to fund the additional liability.

6 BRUCE NUCLEAR STATIONS: OPG's REVENUES AND COSTS

OPG owns the Bruce A and Bruce B nuclear generating stations located on the shore of Lake Huron near Kincardine, Ontario. Currently, six units are operational and the two other units are being refurbished. When all eight units are operational, the aggregate capacity of the stations will be over 6,200 MW.

In 2001, OPG leased the stations to Bruce Power L.P., a partnership not related to OPG.[71] The lease runs until 2018 and Bruce Power has an option to renew the lease for a further 25 years. Bruce Power operates the stations and supplies energy to the IESO-administered electricity market.

OPG receives lease payments from Bruce Power as well as revenues for providing engineering and other services to the partnership. OPG retained responsibility for the decommissioning and nuclear waste management liabilities related to Bruce A and Bruce B.

The Bruce nuclear generating stations are not prescribed generation facilities under O. Reg. 53/05. Bruce Power holds a generation license issued by the Board. The Board, however, has no authority to set or review the terms of the lease between OPG and Bruce Power and it does not regulate the prices for engineering and other services provided to Bruce Power by OPG.

Despite the fact that the Bruce nuclear stations are not prescribed generation facilities, OPG's revenues and costs related to the Bruce lease were major issues in this proceeding.

O. Reg. 53/05 requires the Board to include OPG's revenues and costs for Bruce in the determination of the payment amounts for the Pickering and Darlington nuclear stations. OPG forecast net Bruce revenues for the test period of $134.4 million, which OPG deducted from the nuclear revenue requirement to determine the payment amounts for Pickering and Darlington. This chapter addresses the question of whether OPG has

[71] Bruce Power L.P. is a partnership among Cameco Corporation, TransCanada Corporation, BPC Generation Infrastructure Trust, a trust established by the Ontario Municipal Employees Retirement System, the Power Workers' Union and The Society of Energy Professionals.

used an appropriate method to calculate the revenues and costs for the test period for Bruce.

OPG proposed to include certain 2007 costs related to the Bruce nuclear liabilities in the deferral account established by Section 5.1 of the regulation. That issue is addressed in Chapter 5 of this decision.

Paragraphs 9 and 10 of Section 6(2) of O. Reg. 53/05 state:

> 9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.
>
> 10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2 [Pickering A, Pickering B, and Darlington].

OPG proposed that the test period revenue requirement for Pickering A, Pickering B and Darlington be reduced by approximately $134 million in respect of net revenues related to Bruce. OPG's forecast test period revenues and costs for the Bruce stations are shown in Table 6-1, together with actual 2007 amounts calculated on a comparable basis.

Some of the forecast revenues and costs included in OPG's application in respect of Bruce were determined in accordance with Canadian GAAP applicable to a non-regulated entity. OPG calculated certain other costs and revenues using other accounting bases. The significant non-GAAP policies used by OPG were:

- OPG used a cash basis of accounting for revenue from the Bruce lease. Had OPG computed the revenue in accordance with GAAP, the lease revenue for the test period would have been approximately $30 million more than shown in OPG's application.
- OPG's calculation of the net revenues related to Bruce omits both the accretion expense on the fixed asset removal and nuclear waste management liabilities related to the Bruce stations and the earnings on the related segregated funds.

Table 6-1: OPG's Calculation of Excess Bruce Revenues

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenue:			
Lease with Bruce Power	$ 252.8	$ 257.4	$ 263.2
Services revenue	48.1	19.7	12.6
Total revenue	**300.9**	**277.1**	**275.8**
Costs:			
Depreciation	120.6	77.5	66.7
Property tax	13.8	15.2	15.5
Capital tax	2.8	2.6	2.5
Used fuel storage and management	13.3	14.1	14.8
Interest	37.6	28.4	27.6
Income tax	-	-	-
Return on equity	27.7	70.2	66.1
Total costs	**215.8**	**208.0**	**193.2**
Revenue less costs	**$ 85.1**	**$ 69.1**	**$ 82.6**
9/12's of 2008 net revenue			51.8
Offset to test period revenue requirement			**$ 134.4**

Sources: Ex. G2-2-1, Tables 1 and 3; Ex. K1-1-1, Tables 1 and 2.

- OPG has proposed to use the same "rate base method" to calculate the cost of the Bruce nuclear liabilities as it proposed to use for the nuclear liabilities of the prescribed facilities. Under that approach, the net book value of OPG's fixed assets related to the Bruce stations was considered to be part of the rate base on which OPG calculated a return on capital. Table 6-1 shows that OPG has included a return on equity as a cost of the Bruce lease. That cost would not be included in an income statement prepared in accordance with GAAP. The return was calculated using the same deemed capital structure (42.5% debt and 57.5% equity) and 10.5% ROE that were proposed by OPG for the prescribed facilities.
- The interest expense in Table 6-1 has also been calculated using the rate base method, which results in the inclusion of deemed interest expense, which is greater than the amount that would be recorded under GAAP.
- OPG's calculation of costs does not include any income tax provision.

The GAAP approach to calculating OPG's revenues less costs for the Bruce stations would result in a substantially higher net revenue amount than would OPG's proposed approach. The pre-tax amounts determined under the two different approaches are reconciled in Table 6-2.

Table 6-2: Bruce Revenues and Costs: Reconciliation of OPG's Calculation with GAAP

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenues less costs per OPG (Table 6-1)	**$ 85.1**	**$ 69.1**	**$ 82.6**
Add:			
Adjust lease revenue to accrual accounting	20.7	20.7	15.5
Eliminate deemed interest expense	37.6	28.4	27.6
Eliminate return on equity	27.7	70.2	66.1
Eliminate deemed capital taxes	2.8	2.6	2.5
Expenses recorded in nuclear deferral account	3.5	-	-
Earnings on segregated funds	194.2	234.9	262.0
Deduct:			
Accretion on nuclear liabilities	(207.2)	(255.9)	(282.0)
Interest on actual debt	(20.3)	(21.2)	(21.1)
Actual capital taxes	(1.1)	(4.4)	(3.6)
GAAP income before tax	**$ 143.0**	**$ 144.4**	**$ 149.6**

Source: Ex. J8.1, page 6.

OPG noted that Section 6(2)9 of O. Reg. 53/05 requires the Board to ensure OPG recovers "all the costs it incurs" with respect to the Bruce stations. OPG argued that it is clear that a return on equity in respect of OPG's investment in the Bruce stations is a cost incurred by OPG. OPG submitted that Section 6(2)8 of the regulation, which requires the Board to ensure OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan, is not restricted to nuclear liabilities related to the prescribed facilities. Rather, OPG contends that Section 6(2)8 is of general application and must be applicable to the Bruce liabilities because those liabilities arise from OPG's approved reference plan under ONFA. OPG submitted: "Nothing about the legislative purpose of O. Reg. 53/05 demands excluding Bruce nuclear waste and decommissioning liabilities from the determination of OPG's revenue requirement."[72]

[72] OPG Reply Argument, page 115.

OPG claimed that its proposed treatment of Bruce lease costs, including the use of the rate base method, is the same as that recommended by CIBC World Markets in its December 2004 report (the "CIBC report"). That report stated:

> Based on CIBC World Markets' analysis and the objectives of the Province previously stated, we believe that the revenues from the Bruce lease, net of OPG's costs for these assets, should be included as part of the regulated rate base, which has the effect of lowering the regulated rate for OPG's nuclear assets.[73]

OPG also claimed that its proposed treatment is the same as the treatment used by the Province to set the existing payment amounts. OPG submitted that the policy issue of how much of the Bruce lease revenues the government intended to be used to offset the revenue requirement for Pickering and Darlington is made clear from the government's decision to include the Bruce fixed assets in OPG's rate base during the interim period. OPG argued that this interim period treatment is "strong evidence that the cost arising from the 'rate base' approach to recovering nuclear waste management was intended to qualify under Section 6(2)9 of O. Reg. 53/05 as a 'cost' which OPG 'incurs' with respect to the Bruce stations."[74]

OPG also provided its opinion on what the Province knew, and what the Province assumed, when it set the current payment amounts:

> …it was well known to the Province that the interim rates that it approved for the 2005 to 2008 period reflected costs associated with Bruce A and B nuclear liabilities. Not only did the province assume that "costs incurred" with respect to the Bruce facilities included nuclear liabilities associated with the Bruce facilities, it also assumed, for purposes of interim rates, that the proxy for the recovery of that cost was the return on the value of the Bruce NGS fixed asset, i.e., the "rate base method." … [T]he fact that interim rates employed the rate base method for the recovery of nuclear liability costs and the fact that the Province was aware, before the application was made, of what OPG was seeking in this case, while not binding on the OEB after April 1, 2008, are powerful evidence of surrounding circumstances, which must be considered in determining the meaning and intent of sections 6 (2) 7 to 10 of the Regulation.[75]

OPG asserted that "common sense" and "common regulatory practice" support a conclusion that return on equity is a "cost" under Section 6(2)9 of the regulation.

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[73] CIBC Report, page 20.

[74] OPG Argument-in-Chief, page 87.

[75] OPG Reply Argument, pages 113 and 114.

Board staff took the position that Section 6(2)8 of the regulation, which deals with recovery of the revenue requirement impact of OPG's nuclear liabilities, is applicable only to the cost of the nuclear liabilities related to the prescribed nuclear facilities, Pickering and Darlington. Board staff submitted that the relevant sections of the regulation with respect to the OPG's test period costs for Bruce are Sections 6(2)9 and 6(2)5. Staff submitted that it is appropriate for the Board to determine the Bruce costs incurred and revenues earned by OPG in the test period:

> … by giving those terms ("cost" and "revenues") the meaning they would ordinarily have in the context of rate-setting applications (including those based on a cost-of-service application). In other words, the Board should use generally accepted accounting principles applicable in a rate setting environment to determine what constitutes a cost with respect to Bruce Facilities.[76]

CCC submitted that the Board should exclude a return on Bruce assets when calculating costs recoverable under Section 6(2)9 of the regulation. CCC contended that O. Reg. 53/05 does not guarantee OPG a return on the Bruce assets.

CME argued that the only reasonable interpretation of Sections 6(2)9 and 6(2)10 of the regulation is that "nuclear liability costs attributable to Bruce are only recoverable to the extent that Bruce costs exceed Bruce revenues."[77] CME argued that the total amount of the "rate base method" elements of OPG's calculation of Bruce costs – deemed interest expense, return on equity, and deemed capital taxes – should not be recovered. CME calculated that by including those items as costs, OPG has understated the excess of its Bruce revenues over costs for the test period by $171 million.

CME submitted that whether the word "costs" in Sections 6(2)9 and 6(2)10 should be construed to include a return on Bruce assets is a question for the Board to resolve. In CME's view, the Board is not bound by the method used to set initial rates. CME contended that there is nothing in the regulation that supports OPG's contention that "costs" must include a profit or return. It also submitted that OPG's interpretation of the regulation would result in OPG earning a guaranteed return on its Bruce investment, a result CME argued was not intended by O. Reg. 53/05.
VECC adopted CME's submission on the proper interpretation of the regulation with respect to the Bruce assets.

[76] Board Staff Argument, page 10.

[77] CME Argument, page 16.

In its reply, OPG stated that CME, VECC and Board staff argued that "OPG has no right to any recovery of the cost of nuclear liabilities, however calculated, with respect to the Bruce facilities."[78] OPG submitted that those arguments are based on a "profoundly and patently unreasonable misinterpretation of the Regulation which, if adopted, would constitute grounds for reversal on a matter of law".[79]

OPG objected to CME's submission that nuclear liability costs for the Bruce stations are only recoverable to the extent that Bruce costs exceed Bruce revenues. OPG submitted that Sections 6(2)9 and 6(2)10 "can only be read to mean that any credit to the revenue requirement arising from the Bruce facilities is after recovery of *all costs incurred* with respect to those facilities."[80] (emphasis in original)

Board Findings

The Board agrees with OPG that O. Reg. 53/05 requires the Board to ensure that OPG recovers all of its costs with respect to Bruce. The language in Section 6(2)9 ("all the costs it incurs") is clear and unambiguous.

The Board also finds that costs related to the Bruce nuclear liabilities are costs for the purposes of Sections 6(2)9 and 6(2)10. As owner of the Bruce stations, OPG has the obligation to manage nuclear waste and to decommission the plants, and that obligation gives rise to substantial costs. Although there are different views about how those costs should be measured, there was no evidence in this proceeding that OPG will not be incurring costs during the test period in respect to the Bruce nuclear liabilities.

The Board also finds that any reduction in the payment amounts for Pickering and Darlington pursuant to Section 6(2)10 should take into account the amount of the Bruce costs required to be recovered under Section 6(2)9. The Board does not agree with CME's interpretation that Bruce nuclear liability costs are only recoverable to the extent that Bruce costs exceed Bruce revenues. As the Board understands CME's position, no costs related to the Bruce nuclear liabilities are recoverable by OPG whenever Bruce revenues exceed Bruce costs. In the Board's view, Section 6(2)10 does not in any way limit the Section 6(2)9 requirement that the Board ensure recovery of all costs incurred.

[78] OPG Reply Argument, page 112.

[79] Ibid.

[80] OPG Reply Argument, page 116.

The remaining issue is determining how the test period revenues and costs related to the Bruce stations should be measured. As noted earlier in this chapter of the decision, OPG has computed some test period revenues and costs for Bruce in accordance with GAAP but, in other cases, has used non-GAAP measures or included items that would not qualify as costs under GAAP.

In making its determination on how OPG's Bruce-related revenues and costs should be calculated for purposes of Sections 6(2)9 and 6(2)10 of the regulation, the Board first considered why the Province directed that any revenues or expenses related to Bruce should be included in the calculation of the payment amounts for Pickering and Darlington. In the Board's experience, it is unusual to decrease (or increase) rates for a regulated service by using the profits (or losses) of a separate, unregulated business that happens to be owned by the same entity.

OPG's involvement with the Bruce stations is quite different from its involvement with Pickering and Darlington. For example, the Board (and previously the Province) regulates the prices for energy production from the prescribed facilities. In contrast, the lease payments charged by OPG to Bruce Power (and the prices charged for engineering and other services) are the result of a commercial contract; they are not regulated by the Board or any other body. In addition, OPG operates the Pickering and Darlington plants and is responsible for offering the energy produced into the IESO electricity market. The Bruce plants are operated by Bruce Power, not OPG.

There was very little in the evidence in this hearing that explained why the regulation requires the Board to consider OPG's Bruce-related revenues and costs. The Bruce stations were not identified in the August 2004 draft regulation and consultation paper that was issued for public comment by the Ministry of Energy.[81] The first references to using Bruce revenues to reduce the payment amounts for the prescribed facilities appear to be in the December 2004 CIBC report. The executive summary of that report states:

> **OPG's Regulatory Construct**: We took as the starting point for OPG's regulatory construct the draft regulation and consultation paper for the initial rates for OPG's price regulated plants issued by the Ministry of Energy in August 2004. Following discussions with officials at the OFA and Energy, and based on its analysis, we provided several additional recommendations or variances from the draft consultation regulation and paper, as follows:

[81] The draft regulation and consultation paper are reproduced in Appendix J to the CIBC report.

- Use as an offset to OPG's regulated revenue requirement, OPG's revenues from the lease of its Bruce assets to Bruce Power, net of OPG's costs, which reduces the regulated rate.[82]

The CIBC report also notes that: "Whether these OPG assets are included or excluded under the regulation of OPG is a governmental policy issue rather than one that can be evaluated from regulatory precedents."[83]

Although not stated explicitly in any document issued by the Province to the Board's knowledge, it appears that the inclusion of the Bruce net revenues is essentially a mitigation measure. This view is supported by testimony of an OPG witness, who agreed that the inclusion of Bruce revenues and costs in the calculation of the payment amounts was intended to provide shelter against higher payments on the prescribed assets.[84]

In the Board's view, the fact that the net revenues related to OPG's unregulated Bruce lease are intended to mitigate the payment amounts for Pickering and Darlington does not lead to a conclusion that the Province must have intended that the Bruce revenues and costs be calculated as if OPG's investment in Bruce were subject to regulation.

Further, the Board finds that the Bruce net revenues, as a mitigation measure, do not form part of OPG's revenue requirement for the prescribed assets. Rather, the Board concludes that the regulation requires net revenues be used to reduce the payment amounts that would otherwise be set based on the revenue requirement for the prescribed assets. In the Board's view, "revenue requirement" is a concept that is applicable only to rate-regulated activities.

OPG advanced two arguments in support of its position that the rate base method should be used when calculating Bruce test period costs.

First, OPG has submitted that its use of the rate base method to calculate Bruce test period costs is consistent with the recommendations in the December 2004 CIBC report.

[82] CIBC report, page 2.

[83] CIBC World Markets report, page 20.

[84] Transcript, Volume 7, page 36.

It is true, as OPG notes, that page 20 of the CIBC report mentions "regulated rate base" when it refers to the Bruce stations. The Board is not convinced, however, that those words refer to OPG's "rate base method" because the CIBC report uses different, and inconsistent, terminology when it discusses CIBC's recommended treatment for the Bruce lease. For example, the CIBC report refers, in one place, to including "revenues from the lease of Bruce" in rate base, a concept that is difficult to understand because assets, not revenues, are included in rate base.[85] The Board also notes that other parts of the CIBC report that discuss the Bruce lease do not mention rate base at all but refer simply to using revenues from the Bruce lease as an offset to "OPG's regulated revenue requirement"[86] or to including "lease cash flows from Bruce Power."[87]

The CIBC report also states that rate base "reflects a company's investment in assets related to its regulated business,"[88] which, in OPG's case, does not include its investment in Bruce, an unregulated business.

In short, after reviewing the CIBC report to determine if it recommended the rate base method for calculating the Bruce test period costs, the Board is of the view that it did not.

OPG's second argument was that when the Province set the initial payment amounts for the prescribed facilities, it deducted net revenues for the Bruce lease that had been calculated using the rate base method.

Aside from OPG's claim, no evidence has been filed with this Board that sets out how the initial payments were calculated by the Province. The Board was unable to determine what was included in the rate base amount shown in the CIBC report; in any event, the initial payment amounts struck by the Province were different than the amounts set out in the CIBC report. The Board notes that a February 23, 2005 presentation on the payment amounts by Ministry of Energy officials indicated only that: "Earnings from the Bruce Nuclear Lease incorporated [sic] in the setting of the regulated

[85] CIBC Report, page 20.

[86] CIBC Report, pages 2, 27 and 34.

[87] CIBC Report, page 26.

[88] CIBC Report, page 10.

price of nuclear."[89] The term "earnings" does not suggest any particular basis of calculation.

The Board also notes that the "rate base" amount included in OPG's application is restricted to assets related to the prescribed facilities. No amounts related to the Bruce stations are included.

The Board concludes that the evidence is unclear as to whether the Province used the rate base method to calculate the net revenues for the Bruce lease when it set the initial payment amounts. Even if the rate base method were used to set the initial payments, however, the Board concludes it is not bound to continue that approach after April 1, 2008.

The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would not be a reasonable interpretation of Sections 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use. Had the Province intended the Board to determine revenues and costs related to Bruce in accordance with principles applicable to a regulated business, the regulation would have so stated.

OPG proposed to calculate Bruce lease revenue for the test period in accordance with a policy that would not be acceptable for an unregulated commercial entity. The company's rationale for following a cash basis of accounting for lease revenue, rather than a GAAP basis, is not clear to the Board.

OPG took the position that O. Reg. 53/05 requires the Board to accept OPG's cash basis accounting policy for Bruce lease revenue. Section 6(2)5 of the regulation requires the Board to accept certain amounts that are set out in OPG's 2007 audited financial statements, including "OPG's revenues earned with respect to any lease of the Bruce Nuclear Generating Stations." Section 6(2)6 stipulates that section 6(2)5 applies to "values relating to … the revenue requirement impact of accounting and tax policy decisions." OPG claimed that Section 6(2)6 obligates the Board to accept the

[89] Ministry of Energy, "Technical Briefing on OPG Pricing Announcement," February 23, 2005, page 8. [Exhibit J1.4]

accounting policy that was used by OPG to record lease revenue in 2007 when the Board determines OPG's Bruce lease revenue for the test period.

The Board does not accept that it is required to use the cash basis of accounting to calculate the test period revenues for the Bruce lease. In the Board's view, section 6(2)5 obligates the Board to accept the book values of assets and liabilities as at December 31, 2007 and requires the Board to accept the accounting policies that were used to compute those book values. Bruce lease revenue for the test period, an <u>income statement</u> amount for a period <u>subsequent</u> to 2007, is clearly not an asset or liability that is set out in OPG's 2007 financial statements. Those financial statements show lease revenue for 2007; the financial statements are not projections or forecasts of future revenues.

The Board will require that Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses. The Board's rationale is the same as its rationale for requiring that the cost of the Bruce nuclear liabilities be computed in accordance with GAAP – it is not reasonable to interpret the regulation to find that OPG can calculate revenues from an unregulated activity using an accounting policy that an unregulated company would not be permitted to use.

The Board directs OPG to revise its calculation of the net test period revenues related to Bruce as follows:

1. The rate base method should not be used to calculate OPG's costs in respect of Bruce. That means that "costs" should exclude the return on equity and deemed interest expense that flow from the rate base method.
2. OPG should base its calculation of costs on GAAP. The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs.
3. OPG should calculate lease revenue in accordance with GAAP.
4. OPG should include an income tax (PILS) provision, calculated in accordance with GAAP, in its computation of Bruce costs. OPG proposed to exclude income taxes on the basis that there are tax loss carry forwards available to the regulated businesses. As OPG's Bruce investment is not regulated by the Board,

the Board sees no basis for omitting a tax provision in the calculation of Bruce costs.

The net effect of these findings is that any profit (or loss) in respect of OPG's Bruce lease, calculated in accordance with GAAP, will increase (or decrease) the payment amounts for the prescribed assets. Under this approach, the payment amounts for the prescribed assets are likely to be lower in all cases than the payment amounts calculated under OPG's interpretation of O. Reg. 53/05. When OPG earns a profit (measured in accordance with GAAP) on its Bruce activities, the Board's approach calls for all of that profit to be used to reduce the payment amounts for Pickering and Darlington. OPG's approach would result in a smaller offset to the payment amounts because OPG would include a regulated return on its Bruce investment as a cost. If OPG were to incur a loss on its Bruce activities, which could happen if there are significant increases in the Bruce nuclear liabilities in the future, that loss would increase the payment amounts for the prescribed assets under the Board's approach. OPG's approach likely would result in a greater increase to the payment amounts, again because OPG would include a regulated return on its Bruce investment as a cost.

Under OPG's approach, as CCC and CME pointed out, electricity consumers would in effect be guaranteeing that OPG earns a return on its Bruce fixed assets. The Board has no evidence that supports such an approach, and believes the effect of such an approach on the nuclear payment amounts would not be reasonable. Under O. Reg. 53/05, electricity consumers, not OPG, are exposed to the risk that they will have to absorb, through higher payment amounts for the prescribed assets, any losses related to Bruce in the future. It is, therefore, appropriate that when OPG earns profits on its Bruce activities that consumers receive the full benefit of those profits, without deduction of a regulated return as proposed by OPG.

Calculating revenues and costs in accordance with GAAP will result in a higher excess of Bruce-related revenues over costs for the test period than the $134.4 million proposed by OPG. The Board estimates that the excess revenues under the GAAP approach are approximately $175 million (based on the GAAP pre-tax income amounts in Table 2, adjusted to reflect a 21-month test period, and tax rates of 31.5% in 2008 and 31.0% in 2009 as specified in OPG's application). The precise amounts will be determined by OPG and filed with the Board.

OPG did not apply for a variance account for test period revenues and costs in respect of the Bruce stations. Section 6(2)9 of the regulation requires the Board to ensure that OPG recovers all of its costs related to the Bruce stations. In the Board's view, this section obligates the Board to ensure OPG recovers its actual, not forecast, costs related to Bruce. Section 6(2)10 requires that the excess of revenues earned in respect of the Bruce stations over the costs incurred by OPG should reduce the payment amounts for the prescribed facilities. In the Board's view, this section obligates the Board to ensure that the actual, not forecast, excess of revenues over costs is used to offset the payment amounts for Pickering and Darlington. Accordingly, the Board directs OPG to establish a variance account to capture differences between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG's actual revenues and costs in respect of Bruce. The cost impact of any changes in nuclear liabilities related to the Bruce stations should be recorded in this account, not the nuclear liabilities deferral account required by Section 5.2 of the regulation.

7 DEFERRAL AND VARIANCE ACCOUNTS

O. Reg. 53/05 authorized OPG to establish several deferral and variance accounts to record amounts for the period up to the effective date of the Board's first order under Section 78.1 of the *OEB Act*, which will be April 1, 2008. OPG has applied for clearance of deferral and variance accounts based on December 31, 2007 balances, which are set out in OPG's most recent audited financial statements. OPG indicated it will continue to record amounts in these accounts during the three-month period ending March 31, 2008 and will bring those balances forward for disposition in its next application.

Existing nuclear deferral and variance accounts are addressed in section 7.1. Existing hydroelectric accounts are covered in section 7.2.

OPG also applied for several new deferral and variance accounts and intervenors also recommended some new accounts. Proposed new accounts are addressed in section 7.3. The rate to be used to accrue interest on the account balances is covered in section 7.4.

7.1 Existing Nuclear Accounts

Table 7-1 sets out the nuclear deferral account balances at December 31, 2007. OPG proposed to recover $128.1 million of the balance during the 21-month test period via a nuclear rate rider of $1.45 per MWh.

Table 7-1: Nuclear Deferral and Variance Accounts, December 31, 2007

Account	Amount *$ millions*	Reg. 53/05 Section	Recovery Period	
			OPG Proposal	Maximum per Reg. 53/05
Pickering A return to service	**$ 183.8**	5 (4)	11.75 years	15 years
Nuclear liability	**130.5**	5.1	2.75 years	3 years
Nuclear development - New facilities	**11.7**	5.3	2.75 years	3 years
Nuclear development - Capacity refurbishments	**16.2**	6 (2) 4	2.75 years	n/a
Ancillary services	**(1.7)**	5 (1) (c)	2.75 years	3 years
Transmission outages and restrictions	**1.6**	5 (1) (e)	2.75 years	3 years
Total	**$ 342.1**			

Sources: Ex. J1-2-1, Table 4; O. Reg. 53/05.

7.1.1 Pickering A return to service (PARTS)

This deferral account records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station. Section 5(4) of O. Reg. 53/05, as amended in 2007, authorized OPG to include costs related to the Pickering units that OPG determined will not return to service, being Units 2 and 3. The regulation also permits OPG to include interest on the balance at an annual rate of 6%.

Section 6(2)3 of the regulation requires the Board to ensure OPG recovers the balance in this account on a straight-line basis over a period not to exceed 15 years.

OPG recorded non-capital costs in this account totalling $271 million (mostly related to Pickering A Unit 1). The company commenced amortization of the costs in 2005. The December 31, 2007 balance of $183.8 million is net of the accumulated amortization and includes interest.

Section 6(2)(5) of O. Reg. 53/05 requires that, in making its first order under section 78.1 of the *OEB Act*, the Board shall accept amounts as set out in OPG's most recently audited financial statements, which are as at and for the year ended December 31, 2007. The PARTS deferral account balance is included in those financial statements.

OPG concluded that the long recovery period of 11 years and nine months is appropriate because the costs were incurred to extend the service life of Pickering A. Most of the costs related to extending the service life of Unit 1, which OPG estimates has an “end of life” date of 2021. The proposed recovery during the test period is $27.4 million.

Intervenors and Board staff did not contest the balance in the PARTS account or the proposed recovery period.

Board Findings

OPG’s evidence was that the balance in the PARTS account has been recorded accurately. None of the parties in this proceeding objected. The account balance is set out in OPG’s audited 2007 financial statements and O. Reg. 53/05 requires the Board to accept that amount.

OPG has proposed a lengthy recovery period on the basis that the account is associated with a long-term asset, Pickering A, that is expected to generate electricity over the period to 2021.

The Board does not find this rationale convincing. Although the costs may be “associated” with the Pickering A return to service project, the fact remains that they are non-capital costs that, absent the regulation, would not have been capitalized and amortized under generally accepted accounting principles. In the Board’s view, there is no compelling rationale for linking recovery of the costs to the service life of Pickering A.

Under OPG’s proposal, the recovery of the balance in the PARTS account during the test period would be $27 million. This is substantially lower than the test-period recovery of the nuclear liability deferral account of $83 million, which is being recovered over a three-year period and is addressed later in this chapter. The Board concludes that it is appropriate to recover the PARTS account balance over a shorter period than that proposed by OPG. The Board approves recovery over the period April 1, 2008 to December 31, 2011.

7.1.2 Nuclear liability deferral account

O. Reg. 53/05 was amended in 2007 to require OPG to establish a deferral account to capture certain amounts related to changes in nuclear liabilities that occurred after April 1, 2005 and before the effective date of the Board's first order. The regulation requires the Board to ensure that the balance in this account is recovered on a straight-line basis over a period not to exceed three years. The regulation also requires OPG to accrue interest on the account balance at an annual rate of 6 per cent.

On December 31, 2006, OPG recorded an increase of $1,386 million in its nuclear decommissioning and nuclear waste management liabilities. In accordance with Canadian generally accepted accounting principles, OPG also increased the net book values of the relevant nuclear stations by an equal amount. The increases in the net book values at the end of 2006 for these asset retirement costs, or ARC, were $878 million for the Bruce stations and $508 million for the Pickering and Darlington stations.

The balance in the nuclear liability deferral account as at December 31, 2007 was $130.5 million. The components of the balance are shown in Table 5-6 in Chapter 5.

Chapter 5 of this decision (section 5.3.3) sets out the submissions by OPG and intervenors, and Board findings, on the two significant issues related to this account balance: OPG's use of the rate base method to calculate the account balance, and the inclusion of costs related to the increase in the Bruce nuclear liabilities. Except for those two issues, intervenors did not comment on OPG's calculation of the other components of the account balance.

Board Findings

In section 5.3.3 of this decision, the Board found that it would accept including in the deferral account a return of 5.55% on the average unamortized ARC related to the increase in nuclear liabilities. The Board also found that it would accept the inclusion of costs related to the increase in the Bruce nuclear liabilities in this account. There were no questions raised by any party with respect to the entries in the account for depreciation and the other expenses.

The Board accepts disposition of the balance in this account over the period proposed by OPG.

7.1.3 Nuclear development – New facilities

On June 16, 2006, the Minister of Energy directed OPG to begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. Section 5.3 of O. Reg. 53/05 authorizes a deferral account to record costs incurred and firm financial commitments made on or after June 13, 2006 in the course of carrying out these activities, for the period up to the effective date of the Board 's first order. The regulation permits OPG to include interest on the balance at an annual rate of 6%.

The new nuclear facilities deferral account balance is included in OPG's audited 2007 financial statements. The balance at December 31, 2007 is made up of costs to explore development of new capacity at the Darlington site plus interest.

Section 6(2)7.1 of the regulation requires the Board to ensure OPG recovers the balance in this account on a straight-line basis over a period not to exceed three years. OPG has proposed that recovery take place over two years and nine months, being the 21-month test period plus one additional year.

Intervenors and Board staff did not contest the balance in this account or the proposed recovery period.

Board Findings
OPG's evidence was that the balance in this account has been recorded accurately and no party disputed that. The balance is set out in OPG's audited 2007 financial statements. The Board approves recovery of the balance as proposed by OPG.

7.1.4 Nuclear development – Capacity refurbishments

The June 16, 2006 directive from the Minister of Energy on new nuclear facilities also required OPG to begin feasibility studies on refurbishing its existing nuclear units. The Minister directed OPG to begin an environmental assessment on the refurbishment of the four units at Pickering B.

OPG has deferred $16.2 million at December 31, 2007, being non-capital costs related to exploring refurbishment of Pickering and Darlington. OPG stated that these expenditures were not included in forecast information provided to the Province when the existing payment amounts were set in 2005.

O. Reg. 53/05 does not establish deferral or variance accounts for pre-April 1, 2008 spending on assessing the feasibility of refurbishing Pickering or Darlington. OPG supported the deferral and recovery of these expenditures by reference to Section 6(2)4 of O. Reg. 53/05, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2 [the prescribed generation facilities], including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

OPG also submitted that the Board is obligated to approve recovery of the account because the balance is set out in OPG's 2007 audited financial statements, and because the costs incurred were within approved project budgets.

None of the intervenors objected to OPG's recovery of this balance.

Board Findings

This is the only nuclear deferral or variance account established by OPG that is not expressly authorized by O. Reg. 53/05.

The Board does not dispute that OPG incurred the costs in response to a directive from the Minister of Energy or that OPG recorded the costs accurately. The issue is whether the Board has any authority to approve recovery of out-of-period OM&A expenses booked in a deferral account that is not expressly authorized by O. Reg. 53/05.

OPG argues that Section 6(2)4 implicitly authorizes a deferral account because that section requires the Board to ensure OPG recovers costs related to refurbishing nuclear facilities, including assessment costs and pre-engineering costs and commitments.

The Board did not set payment amounts for the period April 1, 2005 to March 31, 2008. Its jurisdiction to set payment amounts, found in section 78.1 and O. Reg. 53/05, commences with the effective date of the Board's first order, which is April 1, 2008.

The Board has concluded that Section 6(2)4 can only reasonably be interpreted as being applicable to refurbishment-related OM&A expenses incurred on or after April 1, 2008. In the Board's view, had the government intended the Board ensure OPG recovers pre-April 2008 OM&A expenses for refurbishment activities, O. Reg. 53/05 would have explicitly directed such recovery, as they did with certain pre-April 2008 nuclear activities.

O. Reg. 53/05 requires the Board to ensure OPG recovers three specific pre-April 2008 non-capital costs related to nuclear activities: (i) Section 5(4) established a deferral account for non-capital costs related to the Pickering A return to service project; (ii) Section 5.1 authorized a deferral account for costs related to pre-April 2008 changes in nuclear liabilities; and (iii) Section 5.3 authorized a deferral account for pre-April 1, 2008 costs associated with planning new nuclear generation. In the Board's view, the fact that the government chose to direct the Board to ensure recovery of these specific pre-April 2008 non-capital costs supports the reasonableness of its interpretation of Section 6(2)4. In each instance, the government chose clear and explicit language when it intended the Board to ensure recovery of out-of-period non-capital costs. Absent such clear and explicit direction, the Board finds no basis on which to grant OPG recovery of non-capital costs incurred before April 1, 2008.

Additional support for the Board's interpretation of Section 6(2)4 is found in the most recent amendment to O. Reg. 53/05. Section 6(2)4.1 was added to the regulation in February 2008. It requires the Board to ensure that OPG recovers the costs incurred in the course of planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 53/05 uses the same language to direct recovery under section 6(2)4.1 as it did to direct recovery of refurbishment costs under Section 6(2)4 ("The Board shall ensure Ontario Power Generation Inc. recovers …").

Logically, OPG's interpretation of implicit authorization should be equally applicable to Section 6(2)4.1, that is, the creation of a deferral account to capture the costs directed to be recovered should be implicitly authorized by Section 6(2)4.1.

It is notable that when the government added section 6(2)4.1 to O. Reg. 53/05, it also added Section 5.3, a deferral account to capture the pre-April 2008 costs related to new nuclear activity. If OPG's interpretation was correct, the government would not have needed to do so as the authorization for the Section 5.3 deferral account would have been implicitly authorized by Section 6(2)4.1. That the government found it necessary to add Section 5.3 supports the Board's finding that absent clear and express direction to the contrary, the Board does not have the jurisdiction to review or order recovery of pre-April 2008 costs.

For the reasons above, the Board does not approve recovery of the $16.2 million recorded in this account.

7.1.5 Ancillary services/transmission outages and restrictions

The balances in these two accounts are relatively small and OPG's evidence is that the amounts are accurately recorded in accordance with O. Reg. 53/05. None of the intervenors objected to OPG's recovery of these balances.

Board Findings

The Board approves recovery of the balances as proposed by OPG.

7.2 Existing Hydroelectric Accounts

The December 31, 2007 hydroelectric deferral and variance account balances are much smaller than the nuclear balances and are presented in Table 7-2.

Because the net balance is relatively small, OPG did not propose a separate rate rider for recovery of the hydroelectric accounts. Instead, it proposed to deduct the net credit balance of $2.8 million from the test period hydroelectric revenue requirement.

Table 7-2: Hydroelectric Deferral and Variance Accounts, December 31, 2007

Account	Amount ($ millions)	Reg. 53/05 Section	Recovery Period	
			OPG Proposal	Maximum per Reg. 53/05
Water conditions	$ 6.7	5 (1) (a)	1.75 years	3 years
Ancillary services	6.7	5 (1) (c)	1.75 years	3 years
Segregated mode of operations	(11.5)	n/a	1.75 years	n/a
Water transactions	(3.0)	n/a	1.75 years	n/a
Interest (6%)	(1.7)	5 (3)	1.75 years	3 years
Total	$ (2.8)			

Sources : Ex. J1-1-1, Table 2; O. Reg. 53/05.

The accounts for segregated mode of operations (SMO) and water transactions are not required by O. Reg. 53/05. OPG earns revenue from segregating some of the units at the Saunders plant from the Ontario transmission system and reconnecting them directly to the Quebec grid. OPG also earns revenue when a portion of its Niagara water entitlement is used at the New York Power Authority's generating facilities. The balances in these deferral accounts are portions of OPG's net profits from these activities from April 1, 2005 to December 31, 2007. OPG has voluntarily proposed to share the profits because the SMO and water transactions were earned through the use of prescribed generation facilities.

No intervenors took issue with either the balances in the hydroelectric deferral and variance accounts or OPG's proposed method of recovery.

Board Findings

The Board accepts the balances in the hydroelectric deferral and variance accounts required by O. Reg. 53/05 and recovery of those balances over the test period.

As for the SMO and water transaction accounts, the Board concludes there is no basis for permitting clearance of this account. OPG is proposing to voluntarily share profits from SMO and water transactions that are not caught by O. Reg. 53/05 and that occurred before the Board took over regulating OPG's payment amounts. As noted earlier in this chapter in section 7.1.4 under "Nuclear development – Capacity refurbishments," the Board has concluded that it has no authority under O. Reg. 53/05 to make determinations on costs incurred or revenues earned by OPG before the effective date of the Board's first order unless there is express provision to that effect in the regulation.

The Board will not take these historical revenues into account when setting the OPG payment amounts.

7.3 Test Period Deferral and Variance Accounts

7.3.1 Continuation of existing accounts

O. Reg. 53/05 requires OPG to utilize three deferral or variance accounts for periods after the date of the Board's first order. Those accounts are:

- Pickering A Return to Service deferral account, per O. Reg. 53/05, Section 5(4),
- Nuclear liability deferral account, per Section 5.2, and
- Nuclear development variance account, per Section 5.4.

In addition, OPG proposed to continue these variance accounts:

- **Hydroelectric water conditions variance account**
  This account is to capture the revenue impacts of differences in hydroelectric electricity production due to differences between forecast and actual water conditions for the prescribed facilities. OPG indicated this is a continuation of the account authorized by Section 5(1)(a) of O. Reg. 53/05 for the period up to the date of the Board's first order.
- **Ancillary services variance account**
  OPG also proposed to continue the ancillary services variance account authorized by Section 5(1)(c) of O. Reg. 53/05. The account is intended to record variances between ancillary services revenues from the IESO included in the test period revenue requirement and the revenues actually realized.
- **Capacity refurbishment variance account**
  Section 6(2)4 of O. Reg. 53/05 requires the Board to ensure that OPG recovers capital and non-capital costs, and firm financial commitments, incurred to

increase the output of, refurbish or add operating capacity to a prescribed generation facility. This variance account is intended to capture differences between forecast amounts of such costs included in the test period revenue requirement and actual costs incurred.

Intervenors either supported OPG's request for these accounts or were silent in their submissions.

Board Findings

The Board authorizes OPG to establish the hydroelectric water conditions and ancillary services for the test period. As discussed earlier in this chapter, the Board disallowed the balance in the capacity refurbishment variance account proposed by OPG for the period before April 1, 2008. In light of the obligation imposed on the Board by Section 6(2)4, the Board accepts that a variance account is required for the period beginning April 1, 2008 and authorizes OPG to establish the capacity refurbishment variance account.

O. Reg. 53/05 requires OPG to maintain the PARTS, nuclear liability, and nuclear development accounts. As discussed in Chapter 5 on nuclear liabilities, the Board finds that the nuclear liability deferral account required by O. Reg. Section 5.2 should be restricted to the revenue requirement impact of changes in nuclear liabilities related to the prescribed nuclear facilities at Pickering and Darlington.

7.3.2 New Accounts Proposed by OPG

OPG requested approval to establish four new variance accounts:

- **Nuclear fuel expense**
  This account would capture the difference between the forecast and actual nuclear fuel expense during the test period. OPG proposed to determine a per MWh fuel expense based on the forecast fuel expense and production levels in its application. Entries to the account would be made when OPG's actual fuel expense per MWh differs from the forecast.

- **SMO, water transactions**
  This account would hold electricity consumers' shares of OPG's revenues from energy sales when the R.H. Saunders plant is segregated from the Ontario system, and consumers' share of revenues from water transactions with the New York Power Authority.

- **Pension/OPEB interest**
  OPG proposed this account to capture the impact of changes in the discount rate used to determine pension and other post-employment benefit (OPEB) costs. OPG is required by GAAP to reset the discount rate annually based on the state of the bond markets. The proposed account would only be cleared when the accumulated variance in pension and OPEB costs caused by a change in the discount rate, plus the forecast variance to the end of the bridge year, exceeds $75 million.

  The forecast pension costs for the test period have been calculated using a discount rate of 5.60%,[90] being the rate used by OPG to calculate the present value of its pension obligation at the end of 2007. OPG submitted that a change in discount rate, which is outside OPG's control, could have a material effect on pension and OPEB costs. It estimated that a 25 or 50 basis point change in the discount rate would result in a $50 million or $110 million change in pension and OPEB costs per year, assuming all other factors affecting the costs remain unchanged.

- **Changes in tax rates, rules and assessments**
  OPG proposed that differences between actual and forecast taxes, due to the following factors, be recorded in this account: (i) changes to tax laws that govern the determination of payments in lieu of income taxes, capital taxes, and property taxes; (ii) legislative or regulatory changes to municipal property tax rates; (iii) changes in, or disclosure of, new assessing or administrative policies of federal or provincial tax authorities, or court decisions for other taxpayers that will affect OPG; and (iv) tax assessments or re-assessments.

OPG also included in its application six potential future accounts that it wanted to "bring to the Board's attention the possibility that OPG may apply for a variance account via an

[90] Exhibit F3-4-1, page 24.

accounting order application in the event unforeseen material events/activities occur." The Board did not consider the potential accounts as OPG did not apply for the accounts.

There were no objections by any party to OPG establishing the nuclear fuel expense and SMO/water transactions variance accounts. Several intervenors did take exception to OPG's proposals for the pension/OPEB cost and tax variance accounts.

AMPCO, CCC, CME, SEC and VECC opposed the proposed pension and OPEB interest variance account. They argued that the Board should take the same approach for variances in OPG's pension and OPEB costs as it does for other entities regulated by the Board. CCC submitted that forecast risk and interest rate risk are fundamental business risks for a regulated entity, and that shareholders are compensated for such risks through the deemed capital structure and return on equity.

SEC noted, and OPG agreed, that the discount rate is only one factor that determines the amount of OPG's pension and OPEB costs in any year. SEC submitted that changes in other factors that affect OPG's pension and OPEB costs could lead to decreased costs. Allowing the proposed variance account, in SEC's view, would amount to single issue ratemaking.

OPG cited four Board decisions on rates for electric utilities in which the Board approved deferral or variance accounts for pension costs. OPG argued that the variance accounts for pension costs of Hydro One's distribution and transmission businesses provide a greater level of protection than the account sought by OPG.

In response to SEC's comment that the proposed account would capture the effects of only one cause of variation in pension and OPEB costs, OPG said it would not oppose increasing the scope of the account to capture the impact of changes in all factors.

Intervenors generally supported, or were silent on, the need to establish a variance account for taxes but several parties expressed concerns about OPG's specific proposal.

CCC supported the use of the account only for the effect of tax assessments and re-assessments related to the period after April 1, 2008, the effective date of the Board's first order. CME and SEC submitted that the parameters of the account should be compatible with those for the tax deferral account approved for use by electricity distributors. CME also submitted that the cost consequences of tax re-assessments for periods before April 1, 2008 should not automatically be recoverable in rates; for such re-assessments, CME suggests the Board should deal with requests for relief on a case-by-case basis. VECC also requested that before OPG clears any balances in the account in respect of re-assessments for past periods, customers should have an opportunity to explore the circumstances leading to the re-assessment.

OPG objected to CCC's proposal that the tax variance account be used solely for the impacts of tax assessments and reassessments for the period after April 1, 2008. OPG has resolved all issues related to the audit of its 1999 tax return,[91] and indicated it has incorporated the results of that audit in its estimate of tax losses for the 2005 to 2007 period. Based on the amount of those losses, OPG did not include any tax provision in test period costs. OPG submitted, however, that the results of audits of 2000 and later tax years could materially affect the amount of estimated tax losses for 2005 to 2007. OPG explained its rationale for requesting that the impact of all reassessments be recorded in the variance account as follows:

> OPG is seeking the inclusion of impacts of reassessments for the years prior to regulation by the OEB because it is voluntarily providing the benefits of the calculated tax losses from the 2005 to 2007 period. If there is a reassessment that reduces the actual losses for 2005 to 2007, then OPG would have given ratepayers a benefit that turns out not to have existed. In this circumstance, OPG believes it is entirely appropriate to include reassessments in the tax variance account.[92]

Board Findings

Nuclear fuel expense

The Board approves the nuclear fuel expense variance account as proposed by OPG.

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[91] OPG's 2008 Second Quarter Report, at pages 24 and 25, stated:

> In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit were unique to OPG and related either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. In the first quarter of 2008, a number of outstanding tax matters related to the 1999 tax audit were substantially resolved and as a result, OPG reduced its income tax liability by $85 million. During the second quarter of 2008, all remaining issues relating to the 1999 tax audit were resolved resulting in a further reduction of OPG's income tax liability of $21 million.

[92] OPG Reply Argument, page 147.

SMO and water transactions

In Chapter 3, the Board determined that revenues from SMO and water transactions would not be subject to variance account treatment, so there is no need for the Board to approve the proposed variance account.

Pension interest rate

The Board does not approve the proposed variance account related to changes in the discount rate used for pensions and OPEBs. The Board acknowledges that changes in the discount rate are outside OPG's control but that is true of many elements of OPG's proposed revenue requirement.

It has not been the Board's practice to allow regulated entities to establish variance accounts for changes in the costs of pensions and other benefits although there have been a few exceptions, as noted by OPG. The Board does not consider the two Board decisions on Hydro One's pension deferral accounts, which were cited by OPG, to be analogous to OPG's proposal. Unlike the account OPG has requested, the deferral account that Hydro One Distribution sought, and was granted, in 2004 was not intended to capture changes in pension costs that had not occurred but that might arise due to future changes in economic factors. Rather, the Hydro One Distribution account was established for known and material increases in pension costs above the amount included in rates.[93] The other Hydro One pension deferral account referenced by OPG (an account established in 2007 for Hydro One Transmission) was part of a settlement agreement accepted by the Board. As the Board has noted on other occasions, specific elements of settlement agreements have limited precedential value.

In the event that OPG's actual pension and OPEB costs during the test period are materially in excess of the amounts included in the revenue requirement, OPG would have the ability to apply to the Board.

Income and other taxes

The Board approves the variance account to track variations in municipal property taxes, and variations in payments in lieu of capital taxes, property taxes, and income taxes. The Board has authorized a tax variance account for electricity distributors (Account 1592, which deals with tax variances after April 2006[94]) that is used to record

[93] RP-2004-0180/EB-2004-0270, Decision and Order, July 14, 2004.

[94] Account 1592 is described in the Board's Accounting Procedures Handbook for Electric Distribution Utilities.

variations due to changes in tax rates or rules, new assessing or administrative practices of tax authorities, and tax re-assessments for past periods. The events and circumstances that give rise to entries into Account 1592 are essentially the same as those proposed by OPG, except that OPG includes court decisions for other taxpayers that will affect OPG's tax position. The Board finds that OPG's inclusion of variations due to court decisions for other taxpayers is appropriate.

The Board does not accept CCC's argument that only variances due to tax re-assessments for periods after April 1, 2008 should be permitted. The Board does not consider it appropriate to make use of the account more restrictive than Account 1592 is for electricity distributors.

With respect to income taxes, it is necessary to determine what the benchmark should be for measuring variations due to changes in tax laws and other factors. OPG did not address this issue in its evidence or argument. This is complicated by the fact that OPG did not include any provision for income taxes in its proposed revenue requirement on the basis that there are tax loss carry forwards for regulatory purposes. As set out in Chapter 9, the Board is uncertain about whether such regulatory tax loss carry forwards exist and, if they do, whether OPG was required to adopt the approach it took in its application.

To establish a benchmark to measure variations in taxes during test period, the Board directs OPG to calculate the income tax provision, before consideration of any tax loss carry forwards, which would result from the revenue requirement determined in accordance with this decision. That tax provision will not form part of the test period revenue requirement but should be used by OPG to calculate any variations in taxes that it records in the variance account.

The appropriateness and recovery period of any balance in the tax variance account will be reviewed by the Board when it considers OPG's next application. The Board notes that it has commenced a proceeding to deal with the disposition of Account 1562 (the tax variance account for electricity distributors for periods before May 2006) and that proceeding is expected to deal with variations in taxes due to tax audits and reassessments for past periods.[95] In a future hearing when the Board reviews any

[95] The Account 1562 proceeding (EB-2007-0820) was announced in March 2008. A staff discussion paper on the issues was released on August 20, 2008.

balance in OPG's tax variance account related to re-assessments, it will take note of any relevant decisions made by the Board in the Account 1562 proceeding.

7.3.3 New accounts proposed by intervenors

Two intervenors suggested that OPG be required to establish additional variance and deferral accounts.

In connection with its submission that the Board should cut OPG's proposed regulatory costs by 50%, CCC stated that OPG could establish a regulatory cost variance account to capture deviations from budget as OPG gains more experience with regulatory forecasting.

AMPCO recommended a variance account be approved in connection with its proposal that OPG be required to share 50% of any Congestion Management Settlement Credits received by OPG from the IESO, net of incremental costs.

AMPCO also proposed a variance account to capture variances between actual and forecast non-energy charges from the IESO (which OPG pays when the prescribed facilities consume power). AMPCO said these charges are difficult to forecast and submitted that OPG's forecasting methodology is questionable.

OPG did not agree that these accounts are required. It said its test period budget for regulatory costs is appropriate because it plans to file another cost of service application with the Board in 2009. It disagreed with AMPCO's submission that there is any net revenue from CMSC payments. And it disputed AMPCO's claim that OPG's forecasting methodology is suspect.

Board Findings

The Board agrees with OPG comments on the proposed accounts. It will not require OPG to establish the accounts. As noted in Chapter 4, the Board accepts OPG's forecast of regulatory costs and found a variance account is not required.

7.4 Interest Rates

OPG proposed that, for all deferral and variance accounts except PARTS, interest after March 31, 2008 should be accrued on the account balances at OPG's forecast rate for other long-term debt of 5.65% for 2008 and 6.47% for 2009.[96] For the PARTS account, OPG proposed to accrue interest using the weighted average cost of capital (WACC), which OPG proposed to be 8.48% for 2008 and 8.56% for 2009.

AMPCO, CCC, CME, VECC, and Board staff objected to OPG's proposed interest rates. They submitted that the rates should be set in accordance with the Board's interest rate methodology for regulatory accounts.[97] The arguments in favour of that approach were essentially that an unfortunate regulatory precedent would be set if the Board allowed OPG to depart from the Board's policy and that OPG has not established that its circumstances are sufficiently different from those of other regulated entities to justify special treatment.

Under the Board's policy, the interest rate for deferral and variance accounts is set each quarter at the prevailing three-month Bankers' Acceptance rate plus 25 basis points. The interest rate for the three months beginning April 1, 2008 was 4.08%. The rate was reset effective July 1, 2008 to 3.35%, and was kept at that level effective October 1, 2008.

OPG argued that its circumstances are substantially different from those of distribution utilities in terms of the size of the account balances and the length of time until full recovery. OPG noted the interest rates allowed by the Board in 2004 (before the Board's policy was issued) on the substantial deferral account balances for market ready and other transitional costs of electricity distributors were based, at least for some distributors, on long-term debt rates. OPG also submitted that it would be carrying deferral and variance account balances for longer periods than the distributors.

OPG characterized its request to use WACC to accrue interest on the PARTS account as an "exceptional situation" given OPG's proposed recovery period of almost 12 years.

Board Findings

The Board is not persuaded that OPG's circumstances are sufficiently different from those of other regulated entities to justify interest rates that are higher than those permitted by the Board's policy.

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[96] The proposed rates are set out in the pre-filed evidence at Exhibit C1-2-1, Tables 2 and 3.

[97] The policy is set out in a November 28, 2006 letter to Natural Gas Utilities and Electricity Local Distribution Companies, and is on the Board's website at http://www.oeb.gov.on.ca/documents/cases/EB-2006-0117/letter_accountinginterest_281106.pdf.

With the exception of the PARTS account, the Board has approved recovery of the balances in the existing deferral and variance accounts over periods not exceeding two years and nine months. With respect to PARTS, the Board determined that OPG should recover that balance over three years and nine months. These recovery periods are not substantially longer than the recovery periods for many deferral accounts of other regulated entities. And, in some cases, electricity distributors have been carrying deferral and variance accounts for longer periods.

With the Board's decision to shorten the recovery period for the PARTS account, the Board does not agree that the PARTS account represents an exceptional situation. The Board notes that, even if it agreed that an exception to its policy were warranted, it would not have granted OPG's request to accrue interest using OPG's WACC. Deferral and variance accounts are not rate base items and should not attract a rate base type of return.

The Board directs OPG to accrue interest on deferral and variance account balances after March 2008 using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy.

8 RATE BASE AND COST OF CAPITAL

8.1 Rate Base

OPG submitted that O. Reg. 53/05 requires the Board to accept the assets and liabilities as established by OPG's audited 2007 financial statements. The proposed regulated hydroelectric rate base is $3,885.5 million in 2008 and $3,869.9 million in 2009 and the proposed regulated nuclear rate base is $3,515.4 million in 2008 and $3,453.8 million in 2009. OPG has used the 2007 financial statements as the starting point and used the mid-year average methodology for in-service additions within the period. OPG maintained that capital costs for in-service additions included construction work in progress in 2007 financial statements and must be accepted for inclusion in rate base.

Table 8-1: Proposed Rate Base

	Hydroelectric		Nuclear	
$ millions	2008	2009	2008	2009
Gross plant at cost	4,433.2	4,480.6	4,531.7	4,733.2
Accumulated depreciation	570.2	633.1	1,737.8	2,037.1
Net Plant	3,863.1	3,847.5	2,794.0	2,696.0
Cash working capital	21.8	21.8	16.0	16.0
Fuel inventory	0.0	0.0	281.1	330.1
Materials and supplies	0.6	0.6	424.4	441.7
Total	**3,885.5**	**3,869.9**	**3,515.4**	**3,483.8**

Source: Ex B1-1-1, Tables 1 and 2.

Board Findings

The treatment of liabilities associated with nuclear waste management and decommissioning was the only significant aspect of rate base which was disputed in the proceeding. The Board's findings on that issue are set out in Chapter 5, namely that the return awarded on the rate base associated with the unamortized ARC and unfunded liabilities for Pickering and Darlington will be 5.6%. The balance of the rate base will be used for purposes of determining the amounts to be included in the revenue requirement for cost of capital related to the deemed capital structure and the return on equity. The Board accepts the remainder of the proposed rate base. If adjustments are needed as a consequence of any other findings in this decision, OPG should detail those adjustments in its draft order.

8.2 Capital Structure and Cost of Capital – Introduction

OPG's interim rates are based on a debt/equity ratio of 55/45 and a return on equity (ROE) of 5%. The following table sets out OPG's proposed capital structure and cost of capital for 2008 and 2009.

Table 8-2: Proposed Capital Structure and Cost of Capital

	2008		2009	
	% of Capital Structure	Rate	% of Capital Structure	Rate
Short-Term Debt	2.6%	5.83%	2.6%	5.98%
Existing/Planned Long-Term Debt	29.7%	5.79%	32.1%	5.79%
Other Long-Term Debt Provision	10.3%	5.65%	7.8%	6.47%
Total Debt	**42.5%**	**5.76%**	**42.5%**	**5.92%**
Common Equity	**57.5%**	**10.50%**	**57.5%**	**10.50%**
Total Rate Base	**100%**	**8.48%**	**100%**	**8.56%**

Source: Ex. C1-2-1, Tables 2 and 3.

OPG also proposed that the Board adopt a formula to be used for future adjustments to the ROE.

Ms. McShane provided evidence for OPG. Intervenors also presented expert evidence as follows:

- Board staff sponsored evidence by Mr. Goulding.
- The Pollution Probe Foundation (Pollution Probe) sponsored evidence by Drs. Kryzanowski and Roberts.
- VECC and CCC sponsored evidence by Dr. Booth.
- Energy Probe sponsored evidence by Dr. Schwartz.
- Green Energy Coalition (GEC) sponsored evidence by Mr. Chernick.
- AMPCO sponsored evidence by Dr. Murphy and Mr. Adams.

The following table summarizes the quantitative evidence of the witnesses.

Table 8-3: Summary of Expert Recommendations

Expert	Return on Equity	Capital Structure	
		Debt	Equity
Ms. McShane		42.5%	57.5%
Equity Risk Premium test	9.5-10.25%		
Discounted Cash Flow test	9.5-10.0%		
Comparable Earnings test	12.5%		
Recommendation	10.50%		
Dr. Kryzanowski / Dr. Roberts	7.35% (2008) 7.40% (2009)	53%	47%
Dr. Booth	7.75%	60%	40%
Dr. Schwartz	7.64%	55%	45%

This chapter will address the following issues:

- Capital structure
- Return on equity
- Cost of debt

8.3 Capital Structure

8.3.1 Approach to setting capital structure

CME submitted that the Board should begin with the premise that the debt/equity structure determined by the Province for purposes of setting the payments in the interim period was appropriate and that the structure should only change if there has been a material change in OPG's risks. CME pointed to OPG's testimony that its risks had not changed.

OPG responded that this position would have some merit if the prior capital structure had been set by the Board. OPG submitted that the Province adopted the interim equity ratio "as a transition to full cost of service rates established after an independent review by the OEB."[98] OPG pointed out that the level was set without a thorough cost of capital study and O. Reg. 53/05 clearly makes the Board the authority to set the payments. OPG also argued that if the Province thought the capital structure was appropriate, it could have indicated as such in O. Reg. 53/05. In OPG's view, the fact that the O. Reg. 53/05 does not stipulate the equity ratio supports the conclusion that the Province expected the Board to make its determination of the cost of capital on a commercial basis.

Board Findings

The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities.

The equity ratio underlying the interim rates is informative, but not determinative for purposes of the Board's decision; rather it is an expression of the Province's expectations at that time and its assessment of what would be reasonable in the circumstances. The Board agrees that an important distinction is that the equity ratio was not set under the auspices of a Board proceeding with evidence, testimony and argument.

The following factors were raised in the context of the risk assessment, each of which will be addressed in turn:

- The stand-alone principle
- Regulatory risk
- Operating risk

8.3.2 The stand-alone principle

Many regulated utilities are part of a broader entity that includes affiliates or non-regulated operations. Under the stand-alone principle, the regulated operations of the utility are treated for regulatory purposes as if they were operating separately from the other activities of the entity. The intent is that the cost of capital borne by customers, in respect of the regulated operations, should not reflect subsidies to or from other activities of the firm and should only reflect the business risks associated with the regulated operations.

[98] OPG Reply Argument, p. 9.

OPG has several characteristics which differentiate it from other utilities regulated by the Board. Both the regulated and unregulated operations are in the business of generating power for sale into the Ontario market; both the regulated and unregulated operations are owned by the Province. It is also the Province that has determined, in certain respects, the Board's current and future approach to setting payment amounts. That is the context in which the Board considers the application of the stand-alone principle to the regulated operations of OPG.

At issue in the hearing was whether in the course of setting an appropriate capital structure, the application of the stand-alone principle excluded a consideration of the significance of the Province's ownership of OPG as part of the assessment of business risks associated with the regulated operations.

OPG's position is that the matter of ownership should not be taken into account, and the cost of capital for the regulated operations should reflect what the cost would be if OPG were raising capital in the public markets on the strength of their own business and financial parameters. OPG noted that Mr. Goulding and Drs. Kryzanowski and Roberts agree that the stand-alone principle is a fundamental principle in determining the cost of capital.

OPG also noted that Mr. Goulding recognized the political risk which OPG faces due to changing power sector policies and that the bond rating agencies have highlighted political risk. Mr. Goulding's evidence was that the prescribed assets face greater political risk than transmission, distribution or merchant generators because these other entities are less likely to be used directly by government for policy purposes. Ms. McShane assessed that "the risk of future political intervention in the market is higher than in other Canadian jurisdictions."[99]

CCC, VECC, AMPCO, and CME all took the position that provincial ownership of OPG should be a factor in assessing OPG's risk and in determining the appropriate capital structure.

CCC took the position that the real shareholders are the residents of Ontario, and that the government is acting as their agent or proxy and is responsible for ensuring there is an adequate supply of electricity at reasonable prices:

[99] Ex. C2-1-1, p.64

> The Council submits that the facts require the Board to consider the capital structure and return on equity, not on the basis of what amounts to an artificial concept of a stand-alone entity, but on the basis of the reality that the government, because of its obligations to the residents of the province, has a stake in limiting the risks which OPG faces, and ensuring that OPG does not fail.[100]

CCC noted that the government had directed the OPA to include up to 14,000MW of baseload nuclear generation in its planning, directed OPG to refurbish existing and develop new nuclear capacity, and established a deferral account to recover the costs related to refurbished and new nuclear capacity. In CCC's view, "the government has exercised a power no private sector shareholder has, namely to direct the regulator to ensure risks which are taken in the public interest are protected."[101]

VECC made similar submissions:

> While the identity of any private group of shareholders or owners is not of relevance, ownership of a utility by the same entity that can simultaneously direct utility operations and direct regulatory treatment is of the utmost relevance in this case especially with respect to risk and return.[102]

VECC submitted that three factors reduce OPG's risk in relation to other utilities, especially unregulated generators:

- The requirements imposed on OPG through the MOA to mitigate the Province's financial and operational risk in operating the assets and reducing the Province's risk exposure to its nuclear assets
- The requirements in O. Reg. 53/05 that the Board accept certain amounts from OPG's audited financial statements and provide for recovery of various costs
- The various deferral and variance accounts which increase the probability of recovering unforecast costs

AMPCO submitted that the ownership of OPG affects the risks it bears and should be taken into account by the Board. AMPCO noted that both Standard & Poors' and Dominion Bond Rating Service recognize this in citing ownership of OPG as an important factor in determining OPG's debt rating. AMPCO pointed to the evidence it filed from Mr. Adams and Dr. Murphy, which concluded that the impact of past political

[100] CCC Argument, p. 8

[101] Ibid.

[102] VECC Argument, p. 14.

changes on OPG have been passed on to consumers. AMPCO questioned why, if political uncertainty creates risk for OPG, the shareholder should be compensated for a risk of its own creation. AMPCO concluded that regardless of the Board's findings, if the shareholder is dissatisfied with the risk borne by OPG, it can issue a further Directive to shift the impact to consumers.

CME submitted that Ms. McShane "misapplies the stand-alone principle by ascribing little weight to the risk mitigation effects of the government's ownership of OPG."[103] CME also disagreed with Ms. McShane's assessment of political risk:

> We submit that it is unreasonable to suggest that electricity consumers should pay a higher return because OPG's owner, the Government, might take some action which could harm the shareholder interest the Government holds in OPG. Ratepayers should not be burdened with higher Costs of Capital because the Government might decide to act in a way which causes harm to taxpayers as the ultimate owners of OPG.[104]

In response to CCC, OPG submitted that customers' interests must be kept separate from taxpayers' interest, and that this principle has been recognized by the Board in the past. OPG further submitted that the Province's objective of limiting its risk is no different than any other shareholder's, and that the proposed regulatory framework, including deferral and variance accounts, is a reasonable sharing of those risks and consistent with the approach of other utilities.

OPG argued that Hydro One is as important to the province as OPG and it is permitted to earn a commercial rate of return on a stand-alone basis.

OPG also argued that it was incorrect to claim that the government's legislative power has always been used to benefit or protect OPG. OPG pointed to the price caps of the early 2000s and the original requirement to decontrol a substantial portion of OPG's assets: "It is the very fact that the government can act both in ways to advantage and disadvantage OPG that creates uncertainty – and therefore political risk – in the future."[105]

[103] CME Argument, p. 50.

[104] CME Argument, p. 51.

[105] OPG Reply Argument, p. 14.

OPG also noted Ms. McShane's testimony that the circumstances suggest that the Province is trying to establish an arm's-length company and concluded as follows:

> To proceed on the assumption that the shareholder will intervene to protect OPG as an argument for ignoring the stand-alone principle directly contradicts the province's decision to place OPG's prescribed assets under the independent jurisdiction of the OEB.[106]

Board Findings

The stand alone principle is a long-established regulatory principle and the Board has considered its application in a variety of circumstances. The unique circumstances of OPG, however, are in many ways without precedent. As noted above:

- Both the regulated and non-regulated operations perform the same function (i.e., generate power).
- The owner is the Province.
- The Board's approach to setting the payments now and in the future have in some respects been determined by the Province (through O. Reg. 53/05).

OPG is also different from the other entities the Board regulates in that it is not a natural monopoly.

Risk, in the regulatory context, can be considered to be the magnitude of the range of potential outcomes, with the focus generally being on the potential for an adverse outcome. In other words, the greater the range of potential outcomes, the greater is the risk. The Board is faced with two questions when considering the appropriate application of the stand-alone principle in the assessment of risk for OPG:

- Should OPG's risk be considered lower than other regulated Ontario energy utilities because the Province as owner has substantial control over OPG's risks – either in creating them or in protecting OPG from them (shifting the risk to consumers)? This is the issue of the shareholder impact on a regulated entity's risk.
- Is the political risk higher for OPG's regulated assets than for other regulated Ontario energy utilities? This is the issue of the impact of electricity policy changes on risk.

[106] OPG Reply Argument, p. 16

The witnesses and the parties generally agreed that deferral and variance accounts affect the level of risk and reduce it from what it would otherwise be. Similarly, where O. Reg. 53/05 mandates the recovery of certain costs, it is agreed that this reduces risk. O. Reg. 53/05, and in particular the establishment of various deferral and variance accounts and the requirement that certain types of cost be recovered, operates to transfer risk from OPG to customers. The Board must consider the precise nature of the accounts and determine the impact on risk; this is discussed in more detail later in this chapter.

In summary, some of these protections relate to expenditures before the period of Board regulation (the PARTS account) or to activities beyond the operation of the prescribed facilities (recovery of Bruce costs and new nuclear costs). These do not affect the level of risk for the prescribed facilities in the test period. Some of the accounts are comparable to the accounts of other regulated entities; they have not been stipulated through O. Reg. 53/05 for the test period, but rather have been approved by the Board (the accounts related to tax changes, water conditions, nuclear fuel expense, and ancillary service revenues). OPG also applied for other accounts, which the Board has decided not to approve (OPEB changes and SMO and WT revenues).

Two significant protections related to the prescribed assets have been established by O. Reg. 53/05 and will be ongoing: changes in nuclear liabilities and refurbishment costs. These are significant additional protections which have been established by the government and exceed the level of protection typically granted to a regulated utility.

The Board's conclusion is that these accounts do reduce risk. The Board notes, however, that under O. Reg. 53/05, amounts placed in the deferral and variance accounts after the Board's first order will be subject to a prudence review. These accounts will operate the same way for OPG as they do for other regulated entities, although the breadth of protection is greater.

While OPG's risk is lower due to these accounts, should OPG be considered of even lower risk because the shareholder can control whether OPG's financial risks are borne by the customers or the shareholder? The Board concludes that it should not. To conclude that OPG is of lower risk would be comparable to assuming that, after the Board's first order, the Province will direct the regulation of the prescribed assets, and regulate the distribution of risks between OPG and its customers, beyond the protections already established and assessed for purposes of setting the capital structure. O. Reg. 53/05 is viewed by the Board as setting the baseline for OPG as it enters into a formal regulatory framework; essentially limiting any review of activities in the period prior to the Board's payment setting mandate and requiring protection against forecast error (subject to a prudence review) for certain significant costs going forward. The Board concludes that if OPG is operated at arm's length, then it should be examined in the same way as Hydro One, another energy utility owned by the Province. In other words, Provincial ownership will not be a factor to be considered by the Board in establishing capital structure.

The Board must also consider how it will address the shareholder's ability to control future risk. If the Province transfers risks from OPG to consumers in future, then the Board would need to assess the resulting level of risk and adjust the risk ranking (and possibly the capital structure) accordingly.

OPG suggests that its regulated assets are subject to greater political risk than other energy utilities in the province. The Board does not agree that this is a risk that should be reflected in OPG's cost of capital. All of Ontario's energy utilities are subject to risks arising from changing energy policy. The Province has established cost recovery requirements for utilities in which it has no ownership (for example, the regulations related to smart meter implementation). For example, the Province also required the LDCs to spend the third tranche of their market rates of return on conservation and demand management expenditures. The Board concludes that OPG's exposure to the risks and benefits of Provincial direction regarding expenditures and cost recovery are comparable to that of other regulated utilities.

The Board finds no evidence that OPG's regulated hydroelectric and nuclear facilities will be uniquely exposed. Mr. Goulding's evidence suggests that the risk of political interference is higher for OPG, but precisely because the Province is the owner and may choose to use OPG in a way which would be adverse to OPG's financial interests. It would not be appropriate for the Board to assume that the Province will interfere in the distribution of OPG's risks now that the Board has regulatory authority over OPG; it is consistent therefore to regulate OPG on the basis that the Province will not control OPG's currently regulated facilities in a manner which is adverse to OPG's commercial interests. The stand alone principle leads us to conclude that OPG's financial risks are not lower as a result of Provincial ownership; therefore it is consistent to conclude that political risk is not higher as a result of Provincial ownership.

8.3.3 Regulatory Risk

OPG noted that this is OPG's first application under the Board's regulatory authority. In OPG's view there is no track record of stable or consistent regulation and, therefore, there is regulatory uncertainty about the regulatory end state and OPG's ability to recover its costs. As a result, OPG argued, there is a risk of unintended consequences from specific decisions until there is a track record of consistent, stable regulation.

AMPCO pointed to Ms. McShane's evidence wherein she assumes the Board will regulate OPG the way it regulates other utilities and that the Board will provide OPG with a reasonable opportunity to recover its costs and earn a risk related return. AMPCO concluded that this was inconsistent with the claim that OPG's regulatory risks are higher than for other utilities. AMPCO noted that Dr. Booth and Drs. Kryzanowski and Roberts agreed that OPG did not face higher regulatory risk. Pollution Probe pointed, in particular, to Drs. Kryzanowski and Roberts's testimony that regulatory risk is low in reality because the Board has extensive experience with regulating gas and electric utilities, even if it has not regulated OPG previously. CCC and CME also disagreed that OPG's regulatory risks are higher than for other utilities.

OPG noted that both Ms. McShane and Mr. Goulding recognized the regulatory risk associated with the newness of OPG's regulatory regime. In OPG's view, it is not an issue of the Board's competence or integrity; it is an issue that there is not yet an established track record.

OPG also submitted that it faces operating risk from the fact that it is regulated by the Canadian Nuclear Safety Commission (CNSC) which has powers to make orders, including without a hearing in the event of an emergency, the consequences of which have the potential to impose significant costs on OPG. OPG argued that these powers are a significant factor in the regulatory risk assessment.

Board Findings

The Board finds that there is little evidence to support the conclusion that OPG's regulatory risk is higher than that of other regulated energy utilities because of its new regulatory framework. Hydro One and the electric LDCs were also new to Board determined cost of service regulation, but no evidence was presented that those entities were exposed to higher regulatory risk. It is also important to note that the Board's regulatory process provides ample opportunities to address issues of cost recovery through applications, deferral accounts, and motions to review. These are standard and well established regulatory tools; cost of service is a long established regulatory framework; even incentive regulation is well established.

The Board does accept that there could be some risk associated with the uncertainty of applying cost of service regulation, which is typically applied to natural monopolies, to generation assets in Ontario's hybrid market. However, the Board notes that throughout North America there continues to be rate regulation of generation facilities, and that the traditional models of cost of service or incentive regulation are applied in these circumstances. The Board concludes that the risk is therefore minimal.

The risk with respect to the CNSC is whether OPG would be able to recover the costs arising from CNSC action. The Board does agree that it is a category of costs not faced by other regulated Ontario utilities. However, the Board expects that were such costs to arise, OPG would apply for recovery through an application, as would any other regulated entity faced with a significant cost which it claimed was beyond its control and imposed by a body with the authority to do so. The Board would consider the application in the normal way, including a test of prudence.

The Board concludes that regulatory risk is not a significant factor for OPG and is not materially higher for it than for the other utilities the Board regulates.

8.3.4 Operating Risk

For OPG, operating risk entails outage risk, dispatch risk, non-payment risk and the risk associated with environmental obligations. There was general agreement that electricity generators have greater operational risks than non-generation entities regulated by the Board. It was also generally agreed that OPG's risks were lower than those of merchant generators. Given the proposed continuation of the deferral account covering fluctuations in water availability during the test period for the hydroelectric operations, the focus was largely on OPG's nuclear operations and primarily on the risk related to forced outages and dispatch.

OPG took the position that although much has been made of deferral and variance account protection in this case, most of the accounts are simply reflections of the prohibition against retroactive rate making; i.e., they are designed to ensure the recovery of costs associated with initiatives that were directed, authorized or approved by the government before the introduction of rate regulation by the Board. OPG also noted that operating and production risk is the largest risk it faces as nuclear technology is more complex than other types of generation and is subject to a higher risk of unanticipated costs of repair, and loss of production and revenues.

One of the risks that OPG and Ms. McShane identified is dispatch risk. This is the risk that baseload generation from OPG's regulated assets will not be dispatched because of economic conditions and/or the presence of generators with lower marginal costs. AMPCO submitted that this risk is insignificant and pointed to Ms. McShane's analysis of the Ontario market over the last three years. In AMPCO's view, her analysis shows that even at low levels of demand there is the opportunity for additional baseload capacity to be added without a risk that OPG's regulated assets will not be dispatched. AMPCO also noted the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, both of which concluded that dispatch risk is low. CME supported AMPCO's submissions. In the end, there was limited dispute that dispatch risk for OPG is low.

AMPCO submitted that there appears to be a consensus that the major risk facing OPG is related to the operation of the nuclear units. AMPCO submitted that these risks are largely mitigated: ONFA limits OPG's potential liabilities, as changes in the nuclear liability resulting from changes to the decommissioning reference plan are recovered through a variance and deferral account; other deferral and variance accounts cover unexpected costs related to nuclear regulatory costs and technological changes, and the non-capital costs associated with the Pickering A return to service; and new accounts are proposed to cover variances in nuclear fuel costs, pension costs, and taxes.

AMPCO pointed to the evidence of Dr. Booth as supporting the conclusion that the variance and deferral accounts effectively transfer operational risks to consumers. AMPCO submitted that the remaining operational risks are within the control of management and are not risks for which OPG should be compensated.

CCC submitted that while the nuclear assets are undoubtedly riskier than the hydroelectric assets, many of the risks have been covered off with deferral accounts and the only substantive remaining risks are production and operating risks. In CCC's view, "It is inconceivable that the government would allow OPG to be materially adversely affected by production or operating risks."[107] CCC submitted that these risks can be mitigated by increasing the fixed portion for nuclear payments to 50%.

CME submitted that if the proposed additional variance and deferral accounts and the fixed nuclear payment are approved, then the equity ratio should be reduced to 40% in recognition of the reduction in risk from these mechanisms.

OPG replied:

> It was Mr. Goulding's opinion, shared by Drs. Kryzanowski and Roberts, that OPG's nuclear assets are far more exposed to potential loss of revenues due to operational risk than a transmission or distribution network. The operational risk associated with OPG's prescribed assets is, in fact, the principal risk that faces OPG.[108]

OPG submitted that none of OPG's nuclear production risk is mitigated by a deferral or variance account. OPG argued that Dr. Booth's contention that all of OPG's risks are covered by deferral and variance accounts does not recognize that deferral and variance accounts are a common feature of regulated utilities or that OPG does not have an account to cover nuclear production risk. Further, OPG argued that Dr. Booth had not reviewed the ONFA or analyzed the actual extent of the nuclear liabilities and OPG's risk related to residual unfunded liabilities and the limits on the provincial guarantee cap. In OPG's view it still faces significant exposure to this item, even with the related deferral and variance account.

With respect to the deferral and variance accounts generally, OPG characterized them as being designed to prevent "hindsight re-examinations of historical decisions and commitments made long before the OEB acquired jurisdiction to determine payment amounts."[109] In OPG's view, the most recently established accounts reflect the reality that the Board was not the regulator at the time.

All of the experts acknowledged that the use of deferral and variance accounts reduced risk. Ms. McShane testified that her recommendations were based on the assumption that the proposed variance and deferral accounts are implemented. She estimated that if the new proposed accounts (related to nuclear fuel, OPEBs/Pension costs, and tax

[107] CCC Argument, p. 18.

[108] OPG Reply Argument, p. 17.

[109] OPG Reply Argument, p. 22.

changes/assessments) were not implemented, the increased risk would warrant an upward adjustment to either the equity ratio or the ROE.

OPG argued that the evidence is clear that Ms. McShane's recommendations are premised on the approval of the proposed deferral and variance accounts, and that if they are not approved, the equity ratio and/or ROE would need to be adjusted accordingly. OPG submitted that if the scope of the accounts, including, for example, the Nuclear Liabilities Deferral Account, is reduced, then OPG's risk will increase which would need to be reflected in the cost of capital.

Mr. Goulding testified that the fixed payment component would reduce OPG's business risk and pointed out that this payment structure would not be available to merchant generators nor to the generators under contract with the OPA. Ms. McShane estimated that without the fixed payment component, the ROE would need to increase by about half the increase in the variability, approximately 25 basis points, or the equity component should be increased to 60%.

Board Findings

The Board finds that while the dispatch risk for the regulated facilities is low, the operational and productions risks, particularly for the nuclear assets, are significant. Some of these risks are mitigated by the existing and ongoing deferral and variance accounts, but the accounts do not cover all of the risk, particularly not the risk of forced outages and the corresponding impact on costs and production. The accounts fall into four categories: those not related to the prescribed assets; one which provides for recovery of costs which pre-date the Board's regulation of OPG; those that have been specifically approved by the Board in this decision and are typical of utility variance and deferral accounts; and those which provide extended protection against forecast variance. We will review each in turn.

Some of the accounts and cost recovery protection mechanisms contained in O. Reg. 53/05 do not relate to the prescribed assets. The Board is required to ensure that OPG recovers the costs associated with Bruce and the costs associated with new nuclear build. Although these represent significant shifts of costs and risks to customers, they are not related to the regulation of the prescribed facilities. The Board finds that although these requirements may lower OPG's risk as a corporation, they have no impact on the risks of the prescribed facilities.

One of the accounts relates to circumstances and decisions taken before the period in which the Board has regulatory authority. The PARTS account is related to non-capital expenditures related to Pickering A which pre-date the period of the Board's regulatory authority. No new amounts will be added to this account; it is being maintained as the amounts are recovered over the next four years. The Board concludes that this account has no significant impact on OPG's risk in the test period, as the expenditures pre-date the Board's regulatory authority.

Some of the approved accounts going forward are related to protection against forecast error, namely tax changes, nuclear fuel cost, water conditions and ancillary services. The Board concludes that while these accounts each reduce risk, they are not dissimilar to the accounts of other regulated utilities. The electric LDCs have accounts related to tax changes; the ancillary services account ensures customers receive the full benefit of these revenues; and the nuclear fuel and water accounts, while providing protection against inputs over which OPG has little control, are not large relative to the size of OPG's revenue requirement.

The Board is also required to ensure that OPG recovers the revenue requirement implications of changes in the nuclear liabilities Reference Plan and the costs of the refurbishment of the prescribed nuclear facilities. These represent a more extensive risk protection than might typically apply to a regulated utility. Although the nuclear liabilities are unique to OPG, the deferral account ensures that OPG is kept whole and the impact of any change in the Reference Plan is borne by customers. This protects OPG against a significant risk. The refurbishment account provides protection against forecast variance in non-capital costs; this could be significant given the high levels of project OM&A. While the account also provides protection related to capital costs, these costs will not be included in rate base until the assets are in-service in any event and therefore the account does not provide significant additional risk protection. The requirement for a prudence review continues to provide a measure of protection to customers and ensures that OPG retains some risk.

The Board notes that future accounts may be established which further reduce risk; however, that factor is not determinative of the Board's assessment of the current level of risk. The proposed payment structure would also mitigate some of the risk, but as set out in Chapter 9, the Board has determined that it is not appropriate to include a fixed component in the payment structure.

The Board concludes that OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation (for example, given the risk reduction afforded by some of the deferral and variance accounts). The Board also concludes that it is not appropriate for the shareholder to be compensated for all of the operational risks associated with the regulated nuclear facilities. Under cost of service regulation OPG has the opportunity to forecast production and operating costs and to seek recovery of the associated revenue requirement. The Board concludes that it would not be appropriate for shareholders to be fully compensated for the risk that those forecasts are incorrect given that management controls the development of the forecasts and has some considerable control over the achievement of those forecasts.

8.3.5 Capital Structure Conclusion

CCC concluded that OPG was no riskier than any other utility and that Dr. Booth's recommended equity ratio of 40% was appropriate. Similarly, AMPCO took the position that OPG and Ms. McShane have exaggerated the risks facing OPG and concluded that the equity ratio should remain unchanged. SEC submitted that the equity component should be 47%, representing 40% for hydroelectric and 50% for nuclear. OPG replied that those who have recommended lower equity ratios than Ms. McShane have underestimated OPG's business risk.

Board Findings

Union Gas Limited and Enbridge Gas Distribution Inc. both have equity ratios of 36%, and the risk differential between Union and Enbridge is reflected in Union's ROE which is 15 basis points higher. The electric LDCs and Hydro One have equity ratios of 40%, and Great Lakes (transmission) has an equity ratio of 45%. The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation. And while the deferral and variance accounts mitigate some aspects of OPG's risk, they do not protect against outage risk.

The Board finds that the proposed equity ratio of 57.5% is excessive. The incremental level of risk does not warrant the additional 12.5% equity over that of the next highest regulated utility. It is also well in excess of the equity levels of merchant generators, who have higher risk than OPG, as pointed out by Mr. Goulding. The Board concludes that the recommendation of Drs. Kryzanowski and Roberts, namely an equity ratio of 47%, is appropriate in the circumstances. This ratio is higher than the equity ratio of any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG. The Board notes that this deemed capital structure will be applied to the rate base which is net of the specific treatment to be applied to the nuclear liabilities related to Pickering and Darlington (which is discussed in Chapter 5).

8.4 Return on Equity

8.4.1 Introduction

Ms. McShane used three tests: the Equity Risk Premium ("ERP") test, the Discounted Cashflow ("DCF") model test and the Comparable Earnings ("CE") test. For the ERP test, she used three approaches:

- Capital Asset Pricing Model ("CAPM")
- Historical utility risk premium test
- Discounted Cash Flow ("DCF") risk premium test

Although Ms. McShane updated her estimates of the various tests in April 2008, the result was no change in the aggregate ROE recommendation: in her view, the lower government interest rate is partially offset by a higher risk premium which is reflected in a higher spread between government bonds and long-term A-rated utility bonds.

Pollution Probe submitted that the Board should prefer and accept the recommendations of Drs. Kryzanowski and Roberts. They used four methods to estimate the market equity risk premium: the Equity Risk Premium (including CAPM) methodology and three other methods to support the "directional conservatism" of the estimate derived from the ERP method. Pollution Probe noted that OPG acknowledged that this was now the dominant methodology used for regulated energy utilities in Canada.

CCC submitted that the Board should prefer the testimony of Dr. Booth to that of Ms. McShane. Dr. Booth estimated that OPG will have sufficient financial flexibility to access capital markets on reasonable terms with an ROE of 7.75% and an equity ratio of 40%. Dr. Booth relied on a CAPM risk premium model and a two-factor model, with the CAPM estimate based on an historic average market risk premium adjusted for the changing risk profile of the long Canada bond, and the two factor model taking into account the interest rate sensitivity of utility stocks.

CCC noted that the average return on the Canadian equity market has been 10.42% over the period 1924-2007 and that current allowed ROEs are generally less than 9% for utilities on a formula mechanism. CCC submitted that Ms. McShane's recommendation of 10.5% ROE on a 57.5% equity ratio implies that OPG's risk exceeds that of other regulated Canadian assets by a considerable margin. In CCC's view, there is no factual basis for this view. VECC supported CCC's submissions.

SEC submitted that the critique by Drs. Kryzanowski and Roberts of Ms. McShane's evidence and the cross-examination of Ms. McShane, which revealed the utility-side biases in her evidence, lead to the conclusion that her evidence is not credible and should not be relied upon by the Board. SEC also expressed concern with Dr. Booth's continuing view that Canadian allowed utility ROEs are too high, due to incorrect analysis by regulators of the risk mitigation effect of the ROE method being used, and noted that this conclusion has generally not been accepted. SEC concluded that Drs. Kryzanowski and Roberts' evidence was the most thorough and rigorous, and should be adopted by the Board in setting ROE.

OPG submitted that there was a fundamental contradiction in the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, in that both recognized that OPG was of higher risk than other Canadian utilities, yet both made recommendations for ROE below that of any regulated Canadian utility.

First, the Board will address the alternative approaches to setting the ROE proposed by CME, AMPCO, and Dr. Schwartz and Energy Probe. We will then turn to a discussion of the various analytical tools used by Ms. McShane, Dr. Booth and Drs. Kryzanowski and Roberts.

8.4.2 Alternative approaches (CME, AMPCO, Dr. Schwartz and Energy Probe)

AMPCO submitted that the use of CAPM and DCF models is inappropriate for OPG's heritage assets.

> AMPCO submits that OPG is a financial hybrid with a government-assigned ROE reflective of its character as a government-owned, but commercially structured body. In AMPCO's view, the initial conditions established in O.Reg. 53/05 were well considered at the time of issuance and remain appropriate…The setting of the ROE was a fair solution that recognized the role consumers had played in assuming stranded debt obligations while at the same time providing for OPG's financial needs.[110]

In AMPCO's view, the current ROE has not prevented OPG from undertaking capital projects and the credit rating agencies have indicated that OPG's financial performance has improved under the current arrangements. AMPCO concluded that "the ROE should be set to the true cost to the shareholder of having assumed this segment of OPG's debt obligation to the OEFC, namely the interest rate on this debt, which is 5.85%."[111]

CME submitted that the ROE should be between 5.85% and 8.57% (the most recently approved level for Hydro One), and should be set at the lower end of the range given the acknowledgement by the government in its February 23, 2005 announcement that the 5% ROE ensures a fair return to taxpayers.

OPG responded that a return of 5.85% violates the stand-alone principle, regulatory principles, and finance principles:

> CME and AMPCO miss the central point: that the return the government or any other investor would expect from its investment is one that reflects the riskiness of the project it is investing in, not the cost incurred to raise the capital for the investment.[112]

OPG also pointed to Mr. Goulding's testimony that "OPG should not be compelled by the regulator to suppress what would otherwise be just and reasonable equity returns to serve other policy objectives."[113] With respect to the upper bound of CME's proposed range, OPG responded that OPG's ROE should be no less than Hydro One's.

In applying the CAPM test, Dr. Schwartz used a Treasury bill rate (3.24%) and estimated the equity market risk premium at 6.7% over the Treasury bill yield. He

[110] AMPCO Argument, p. 29.

[111] AMPCO Argument, p. 31.

[112] OPG Reply Argument, p. 11.

[113] Tr. Vol. 12, pp. 111-112.

adjusted this premium by the 0.65 adjusted beta (the median of Ms. McShane's range for the median Canadian utility). Dr. Schwartz's evidence was that the long-term bond yield overstates the risk free rate unless the premium for holding a longer-term instrument is removed.

Energy Probe submitted that the test of whether Dr. Schwartz's recommendations are more appropriate than Ms. McShane's is whether the ROE and capital structure "produce a plausible and reasonable estimate of fair market asset value."[114] Energy Probe submitted that Ms. McShane's recommendations support a fair market value of $6.2 billion, which is below book value, and hence results in the shareholder being over-compensated. Dr. Schwartz's recommendations support a fair market value of $9.9 billion, or 1.3 times book value, which is more reasonable in Energy Probe's view.

SEC submitted that Dr. Schwartz's evidence was of limited value given his unfamiliarity with the standard regulatory approach. Although a private sector analysis of OPG would be a useful approach, SEC submitted that "the expert will still have to be able to articulate the differences between that fresh, private sector point of view, and the regulated entity point of view that it is proposed to supplant."[115]

Board Findings

The Board agrees with OPG that it would be inappropriate to set OPG's ROE at 5.85%. This rate does not represent the cost of capital for OPG's regulated facilities; it is the interest rate on OPG's prior debt obligation to the OEFC. The Province may have assumed this debt, but that is related to the shareholder's cost of capital, not OPG's cost of capital.

The Board finds while it is relevant to consider Hydro One's ROE, and the ROEs of other regulated utilities, they are not determinative of the appropriate ROE for OPG. It is appropriate to determine OPG's ROE using the standard tests for establishing a benchmark return. This reflects the Board's long-standing approach to these issues.

The Board concludes that while Dr. Schwartz presented novel ideas, he was unable to address his recommendations within a regulatory context. As a result, the Board did not rely on his evidence for purposes of setting the cost of capital.

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[114] Energy Probe Argument, p. 18.

[115] SEC Argument, p. 7.

8.4.3 Review of standard tests for establishing a benchmark return

The Discounted Cashflow ("DCF") Test

PWU noted Ms. McShane's testimony that the DCF test has the advantage of estimating the cost of equity directly because it relies on analysts' projections. PWU pointed to Ms. McShane's testimony that her examination of the analysts' forecasts back to 1993 (for the DCF risk premium test) found the average forecast was about 60 basis points lower than the consensus forecast for economic growth, concluding there is no reason to believe investors would view analysts' estimates as systematically optimistic.

Pollution Probe noted the testimony of Drs. Kryzanowski and Roberts to the effect that the DCF model is more appropriately used at the level of the overall market, rather than the firm or industry level. Pollution Probe also submitted that Ms. McShane has not adjusted the results for the bias in analyst forecasts: "This bias is widely documented for samples that include utilities, and, absent evidence showing that the bias does not apply to utilities, there is no reason why an adjustment should not have also been made in this case."[116]

CCC noted that Dr. Booth used the DCF method (estimating a DCF return for the market as a whole) as a check only, because of the endemic data problems and the lack of pure play utilities. CCC pointed to Dr. Booth's testimony that the latest research indicates the forecast bias at an average of 2.84% and that Ms. McShane's estimates have not been adjusted for this bias.

OPG responded that there was no need to make an adjustment for optimism bias because there was no evidence or reason for such a bias in the utility context. OPG also noted that the DCF test is the one relied on by US regulators who would presumably be aware of this alleged optimism bias but continue to find the DCF test, based on the analysts' forecasts, compelling.

Comparable Earnings Test

Pollution Probe noted Drs. Kryzanowski and Roberts' criticisms of the CE test and maintained that the Alberta Utilities Commission gives no weight to the CE test. Pollution Probe submitted that "when common finance tests are applied, the rate of

[116] Pollution Probe Argument, p. 6.

return in Ms. McShane's sample abnormally outperforms the S&P/TSX Composite, especially given that this sample represents firms with low risk relative to the market."[117] Energy Probe also submitted that the Board should disregard the CE test approach.

CCC noted Dr. Booth's testimony that while it is appropriate to examine the returns of Canadian companies to establish where we are in the business cycle, it is not appropriate to use this data to establish a fair ROE.

OPG responded that all of the tests have their drawbacks, but the CE test is useful in the context of the fair return standard as a measure of fair return based on the concept of opportunity cost. OPG noted that some of the criticisms of the CE test by Drs. Kryzanowski and Roberts (disagreements as to the appropriate time period and treatment of structural changes in the economy, and the fact that the rates are backward looking) are equally applicable to the CAPM. OPG maintained that formula returns driven by the CAPM test alone are too low.

Equity Risk Premium ("ERP") Test

The ERP test considers three factors: the long-term risk free rate, the market equity risk premium, and the relative risk adjustment for a benchmark Canadian utility (or beta coefficient). There was some disagreement amongst the experts as to the forecast of the risk free rate, but the differences were more marked in relation to the estimation of the market equity risk premium and the appropriate beta coefficient. These differences result in material differences in the recommendations. AMPCO noted that having started with essentially the same data, Ms. McShane ends up with a much higher "bare bones" ROE recommendation of 9.25%-10.25% than Dr. Booth (7.25%) or Drs. Kryzanowski and Roberts (6.35% and 6.75% for 2008 and 2009, respectively).

Ms. McShane estimated the market risk premium at 6.5%; Dr. Booth and Drs. Kryzanowski and Roberts estimated it to be 5%. AMPCO submitted that the evidence based on Canadian data over long time periods indicates a market risk premium of 4.5%-5.5%, and that a shorter time period yields a lower market risk premium.

OPG noted that achieved equity returns have remained relatively constant. This, coupled with increasing long Canada returns, has tended to shrink the achieved market equity risk premium. Forecast long Canada yields are much lower, and therefore, in

[117] Pollution Probe Argument, p. 7.

OPG's view, Drs. Kryzanowski and Roberts' estimate is downwardly biased: "They have not given sufficient recognition to market equity risk premium increases resulting from lower anticipated bond market returns."[118]

OPG submitted that Dr. Booth's evidence regarding government budgets and the bond market supports a conclusion that bond returns in the future are expected to be lower than historically. OPG concluded that "the Canadian equity risk premium under current capital market conditions is higher than the observed risk premium."[119] OPG concluded that the equity risk premium must be substantially higher than Dr. Booth's estimate of 5%, and must be at least 6.5% if equity returns remain stable at 11.2%-11.6% and the forecast yield on government bonds is 4.5%.

While both Dr. Booth and Ms. McShane use adjusted betas for the relative risk adjustment, they adjust their beta data differently. Ms. McShane adjusted the betas to estimate a relative risk adjustment of 0.65-0.70; Dr. Booth and Drs. Kryzanowski and Roberts estimated the adjustment to be 0.50.

CCC submitted that because Ms. McShane adjusts the raw betas by averaging them with 1.0, they are generally increased because utility betas are almost always less than 1.0. Dr. Booth also adjusts his beta estimates upwards, but based on recent market conditions.

AMPCO pointed to the evidence of Drs. Kryzanowski and Roberts and Ms. McShane which indicate a downward trend in beta. AMPCO noted Ms. McShane's adjustment to correct for interest sensitivity of regulated utilities introduces a bias towards the value of one, whereas Dr. Booth and Drs. Kryzanowski and Roberts's adjustments for the same issue do not alter their beta estimates significantly.

OPG responded that Dr. Booth and Drs. Kryzanowski and Roberts's betas are too low and maintained that use of adjusted betas "recognizes that 'raw' utility betas do not adequately explain utility returns; their use mitigates the deficiencies in raw betas as a predictor of future returns."[120] Dr. Booth and Drs. Kryzanowski and Roberts only adjusted their betas by taking averages of 'raw' betas, which is not the appropriate adjustment in OPG's view.

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[118] OPG Reply Argument, p. 28.

[119] OPG Reply Argument, p. 29.

[120] OPG Reply Argument, p. 31.

Board Findings

It is important to emphasize that the establishment of the ROE is for purposes of the prescribed assets only; it is not related to OPG's unregulated businesses, nor is it related to attracting capital for new generation build which is unregulated.

The Board finds that each of the analytical tests has value as each provides a different perspective on the question of the appropriate ROE. However, each test also has its weaknesses. For example, there is evidence of analyst bias, which although not conclusive with respect to utilities, suggests that the DCF cannot be relied upon wholly. These weaknesses were highlighted during the testimony of the experts and in references to other studies in the financial literature. In all cases, significant judgment is brought to bear by the experts because historical data are being used to estimate the future. In addition, the data may not be sufficiently comparable; if, for example, it is U.S. data, or there may be varying time periods under consideration. As Ms. McShane acknowledged, each test is a "blunt instrument."[121]

The Board concludes that the various expert recommendations provide the reasonable range of results, but the extremes of the range (both highest and lowest) should not be adopted given these inherent limitations in the methodologies.

The Board concludes that the ERP test is the most reliable test upon which to base its determination. The Board has the benefit of having had a number of experts develop their recommendations based on this approach. As noted above, each test includes important elements upon which the expert must apply judgment. For the ERP test, judgment is applied in determining the appropriate adjustment to the raw betas and in estimating the appropriate market equity risk premium. The Board accepts that an upward adjustment of the raw betas is warranted, and, similarly, that changes in the anticipated bond yields may require an adjustment to the observed market equity risk premium. However, the Board concludes that no particular approach by a single expert is wholly reliable. The Board considers it reasonable to consider the range of risk premiums in determining the appropriate level, but neither extreme of the range is appropriate. The estimates of the risk premium range from about 2.5% to over 5%, although these are applied to different forecasts of the risk free rate. The Board concludes that a risk premium of 3.4% is appropriate in the circumstances, based on the Board's judgment of the evidence before it and the previously discussed factors.

[121] Transcript Vol. 10, p. 17.

Using a forecast long-term risk free rate of 4.75% and a risk premium of 3.4%, the resulting "bare bones" ROE would be 8.15%.

8.4.4 Adjustment for financing flexibility

The purpose of adding an adjustment for financing flexibility to the "bare bones" cost of equity is to compensate the utility for potential equity flotation issuance costs and to protect the financial integrity of the utility against any adverse impacts from potential unexpected events in the capital markets and the economy.

Energy Probe submitted that adding 50 basis points for financial flexibility was unwarranted as OPG will not issue shares and therefore requires no compensation for floatation costs. AMPCO agreed with Dr. Schwartz that the reasons given for adding 50 basis points for financial flexibility are unconvincing: all of OPG's borrowing will be from the OEFC and there is no expectation that equity will be raised in the test period.

OPG responded that the 50 basis point allowance does not turn on whether the utility is actually forecast to enter the market or not. It is a margin for unanticipated market conditions and "recognizes the basic principle of regulation, that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value."[122] OPG maintained that this principle is well established and noted that Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane all included the provision and that it has been included in setting the ROE for Hydro One and the electricity LDCs.

Board Findings

The Board will include this adjustment of 50 basis points. The adjustment has been used in the past and forms part of the recommendations made by Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane. Adding 50 basis points to the "bare bones" ROE of 8.15% results in an ROE of 8.65%. The Board concludes that this result is also reasonable because it is comparable to the levels of return allowed to other Ontario regulated energy utilities, and although OPG is of higher risk, that risk has been recognized through the higher equity ratio.

[122] OPG Reply Argument, p. 35.

8.4.5 Should there be separate costs of capital for regulated nuclear and regulated hydroelectric?

GEC-Pembina-OSEA took the position that OPG should recognize the higher risks of the nuclear business in its capital and OM&A expenditure decisions. GEC-Pembina-OSEA sponsored the evidence of Mr. Paul Chernick on this issue. GEC-Pembina-OSEA concluded:

> The Board should select an acceptable combined cost of capital (with the deferral accounts it finds acceptable in place) and then adjust the nuclear division equity ratio and RoE upward and make a corresponding balancing downward adjustment to the hydraulic division values in accord with Ms. McShane's estimates.[123]

GEC-Pembina-OSEA submitted if the Board does not set a separate cost of capital for each division, then the Board should direct OPG to use project-specific discount rates to reflect the relative risk level. GEC-Pembina-OSEA also suggested that in a future proceeding it might be appropriate to consider Mr. Chernick's proposal that deferral accounts be minimized, that the risk be reflected in the cost of capital, and that the added revenue be segregated to mitigate those risks if they arise.

Pollution Probe submitted:

> For purposes of cost allocation and rate design, separate and distinct costs-of-capital should be used since: 1) the nuclear assets are riskier than the hydro assets; and 2) OPG is already proposing different charges per MWh for its nuclear and hydro-electric assets [due to separate costs of production].[124]

Pollution Probe noted OPG's testimony that it did not object to this approach in principle, although it expressed concern as to whether such an approach was pragmatic in terms of the necessary calculations. Pollution Probe was of the view that the Board has the necessary evidence for such an approach and submitted that the evidence of Drs. Kryzanowski and Roberts should be accepted as they did determine separate capital structures for nuclear and hydroelectric as part of their analysis.

[123] GEC-Pembina-OSEA Argument, p. 7

[124] Pollution Probe Argument, p. 2.

SEC submitted that there would be value in setting separate capital structures in terms of reviewing investment decisions, but noted that the nuclear costs are not "real" in any event because the liabilities were shifted from OPG when it was created. SEC concluded that whether or not the Board sets separate structures,

> …it should direct OPG to maintain records of the relative costs of production and investment using separate equity ratios, and to carry out business case and similar forward-looking expenditure analyses using those technology-specific equity ratios.[125]

SEC submitted that the same ROE should apply to both, because the difference in risk is appropriately captured through the equity ratio.

CME submitted that there was no need to set separate capital structures for the nuclear and regulated hydroelectric when they are operated by a single business entity.

OPG responded that alleged benefits of technology-specific cost of capital either do not exist or are insignificant. For example, there is no evidence that a higher nuclear payment amount would impact operating decisions, and OPG already has a strong incentive to meet its production targets. Further, OPG's project specific risk analysis provides more rigour than a technology-specific discount rate would.

Board Findings

Although the regulated hydroelectric and regulated nuclear businesses are held by the same entity, in many respects they are operated quite separately. The rate base is separate; the production forecasts, capital budgets and OM&A forecasts have been established separately; the corporate cost allocation is done separately; and the payments are set separately. The two businesses also face different risks. The Board finds that there may be merit in establishing separate capital structures for the two businesses. It would enhance transparency and more accurately match costs with the payment amounts.

However, the Board also finds that the evidence in this proceeding is not sufficiently robust to set separate parameters at this time. Drs. Kryzanowski and Roberts developed separate estimates, but concluded with a combined recommendation. Ms.

[125] SEC Argument, p. 9.

McShane developed separate estimates, but cautioned that she was not as confident with the analytical results because they had been derived from working backwards.

The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs or the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs.

8.4.6 Should the Board adopt a formula to determine the ROE in future?

OPG proposed that the Board adopt an ROE adjustment formula for purposes of determining OPG's ROE in future proceedings. Specifically, OPG proposed adoption of the existing ROE adjustment formula outlined in the Board's report on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors.[126] That formula results in a 75 basis point change in ROE for every one hundred basis point change in the 30-year Long Canada Bond forecast.

OPG noted that it would seek a review of the formula returns if its business risk or access to capital changed materially and submitted that the adoption of a formula should not preclude it or another party from seeking a review. SEC supported the use of Board's formula approach to adjusting the ROE for years after 2009. CME also submitted that the formula approach was reasonable.

[126] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* December 20, 2006.

Board Findings
The Board agrees that adoption of a formula approach to setting the ROE is appropriate in the circumstances. The Board will adopt the existing ROE adjustment formula outlined in its report on cost of capital and 2nd generation incentive regulation for purposes of determining OPG's return on equity. The Board intends to examine whether the regulated hydroelectric and nuclear businesses should have separate capital structures. Setting the ROE through a formula is consistent with the Board's expectation that risk differences in the regulated businesses are appropriately addressed through the capital structure rather than the ROE.

8.5 Cost of Debt

8.5.1 Short-term debt

OPG forecast the cost of short term debt at 5.83% for 2008 and 5.98% for 2009.

AMPCO submitted that OPG's short-term rate on commercial paper of 8.4% appears excessive given the prime corporate paper rate was 3.17%. AMPCO also submitted that OPG's cost for Account Receivable securitization of 5.54% appears to be above current short-term rates. AMPCO submitted that a target cost of about 4% is more consistent with current conditions. SEC and CME supported AMPCO's submissions.

OPG responded that it uses commercial paper and Account Receivable securitization as its main source of short-term financing, but it also has a bank credit facility that has a forecast $1.4 million fixed cost. OPG noted that AMPCO had inappropriately rolled in this fixed cost with the forecast cost of commercial paper to derive its "implicit cost rate" of 8.4%. The rates on commercial paper are forecast to be 5.13% in 2008 and 5.32% in 2009, based a forecast of bankers' acceptances rate, the corporate spread and the dealer fee. OPG concluded its proposed short-term debt rate was reasonable as it is based on independent forecasts.

Board Findings
The Board will accept OPG's forecast cost of short term debt. The rates are based on independent forecasts. The Board finds that there is no evidence to support AMPCO's proposed level of 4%; that level is derived from an examination of then-current market conditions, not an assessment of conditions over the test period.

8.5.2 Long-term debt and the "other" long-term debt provision

OPG noted that its long-term debt outstanding with the OEFC is comprised of financing for unregulated projects, corporate debt of $3.2 billion and Niagara Tunnel project debt of $240 million. OPG added that about $1.6 billion in new borrowing is needed over the test period. OPG allocated its existing and planned corporate debt issues to regulated and unregulated operations using the ratio of *regulated* net fixed assets at December 31, 2007 to the *total* net fixed assets as per OPG's 2007 audited financial statements. (Project-related debt is assigned directly.) The forecast cost of planned new and refinanced corporate debt and project-related debt for 2008 and 2009 is based on the December 2007 Global Insight forecast of the 10-year Long Canada Bond plus an OPG credit margin of 130 basis points.

This allocation of OPG's existing and planned debt is not sufficient to equate OPG's proposed rate base with its proposed deemed capital structure. The "other" long-term debt provision – or "plug" – is the difference between the debt needed to equate the proposed deemed capital structure to the proposed rate base and the allocated debt. The interest rate attributable to this debt is the "average unhedged interest rate of new and refinanced debt issued each year for both corporate and project-related borrowing purposes."[127]

OPG forecast its long-term debt rates as 5.79% across the test period for its existing and planned long-term debt, and as 5.65% in 2008 and 6.47% in 2009 for its "other" long-term debt.

AMPCO submitted that the allocated existing long-term debt and the project-related debt were determined in a reasonable way and that the costs, being the actual rates paid, were acceptable. AMPCO submitted, however, that the proposed rates for new long-term debt of 5.65% in 2008 and 6.47% in 2009 are too high. AMPCO pointed out that OPG has proposed a credit risk spread of 130 basis points but the evidence is that OPG paid a spread of only 74.25 basis points on the Niagara Tunnel financing.

AMPCO submitted that applying a spread of 75 basis points to an average 10-year Canada rate for 2008 and 2009 of 4.25% would result in an interest rate of 5.0%. AMPCO recommended that a rate no higher than 5.5% be used for 2008 and 2009.

[127] OPG Argument in Chief, p. 37.

AMPCO further submitted that the Board's principle that in the case of long term debt held by an affiliate a utility shall only recoup the lower of the negotiated rate or market rate should apply to OPG as well. SEC and CME supported AMPCO's submissions.

OPG disagreed with AMPCO's forecast long term debt rate of 5.5%. OPG submitted that the 75 basis point spread available in June 2007 is not expected to be available under market conditions in the test period. The evidence is that spreads have widened and are expected to remain higher. OPG's most recent spread is 168 basis points, even higher than the spread of 130 basis points underpinning its proposed debt rate. OPG maintained that AMPCO's forecast 10 year Canada rate is also understated and that OPG's forecast was based on an independent forecast by Global Insight.

With respect to the affiliate argument, OPG responded that its arrangements with OEFC use an estimate of market rates derived through objective and independent information.

Energy Probe relied on the evidence of Dr. Schwartz and submitted that the "other" long-term debt provision should be accounted for as equity instead, and that the interest expense associated with the plug should be removed. Energy Probe submitted that using equity for the plug would result in an unacceptably low debt/equity ratio and that therefore the additional equity should be assigned a return of 0%. Energy Probe noted that this approach would not be necessary if the prescribed assets were transferred to a subsidiary with an approved capital structure.

Board Findings

The Board accepts OPG's proposed rates for 2008 and 2009 for existing and planned debt. The Board does not agree with AMPCO's conclusion that the cost of new debt should be set at 5.5%. The forecast costs of the planned debt are based on independent forecasts. The Board also accepts OPG's evidence that the credit spreads have widened and the spread available in June 2007 is not expected to be available in test period. Further, the Board accepts OPG's evidence that the OEFC rate is designed to be a market rate.

The Board finds, however, that the method for setting the cost of the "plug" debt is not appropriate. Rather than using the average of the unhedged cost planned debt, as OPG proposed, the Board finds that it is appropriate to use the average of the hedged cost of planned debt. This results in a forecast cost of debt for the "plug" which is consistent with the forecast cost of the allocated debt. On this basis, the cost of long-term "other" debt will be set at 5.63% for 2008 and 6.16% in 2009.

The Board will not adopt the approach suggested by Energy Probe. The Board has already noted that it did not rely on Dr. Schwartz's evidence.

The Board's decision with respect to the treatment of the unfunded nuclear liabilities for Pickering and Darlington will affect OPG's allocation of existing long-term debt and the level of "other" long-term debt. The Board does not have sufficient data to determine these impacts and therefore directs OPG to perform these calculations as part of the draft order.

9 DESIGN AND DETERMINATION OF PAYMENT AMOUNTS

9.1 Tax Losses and Rate Mitigation

OPG proposed to reduce the test period revenue requirement by $228 million because it "recognizes that the revenue requirement increase over the current payment amounts is significant and will have an impact on electricity consumers."[128] OPG characterized this mitigation as an acceleration of the application of regulatory tax loss carry forwards that OPG claimed existed at the end of 2007 and that would not be utilized in 2008 or 2009.

OPG said its regulatory tax losses at December 31, 2007 were $990.2 million. It forecast that $487 million of that amount would be used in 2008 and 2009, leaving $503.2 million available for subsequent periods.[129]

In addition to this mitigation, OPG decided not to recognize any provision for payments in lieu of income taxes (PILs) in the test period. PILs payments are calculated in accordance with federal and Ontario tax laws but are paid to the Ontario Electricity Financial Corporation. Assuming the Board were to approve its application as filed, OPG estimated that its regulatory taxable income, before consideration of the regulatory tax losses, would be $487 million for the two years ended December 31, 2009. At currently enacted tax rates, the PILs payments would be approximately $150 million for that period. The amount of PILs for the 21-month test period related to the prescribed facilities would be lower than that amount but would still be quite substantial.[130]

OPG calculated the accumulated "regulatory tax losses" of $990.2 million at the end of 2007 by computing the taxable income or loss since April 1, 2005 of the prescribed facilities (plus the Bruce lease). OPG indicated that the main reasons for the regulatory tax losses were:

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[128] Exhibit K1-1-2, page 1.

[129] Exhibit F3-2-1, Table 9.

[130] The Board was not able to calculate even a rough estimate of the amount of PILs for the test period for the prescribed facilities because regulatory taxable income as calculated by OPG includes taxable income related to OPG's Bruce lease. Also, the 2008 PILs amount provided by OPG is for a full year, not nine months.

- OPG made substantial tax-deductible contributions to the segregated nuclear funds (contributions during the period were $888 million, including a special one-time payment of $334 million in 2007 related to the Bruce facilities);
- the deduction in 2005 of $258 million in Pickering A return to service costs; and
- a loss before income tax from the prescribed facilities in 2007.

OPG referred to its accumulated loss carry forwards as “regulatory tax losses” to distinguish them from actual tax loss carry forwards that are recognized by the tax authorities. In fact, OPG’s witnesses noted that OPG did not have any actual tax loss carry forwards at the end of 2007. The benefit of all tax losses that were generated by the prescribed facilities during the period 2005 to 2007 were used to reduce PILs payable by OPG in respect of its unregulated operations. OPG’s witnesses also noted that in its consolidated financial statements for 2005 through 2007, OPG recorded the benefit of those “regulatory tax losses” in earnings; it did not credit any of the benefit of those losses to a deferral account to be used to reduce the payment amounts for the prescribed assets after April 1, 2008.

In its argument, OPG submitted that: “While an argument could be made that these tax losses belong to OPG and not to ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is appropriate that they be returned to ratepayers.”[131]

Only a few intervenors commented on OPG’s proposed mitigation and its elimination of a tax provision for 2008 and 2009. CCC, CME and SEC supported OPG’s approach. CCC and SEC noted that, absent the mitigating effect of the tax losses, the increase in payment amounts sought by OPG would be much higher than proposed in its application. CME supported OPG’s approach and noted that OPG was not obliged to allocate the benefit of the prior period tax losses to consumers.

Board Findings

OPG’s proposals to exclude a tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million mitigation amount are both linked to the $990.2 million of “regulatory tax losses” that OPG claims existed at December 31, 2007.

[131] OPG Argument-in-Chief, page 109.

OPG's tax calculations did not receive much scrutiny during this proceeding. Although intervenors supported OPG's proposals (or were silent on the issues), the Board is not convinced that OPG has taken the right approach to income tax issues in its application.

The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct. Reasons for the Board's concerns about OPG's treatment of taxes include:

- OPG's calculation of regulatory tax losses for 2005 to 2007 includes revenues and expenses related to OPG's Bruce lease. The Bruce stations are not prescribed facilities and OPG's Bruce lease is not regulated by the Board. In the Board's view, any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease.[132]
- OPG did not have any tax loss carry forwards at the end of 2007. OPG's witnesses confirmed that OPG was able to use the tax losses generated by the prescribed facilities for period 2005 to 2007 to reduce the income taxes that OPG would otherwise have paid in respect of its unregulated businesses. That is, the benefit of the tax losses related to OPG's regulated assets for 2005 to 2007 has already been realized by OPG.
- OPG witnesses confirmed that the benefit of the pre-2008 tax losses in respect of the regulated assets was recorded in OPG's audited financial statements in the form of a lower tax expense. Those witnesses also confirmed that OPG did not establish a deferral account at the end of 2007 to capture the tax benefits it claimed should be used to reduce regulatory taxes for 2008 and later periods in its application. The treatment of tax losses adopted in OPG's financial statements appears to conflict with the position taken in OPG's application to the Board.
- OPG stated that an argument could be made that the regulatory tax losses belong to OPG and not to customers since they arose in a period prior to Board regulation. Nonetheless, OPG submitted it was appropriate that the tax benefits be credited to customers although it offered no reasons why it was considered to be appropriate.

[132] As noted in Chapter 8, the Board has determined that revenues and costs related to the Bruce stations should be calculated for purposes of section 6(2)10 of Regulation 53/05 in accordance with GAAP (not regulatory accounting) and that a tax provision should be included in the Bruce costs.

Although the Board is not convinced that regulatory tax loss carry forwards existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all of the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.

The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss.

- In 2005, OPG deducted $258 million of Pickering A return to service costs in computing taxable income for that year. For accounting purposes, OPG recorded those costs in the PARTS deferral account. As noted in Chapter 7 of this decision, the remaining deferral account balance at December 31, 2007 of $183.8 million will be recovered through future payment amounts for the nuclear facilities. In the Board's view, the majority of the tax benefit realized by OPG in 2005 should be for the account of consumers given that the nuclear revenue requirement after 2007 will include $183.8 million to recover the deferral account balance.
- OPG's evidence indicated that in 2007 its regulated operations incurred an $84 million loss before income taxes (how much of that loss, if any, that relates to Bruce is unclear). It would appear that the operating loss in 2007 was borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.

The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods. The Board has therefore examined the proposed level of mitigation within the context of OPG's overall application.

With respect to 2008 and 2009, the Board is not able to agree, for the reasons outlined above, with OPG's position that "regulatory tax losses" permit it to eliminate an income tax provision. Because there is no evidence about the amount of pre-2008 tax benefits that appropriately should be carried forward to offset 2008 and 2009 PILs, the Board views OPG's proposal to eliminate an income tax provision in the test period as simply mitigation. OPG has effectively agreed to absorb whatever tax provision would otherwise be required for those years. The Board finds that this mitigation should be retained in OPG's calculation of the revenue requirement and payment amounts that flow from the Board's findings in this decision. That is, OPG should not include any tax provision for 2008 and 2009 in respect of the prescribed assets.

As for OPG's proposed $228 million mitigation amount, the Board also does not accept that there is any connection between that amount and any regulatory tax losses. OPG's offer of $228 million of mitigation was made in the context of the revenue requirement, before mitigation, shown in OPG's application. The revenue requirement that results from the Board's findings in this decision will be lower than that proposed by OPG. The Board concludes that it would be unreasonable to hold OPG to its original offer of mitigation. The mitigation amount of $228 million was about 22% of the $1,025.7 million revenue deficiency shown in OPG's application. The amount of mitigation the Board will require OPG to provide for the test period will be equal to 22% of the revenue deficiency calculated based on the Board's findings in the decision. The Board estimates that this amount will be about $170 million, compared to the $228 million in OPG's application.

In its next application for payment amounts for the prescribed assets, the Board will require OPG to file better information on its forecast of the test period income tax provision. To that end, the income tax provision for the prescribed facilities in future applications should not include any income or loss in respect of the Bruce lease. The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. That analysis should be based on the principle that if OPG is proposing that electricity consumers should bear a cost (or should benefit from revenues) they will receive the related tax benefit (or will be charged the related income taxes).

The Board also believes that its assessment of income taxes (and other elements of OPG's proposed revenue requirement) would be improved if OPG were to file a complete set of audited financial statements, including a balance sheet, for the prescribed facilities. The Board regulates the rates of a few utilities that are owned by entities that also own substantial unregulated businesses. Those regulated utilities do file separate audited financial statements as part of their applications. The Board directs OPG to file such audited financial statements for the prescribed facilities. Assuming that OPG's next application is filed in mid-2009, the Board expects OPG to file financial statements as at and for the year ended December 31, 2008.

9.2 Nuclear Payment Structure

9.2.1 OPG's fixed payment of $1.2 billion

OPG requested a change in the structure of payments for the nuclear facilities. The current nuclear payment amount is $49.50 per MWh, with OPG being fully at risk for outages at Pickering and Darlington. OPG proposed that the Board approve a fixed payment of $1,221.6 million (25% of OPG's proposed revenue requirement, net of variance and deferral account amortization), payable in equal monthly instalments. The balance of OPG's proposed nuclear revenue requirement would be recovered through a variable payment amount of $41.50 per MWh and a further $1.45 per MWh to cover clearance of variance and deferral accounts.

OPG argued that it should be awarded a significant fixed payment for the nuclear facilities because over 90 percent of nuclear costs are fixed, and because generators in Ontario and other jurisdictions receive some form of fixed payment. It also noted that the rates for utilities that provide regulated distribution services include a fixed component. OPG acknowledged that receiving a significant fixed payment for nuclear facilities would reduce OPG's risk. It submitted that the variable component of the proposed payment structure would still provide a strong incentive to maximize nuclear unit availability, avoid outages, and bring units back from an outage as quickly as possible.

Intervenors were split on the merits of OPG's proposal. CCC, PWU, SEC supported, or did not object to, a fixed component for nuclear payments. CCC submitted that it is more important to mitigate OPG's risk than to provide a meaningful incentive to avoid unscheduled outages. It recommended that the fixed portion of the nuclear payments be set at 50% of the revenue requirement. PWU and SEC supported OPG's proposed 25% fixed payment.

AMPCO, CME, Energy Probe, and GEC-Pembina-OSEA opposed OPG's proposal. AMPCO submitted that it would be inappropriate to relieve OPG of the incentive to maximize nuclear production that is inherent in the fully variable payment structure approved by the government in 2005. CME supported AMPCO's position and argued that if the Board were to approve any amount of a fixed payment for nuclear it should reduce the equity element of the deemed capital structure. GEC-Pembina-OSEA noted that several witnesses were asked to provide examples of generators receiving payments for non-production and that no precedents were provided.

Board Findings

The Board does not approve OPG's fixed payment proposal. The Board will continue the current 100% variable payment structure for nuclear output.

OPG's request to move away from a fully variable payment structure for the prescribed nuclear facilities does not appear to have been in response to a change in operational risk at the plants compared to the risk level in 2005. The Board could not identify any change in the operating environment that would dictate a need to revise the payment structure.

OPG's proposal would result in an increasing effective price per MWh for energy produced from the nuclear plants when OPG's production deteriorates. If OPG's nuclear production for the 21-month period ending December 31, 2009 were to exactly equal its forecast of 88.2 TWh, the proposed payment structure would result in revenue of $4,886.5 million, or $55.40 per MWh (excluding recovery of deferral and variance accounts). If, however, nuclear production is 5% less than forecast, the realized price under OPG's proposal would increase to $56.13 per MWh. The Board is not aware of any generator in Ontario that has such an arrangement, and OPG was not able to provide any relevant examples.

OPG stated that generators in Ontario and other jurisdictions receive some form of fixed payment. It did not provide examples. The Board is aware that generators in some jurisdictions receive fixed capacity payments as compensation for standing ready to generate when called on. As the Board understands those contracts, the fixed compensation paid to the generator is contingent on the generator actually being able to produce when called on. If the generator cannot produce when required, some of the fixed payments are clawed back. This is different from OPG's proposal, which would allow OPG to keep all of the fixed payment regardless of the level of its nuclear output.

The Board is also aware that some contracts between generators and the Ontario Power Authority provide for fixed monthly payments. As far as the Board is aware, generators with those contracts are deemed by the OPA to have operated, and deemed to have earned revenue that reduces the monthly fixed payment, when certain prices prevail in the gas and electricity markets. The fixed monthly payment is reduced by the deemed revenue whether or not the generator was able to generate when the OPA deems that it did so and earn revenue in the IESO market. In the Board's view, the payment structure in these contracts is not equivalent to OPG's proposed structure because the generator will lose part of its fixed payment if it is unable to operate when the OPA deems it to do so.

OPG likens its proposed fixed payment to monthly fixed payments charged to customers by regulated gas and electricity distribution companies. The Board does not accept OPG's comparison. It is true that most of the costs of regulated delivery utilities in Ontario and elsewhere are fixed. But, unlike OPG, those entities are essentially monopoly providers, with an obligation to serve, that must make sure their systems are available and capable of serving customers regardless of the level of customer demand any point. OPG is not seeking to mitigate the risk of fluctuating customer demand. Rather, it is seeking a fixed payment structure to mitigate the risk that OPG is unable to produce the amount of energy that it has forecast.

The Board believes OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast. This is the same position OPG would be in if the nuclear facilities were not regulated and were compensated through the hourly spot market or bilateral contracts.

9.2.2 Separate payment rider for deferral and variance account clearance

OPG said it favours recovering deferral and variance account balances through separate payment riders. It did not propose a separate rider for the hydroelectric accounts, because the amounts being cleared are small, but it did propose a rate rider of $1.45 per MWh to cover clearance of nuclear deferral and variance account balances.

No intervenor opposed establishing a separate rider for clearance of the nuclear accounts.

Board Findings
The Board approves the use of a rate rider to collect the amount of nuclear deferral and variance account balances approved for clearance in Chapter 7 of this decision.

9.3 Hydroelectric Payment Structure

The Board approves continuation of the current 100% variable payment structure for hydroelectric output. It also agrees with OPG that there should be no separate rate rider for recovery of hydroelectric deferral and variance accounts.

Chapter 3 sets out the Board's findings on the hydroelectric incentive payments.

10 IMPLEMENTATION

OPG proposed that its new payment amounts be made effective April 1, 2008 and that the retrospective amounts to April 1, 2008 should be recovered over the balance of the test period outstanding at the time of the issuance of the Board's Decision, through the monthly payments OPG receives from the IESO. The amount to be recovered for the retrospective period would be equal to the difference between the new payments approved by the Board, multiplied by actual production from the regulated facilities during that period, and the actual revenues received by OPG under the existing payment amounts, excluding any hydroelectric incentive revenues.

AMPCO supported OPG's proposal to recover the retrospective amounts back to April 1, 2008 using actual consumption. SEC proposed that the new payment amounts be effective April 1, 2008 except for that portion related to OPG's increased return on equity. No other intervenors made submissions on OPG's implementation proposal. OPG urged the Board to accept OPG's proposal for implementing the new payment amounts, and to reject SEC's proposal.

The Board has determined that the new payment amounts will be effective April 1, 2008 and that the shortfall for the period from April 1, 2008 to the implementation of the Board's order should be recovered over the balance of the test period.

The Board directs OPG to file with the Board, and copy all intervenors, a draft order which will include the final revenue requirement and payment amounts for the prescribed nuclear and hydroelectric faculties, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the amounts used.

With respect to the calculation of the payment amounts, OPG should assume that the IESO can start billing the new rates as of December 1, 2008 and that the payment amounts will be adjusted through the use of a rider to allow for the recovery of the 21 month revenue requirement over the 13 month period remaining in the test period.

With regard to the calculation of production for April 1, 2008 to November 30, 2008, OPG should use the monthly forecasts for both hydroelectric and nuclear production which underpinned its application. This will ensure that OPG remains at risk for its production forecast in the same way it would have been had the payment amounts been set on a prospective basis.

OPG is directed to file the draft order within 10 calendar days of the issuance of this decision. Intervenors shall have 7 calendar days to respond to the Company's draft order. The Company shall respond within 5 calendar days to any comments by intervenors.

DATED at Toronto, November 3, 2008

ONTARIO ENERGY BOARD

Original Signed By

Gordon Kaiser
Presiding Member & Vice Chair

Original Signed By

Cynthia Chaplin
Member

Original Signed By

Bill Rupert
Member

APPENDICES

TO

DECISION WITH REASONS

EB-2007-0905
ONTARIO POWER GENERATION INC.

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

Ontario Power Generation Inc. (OPG) filed its application for new payment amounts on November 30, 2007. On December 13, 2007 the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The Board issued Procedural Order No.1 on January 23, 2008 which established the procedural schedule for all events, including the hearing of OPG's request for an interim payment amount adjustment to take effect on April 1, 2008. Procedural Order No.1 also provided a draft issues list and a listing of the parties to the proceeding.

The procedural schedule included the following:

- Submissions on the issues list and the interim payment request were filed by February 1, 2008.
- The Issues Day/Interim payment hearing was held on February 6-7 2008.
- Interrogatories to OPG were filed by March 24, 2008. OPG responded to interrogatories by April 11, 2008.
- Intervenors and Board staff filed evidence by April 18, 2008.
- Interrogatories on intervenor and Board staff evidence were filed by April 23, 2008.
- Intervenors and Board staff filed responses to interrogatories by May 8, 2008.
- A technical conference was held on May 13 and 14, 2008.
- The oral Hearing commenced May 22, 2008

On February 7, 2008, the Board orally ruled on the matter of the issues list and OPG's request for an interim payment adjustment after hearing submissions from the parties, including OPG, the Association of Major Power Consumers of Ontario, the Schools

Energy Coalition, and Energy Probe, Power Workers Union and the Independent Electricity System Operator.

On March 20, 2008, April 9, 2008 and April 18, 2008 the Board issued Procedural Orders No. 2, No. 3 and No. 4 respectively which amended or extended the events schedule of the proceeding.

In response to OPG's request that certain interrogatory responses be treated confidentially, the Board issued Procedural Order No. 5 pursuant to the Board's Rules of Practice and Procedure and Practice Direction on Confidential Filings.

On July 29, 2008 the Board issued Procedural Order No. 6 which set out the timetable for the filing of cost claims by eligible intervenors in accordance with the Board's Practice Direction on Cost Awards.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Donna Campbell Richard Battista Russell Chute Chris Cincar Russell Holden
Ontario Power Generation	Michael A. Penny Josephina Erzetic Andrew Barrett Barbara Reuber
Association of Major Power Consumers in Ontario	Mark Rodger Adam White Wayne Clark Tom Adams Lawrence Murphy
Canadian Manufacturers & Exporters	Peter Thompson

Consumers Council of Canada	Robert Warren Julie Girvan
Energy Probe Research Foundation	Peter Faye David MacIntosh Lawrence Schwartz Norman Rubin Kimble Ainslie
Green Energy Coalition	David Poch
Pollution Probe Foundation	Murray Klippenstein Basil Alexander Jack Gibbons
Power Workers Union	Richard Stephenson John Sprackett Judy Kwik Alfredo Bertolotti
School Energy Coalition	Jay Shepherd Bob Williams Mikaela Cameron Rachel Chen
Vulnerable Energy Consumers Coalition	Michael Buonaguro Bill Harper

WITNESSES

The following OPG employees appeared as witnesses.

David Halperin	Director, Business and Financial Planning, Corporate Finance
Fred Long	Vice President, Financial Planning
Colleen Sidford	Vice President, Treasurer
Joan Frain	Manager, Water Policy and Planning Water Resource Division
Don B. Gagnon	System Support Manager Niagara Plant Group

Mario Mazza	Director, Business Support and Regulatory Affairs Hydro Business Unit
Mark Shea	Asset and Technical Services Manager Ottawa/St Lawrence Plant Group
Ken Lacivita	Director, Trading and Origination Energy Markets
Robert Boguski	Senior Vice President, Business Services and Information Technology
John Mauti	Director, Nuclear Reporting
Paul Pasquet	Deputy Site President, Pickering B
Bill Robinson	Senior Vice President, Nuclear Programs and Training
Dana Letts	Outage Program Manager Nuclear Programs and Training
Vincent Gonsalves	Director, Business Planning
Michael Allen	Director, Work Management
Michael McFarlane	Outage Manager Darlington
Robert Latimer	Department Manager, Strategic Planning, Pickering A
Mark Arnone	Director, Projects and Modifications
Randy Leavitt	Director, Investment Management
Craig Sellers	Chief Engineer, Nuclear New Build
Laurie Swami	Director of Licensing, New Generation Development
Mario Cornacchia	Director, Commercial Services Inspection and Maintenance and Commercial Services
Dennis Dodo	Controller, Inspection and Maintenance Services
Bob Morrison	Vice President, Engineering and Modifications and Chief Nuclear Engineer
Neil Brydon	Manager, External Reporting and Policy

Angelo Castellan	Director, Nuclear Waste Business Support
Robin Heard	Vice President, Financial Services
Lorraine Irvine	Vice President, Compensation and Benefits
Tom Staines	Controller, Corporate Accounting Finance
Andrew Barrett	Vice President, Regulatory Affairs and Corporate Strategy
Lubna Ladak	Manager, Regulatory Finance
Sean Granville	Director, Nuclear Programs

OPG also called the following expert witness: Kathleen McShane of Foster Associates Inc.

The intervenors and Board staff called the following expert witnesses:

- Laurence Booth of the University of Toronto appearing for VECC and CCC
- Paul Chernick of Resource Insight Inc. appearing for GEC
- A.J. Goulding of London Economics International appearing for Board staff
- Lawrence Kryzanowski of Concordia University and Gordon Roberts of York University appearing for Pollution Probe
- Lawrence Murphy of Henley International Inc. and Tom Adams appearing for AMPCO
- Lawrence Schwartz of York University appearing for Energy Probe

APPROVALS SOUGHT BY OPG IN EB-2007-0905

(Source; Exhibit A1- 2- 2)

- An order from the OEB declaring OPG's payment amounts interim as of April 1, 2008.

- An order from the OEB establishing interim payment amounts of $35.35/MWh for the
  - output of Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station,
  - DeCew Falls I, DeCew Falls II, and R.H. Saunders Generating Stations (the "regulated
  - hydroelectric facilities") and $53.00/MWh for the output of Pickering A Generating Station, Pickering B Generating Station, and Darlington Generating Station (the "nuclear
  - facilities") effective April 1, 2008. During the period of interim rates, OPG expects to
  - retain the hydroelectric incentive mechanism under O. Reg. 53/05 under which the
  - output from the regulated hydroelectric facilities in excess of 1900 MWh in any hour receives market price.

- The approval of a revenue requirement of $1283M for the regulated hydroelectric facilities and a revenue requirement of $5152M for the nuclear facilities for the period of April 1, 2008 through December 31, 2009 (the "test period") as set out in Ex. K1-T1-S1.

- The approval of a rate base forecast of $3886M and $3870M for the regulated hydroelectric facilities for the years 2008 and 2009, respectively and $3515M and $3484M for the nuclear facilities for the years 2008 and 2009, respectively, as summarized in Ex. B1-T1-S1. OPG's request for this approval is supported by an examination of the asset and liabilities values and other related matters in the 2006 audited financial statements pursuant to paragraph 6 (2) 5 of the Regulation and asset forecast as found in Exhibit B.

- Approval of a capital budget for the regulated hydroelectric facilities for the test period, as presented in Ex. D1-T1-S1 and for the nuclear facilities for the test period, as presented in Ex. D2-T1-S1.
- Approval of a production forecast of 31.5 TWh for the test period for the regulated hydroelectric facilities and 88.2 TWh for the test period for the nuclear facilities. Production forecast is presented in Ex. E.

- Approval of a deemed capital structure of 42.5 percent debt and 57.5 percent equity and a combined rate of return on rate base of 8.48 percent and 8.56 percent for 2008 and 2009, respectively, including a rate of return on equity (“ROE”) forecast of 10.5 percent, as presented in Ex. C1-T1-S1 and Ex. C1-T2-S1.

- Approval of the automatic adjustment mechanism to adjust the rate of return on common equity in future periods, as discussed in Exhibit C1-T1-S1.

- Approval of a payment amount for the regulated hydroelectric facilities of $37.90/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the “hourly volume”) for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator (“IESO”) – administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG’s revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO - administered market. The payment amount for the regulated hydroelectric facilities is set out in Ex. K1-T2-S1 and the design of the regulated hydroelectric payment amount is set out in Ex. I1-T1-S1.

- Approval of a payment amount for the nuclear facilities, of $58.2M/month plus $41.50/MWh, as set out in Ex. K1-T3-S1.

- For the nuclear facilities, approval for recovery of $342M from the variance and deferral accounts using a payment rider of $1.45/MWh, as presented in Ex. J1-T1-S1 and Ex. J1-T2-S1. For the regulated hydroelectric variance account, recovery of $0.7M by adding this amount to the revenue requirement used to calculate the hydroelectric payment amount, as presented in Ex. J1-T2-S1 and Ex. K1-T1-S1.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:

  – A variance account to record the deviation from forecast revenues associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions.

  – A variance account to record the deviation from forecast revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.

  – A variance account to record the deviation from forecast non-capital costs associated with work to increase capacity or to refurbish a generation facility. The account would include deviations in costs associated with the potential refurbishment of Pickering B and Darlington Generating Stations.

  – A variance account to recover the deviation from forecast non-capital costs for planning and preparation for the development of proposed new nuclear generation facilities.

  – A variance account to record the deviation between actual and forecast nuclear fuel costs.

  – A variance account to record the customer's share of revenues from energy sales to Hydro Quebec as a result of segregated mode of operation at R.H. Saunders, and from water transactions at the regulated hydroelectric facilities.

  – A variance account to record the deviation between actual and forecast pension and other post-employment benefit expenses related to changes in the discount rate.

  – A deferral account to record non-capital costs associated with the planned return to service of units at the Pickering A Generating Station.

- A deferral account to record the revenue requirement impact of the change in the nuclear decommissioning liability arising from the December 2006 approved reference plan as defined in the Ontario Nuclear Funds Agreement.

- A variance account to capture the tax impact of changes in tax rates, rules and assessments.

DECISION ON INTERIM PAYMENTS - EB- 2007- 0905

Source: EB-2007-0905 Transcript dated February 7, 2008 p.p. 111-118

See following pages:

here, of course, is that we have two, at least two, of the significant intervenors who represent consumers - that is, CCC and VECC - acknowledging, in this case, that it does make sense to think about some rate smoothing.

MS. CHAPLIN: But I guess in this case we have residential consumer groups perhaps agreeing with that --

MR. PENNY: Yes.

MS. CHAPLIN: -- but industrial consumer groups retaining that position that it is better to under-collect than to over-collect?

MR. PENNY: Absolutely. No doubt about it.

MS. CHAPLIN: Okay, thank you.

MR. KAISER: Thank you. We will come back at 2:15.

--- Luncheon recess taken at 12:58 p.m.

--- On resuming at 2:45 p.m.

MR. KAISER: Please be seated.

DECISION:

MR. KAISER: The Board heard submissions this morning from a number of interested parties with respect to an application by Ontario Power Generation for interim rates. This relates to the application OPG filed on November 30th under section 78.1 of the Ontario Energy Board Act for approval of increases in payment amounts for the output of certain next generation facilities effective April 1st, 2008.

In particular, OPG seeks two Interim Orders. The first Order would make its current payment amounts interim, effective April 1st, 2008. Secondly, they seek an Interim

Order increasing OPG's payment amounts on an interim basis to $35.35 per megawatt hour for hydro-electric production, and $53 per megawatt hour for nuclear production.

There are two questions before us. The first is, does the Board have jurisdiction in this case to issue these types of orders? And the second is, if we do have the jurisdiction, should we exercise that jurisdiction, and to what extent?

Dealing with the first question, first. Mr. Penny, on behalf of OPG, has referred the Board to a number of cases with respect to the issuance of interim orders throughout the country. It is useful in the context of this case to identify the essential characteristics of an Interim Order. This is at paragraph 28 of his factum.

First, an Interim Order does not require any decision on the merits of an issue. That will be settled in the final decision. The purpose of an Interim Order is to provide relief for any deleterious affects caused by the length of the proceedings. Secondly an Interim Order is temporary. It can be changed retrospectively once the final determination is made. Thirdly, an Interim Order assumes and requires that a final order will be made. One initiates the process and the other ends it, a point that Mr. Penny made on a number of occasions.

Mr. Penny has also referred us to the Supreme Court of Canada decision in the Bell Canada case where the Court stated:

"Traditionally, such interim rate orders dealing in interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceeding.

"Such decisions are made in an expeditious manner on the basis of evidence that would often be insufficient for the purposes of a final decision. The fact that an order does not make any decision on the merits of an issue to be settled in the final decision and the fact that its purpose is to provide temporary relief against deleterious effects caused by the duration of the proceedings are essential characteristics of an interim order."

There is no question that section 21(7) of the OEB Act grants the Board clear authority to issue interim orders. It has done so on a number of occasions. Mr. Penny referred to a number of those decisions including decisions involving IESO, the OPA, and various gas companies.

Of particular interest here is whether a reading of section 78.1 of the Act leads to a conclusion that the Board cannot or should not issue an interim order in this case.

Section 78.1(2)(b) provides, in relevant part, that the payment amount shall be the amount determined:

"in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the latter of

(i) the date prescribed for the purpose of this subsection; and

(ii) the effective date of the Board's first Order under this section in respect to the generator.

O. Reg 53/05 specifies the amount, for the purposes of section 78.1(2) that the IESO is required to pay OPG for the output from the prescribed facilities from April 1st, 2005 to the later of:

(i) March 31st, 2008; and

(ii) the day before the effective date of the Board's first Order in respect of Ontario Power Generation Inc.

Now, much was made of the fact as to whether a first order in this section meant an Interim Order or whether it meant a Final Order.

It was Mr. Penny's position that it meant a Final Order.

Mr. Faye, in his submissions on behalf of Energy Probe, argued that if we were to look, for instance, at Regulation 62.5, that this Regulation required the Board to accept certain amounts and take certain steps in a very distinct fashion. He argues that if a first order was an Interim Order (which chronologically it might seem to be), some real complications would result and leads to the conclusion that an interim order should not be granted.

Having listened to the submissions of all of the parties, the Board is of the view that there is nothing in the language of section 78.1 or section 4 of Ontario Regulation 53/05 that removes the power of the OEB to set interim payment amounts, nor can that restriction be implied as necessary to the operation of the legislative scheme. In fact, the language of these provisions recognizes that when an OEB order concerning payment amounts is made, may well be different from the effective date of that order. This supports the interpretation that the OEB's power to make interim orders applies to payment amounts under section 78.1.

An Interim Order is not necessarily a first order within the meaning of the Act. A reasonable interpretation of the words "first order" is that it is a Final Order which determines what might be described as the first rates set definitively by the Board and not prescribed by Regulation. An Interim Order can by its nature be time limited and subject to whatever is determined in the Final Order. Section 78.1 does no more than establish that the payment amounts are as prescribed by regulation until the latter of March 31st, 2008 and the effective date of the OEB's first order. The language of section 78.1 does not suggest that the OEB's power under section 21.7 to issue interim orders is in any way limited or abrogated other than by the limitation that any such order could not purport to have an effective date before April 1st, 2008.

The object of the Act and the intention of the legislature is clear. In our view, the clear purpose of section 78.1 of the Act and section 4 of the Regulations is to fix the OPG payments for three years until March 31st, 2008 and to leave to the OEB thereafter the task of determining payment amounts that are just and reasonable in accordance with the regulations.

In summary, the ability to fix just and reasonable payment amounts would be compromised, in our view, if the Board can only take action after a full and final hearing. The power to make interim orders is clearly confirmed by the Act and is necessary for the protection of both customers and generators. This power can be abrogated only by the clearest statutory language. There is nothing in section 78.1 that supports that conclusion.

This, then, leads us to the second aspect of this motion. This is the Applicant's request, in the first instance, that the existing or current payment amounts be declared interim effective April 1st, 2008. And in the second case that a Interim Order be issued, increasing those payment amounts, on an interim basis, to the amounts I described earlier, namely $35.35 per megawatt hour for hydroelectric production and $53 per megawatt-hour for nuclear production.

We will consider the first aspect first; whether the existing payment amounts should be declared interim effective April 1st, 2008. The Board agrees that that should be the case and an Order will issue to that effect.

We see no harm resulting to any party as a result of such an Order. It is not unusual for such Orders to issue.

It preserves the ability of the Board to set rates effective April 1st, 2008. And the ability of the utility to recover any ultimately determined revenue deficiency from that date.

That leads us to the second question; whether the payment amount should be increased to the requested amount on an interim basis effective the same date, April 1st, 2008.

This application is denied. The requested amount, which I have described earlier, is said by the Applicant to be 50 percent of the amount claimed in its Application. This calculation is set out at paragraph 108 of the Applicant's Factum. It refers in part to the cost of capital. Instead of claiming the whole amount they would receive if they receive an ROE of 10.5 percent, they have reduced that to Hydro One's 8.34 percent ROE. They also added two recovery amounts, 85.3 million for the nuclear liability deferral account, and another 67.7 million for recovery of specified deferral and variance accounts balance. The latter two accounts are accounts where recovery is required by the Regulation.

OPG has claimed a total revenue deficiency of some $760 million accumulating, they say, at the rate of about $39 million a month.

The Board is concerned, at this point, with granting the requested payment increase. The main argument was not financial harm, which we often hear in these cases and is often the basis for interim rate increases. Rather, OPG seeks rate smoothing to avoid rate shock to consumers.

Of course, any concern with rate shock assumes that there will be some rate increase; otherwise, smoothing is not necessary. Mr. Stephenson, on behalf of his client, the Power Workers' Union, supported the applicant and said, "we know some increase is coming, and we might as well start to absorb some of it sooner rather than later".

I should add that the applicant was supported by three consumer groups in this regard, the Consumers Council of Canada, VECC and Power Workers' Union, but was opposed by three other consumer groups, the School Energy Coalition, AMPCO and Energy Probe. So the consumer groups were divided on the issue.

In the end, the Board believes that if smoothing is the objective and if smoothing is required, at it can be achieved prospectively. It is not necessary to do that by early rate implementation.

We also note the concerns of AMPCO, that some of the increase sought relates to increased cost of capital, particularly return on equity. They expect this will be a contentious issue. AMPCO was concerned that the Board not be seen to prejudge that issue at that point.

That completes the Board's ruling in this matter. Any questions?

MR. PENNY: No, thank you.

MR. KAISER: Thank you. Thank you, gentlemen, ladies.

--- Whereupon the hearing adjourned at 3:02 p.m.

Excerpt: Section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O.1998, c.15 (Schedule B).

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, \$33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

   (i) March 31, 2008, and

   (ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.
2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

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Memorandum of Agreement

Source: EB-2007-0905 Exhibit A1-4-1 Appendix B

Filed: 2007-11-30
EB-2007-0905
Exhibit A1-4-1
Appendix B

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of

Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. <u>Financial Framework</u>

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. <u>Communication and Reporting</u>

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. <u>Review of this Agreement</u>

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:

Jake Epp
Chairman
Board of Directors

On Behalf of the Shareholder:

Her Majesty the Queen in Right of
the Province of Ontario as
represented by the Minister of Energy,
Dwight Duncan

DECISION **NSUARB-NSPI-P-888**
2008 NSUARB 140

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **Nova Scotia Power Incorporated** for approval of certain Revisions to its Rates, Charges and Regulations

BEFORE: Peter W. Gurnham, Q.C., Panel Chair
Roland A. Deveau, LL.B., Member
Kulvinder S. Dhillon, P. Eng., Member

COUNSEL:

NOVA SCOTIA POWER INCORPORATED
René Gallant, LL.B.
Terry Dalgleish, Q.C.
Nicole Godbout, LL.B.

AFFORDABLE ENERGY COALITION
Susan Nasser

AVON VALLEY *et al.*
Robert G. Grant, Q.C.
Nancy G. Rubin, LL.B.
Mark Freeman, LL.B.

SMALL BUSINESS ADVOCATE AND CONSUMER ADVOCATE
John P. Merrick, Q.C.
William L. Mahody, LL.B.

HALIFAX REGIONAL MUNICIPALITY
Martin C. Ward, Q.C.
Angus Doyle

MUNICIPAL ELECTRIC UTILITIES
OF NOVA SCOTIA CO-OPERATIVE
Don Regan

NDP CAUCUS OFFICE
Graham Steele, MLA

PROVINCE OF NOVA SCOTIA
(Department of Energy)
Stephen T. McGrath, LL.B.
Scott McCoombs
Richard Penny

NEWPAGE PORT HAWKESBURY LIMITED and
BOWATER MERSEY PAPER COMPANY LIMITED
George T. H. Cooper, Q.C.
David S. MacDougall, LL.B.
James MacDuff, LL.B.

QUETTA INC.
John H. Reynolds

HEARING DATES:	September 15, 17 & 18, 2008
FINAL SUBMISSIONS:	September 25 and 29, 2008
LIST OF INTERVENORS:	APPENDIX A
BOARD COUNSEL:	S. Bruce Outhouse, Q.C.
DECISION DATE:	**November 5, 2008**
DECISION:	**Settlement Agreement approved; Average rate increase of 9.3% effective January 1, 2009.**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] This decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") on September 15, 17 and 18, 2008, in the matter of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility") for approval of revisions to its Rates, Charges and Regulations.

[2] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2007, served approximately 478,038[1] customers, including six municipal electric utilities.

[3] In its application, dated May 27, 2008, NSPI requested an increase in rates in order to meet its estimated revenue requirement increase for 2009 of $132.5 million. NSPI used 2009 estimated costs as a 'test year' for the purpose of determining the additional revenue it required and the corresponding rate increases for its various customer classes should its application be approved. The proposed overall average rate increase was 11.9%, with certain customer classes subject to a higher or lower rate increase. For example, residential customers would see a 12.1% increase with increases ranging from 9.6% to 17.4% for all other metered classes of customers.

[4] The public hearing was duly advertised in accordance with sections *64* and *86* of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows:

[1] NSPI 2007 Annual Report, p. 62

Approval of schedule of rates and charges of utility

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Filing with Board

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.

Notice of hearing of application for rate changes

86 Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

[5] A total of 31 formal intervenors responded to NSPI's application. A number of these parties (identified in Appendix A attached) were represented at the hearing by counsel. The Nova Scotia Department of Energy (the "Province"); the Small Business Advocate and Consumer Advocate (the "CA"); Avon Valley *et al.* ("Avon"), whose Counsel represented 17 intervenors; NewPage Port Hawkesbury Limited and Bowater Mersey Paper Company Limited ("NPB"); Halifax Regional Municipality ("HRM"); Affordable Energy Coalition ("AEC"); the NDP Caucus office; the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); and Quetta Inc., all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's application.

2.0 BACKGROUND

[6] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the Province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the Province. The Board regulates NSPI in the public interest on a cost-of-service basis. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental rate-making principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates,** sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>   (a) in the control of the total amounts of service supplied by the company;

> (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
>
> [Board Decision, March 31, 2005, p. 14]

[7] The Board continues to make its decisions in accordance with the *Act*, and the principles noted above.

[8] At the commencement of the public hearing on September 15, 2008, NSPI notified the Board it had reached a Settlement Agreement (the "Agreement"), which was endorsed by most of the formal intervenors, including all who filed evidence in this proceeding. The Board adjourned the hearing to provide an opportunity to all parties to review the document, and when the hearing reconvened on September 18, 2008, additional specific information regarding the impact of the Agreement (i.e., the revenue to cost ("R/C") ratios and proposed rate increases) was filed by NSPI[2].

3.0 SETTLEMENT AGREEMENT

3.1 The Board's approach with respect to this Settlement Agreement

[9] Several parties discussed the approach the Board should take in considering the Agreement. NSPI, in its final submission, stated:

[2] Exhibit N-69

> The Board must consider whether the adoption of the Settlement Agreement is in the public interest. The Board has recently considered the public interest in its approval of the FAM Settlement Agreement (P-887) and of the DSM Settlement Agreement (P-884).
>
> In *re Sale of Assets of Kentville Electric Commission* [1998] N.S.U.A.R.B. No. 100, Board Counsel made submissions on the issue of public interest, which the Board quoted in its decision. The Board has dealt with "public interest" in earlier decisions, but because of the broad nature of that concept has not formulated a precise definition. Essentially, the Board must consider broadly the effect of the request, and weigh the benefits and risks to both the utility and customers.
>
> [NSPI Closing Submission, pp. 1-2]

[10] Avon *et al.* made the following observation:

> The process leading up to a settlement involved compromises by all participants. The Board should feel confident that a Settlement Agreement which has the support of all customer classes - from the largest electrical consumers to the residentials should be given significant weight. The diversity of interests is not only as between NSPI and its customers but also among customer classes as well. Despite these competing interests, the parties were able to arrive at a negotiated settlement respecting both the revenue requirement and cost allocation.
>
> [Avon *et al.* Final Submission, p. 1]

[11] The CA, in a thoughtful generic submission on settlement, stated as follows:

> A settlement is a consensual solution. It of necessity involves a compromise between the optimal outcomes sought by the contending parties. The CA was tempted to reject the settlement and leave it to the UARB to determine the outcome after a contested hearing. That would have the advantage of the public seeing the requested increase resisted vigorously with the result being imposed by the UARB. There would be no suspicions of "deals" or of NSPI somehow manipulating to achieve its profit-seeking goals. There is some merit to forcing a contested hearing when the increase being sought is high. But if the most likely outcome of a contested hearing would be no better than could be achieved by negotiation and consensus, common sense mandates that the consensus be put to the UARB for review and possible acceptance.
>
> There is the further consideration that ideally NSPI and its customers can move to a relationship of complete disclosure and candor that will allow more matters to be resolved by discussion and consensus with a diminished need for expensive and contentious adversarial hearings. The CA does not say that relationship has happened, but progress is being made.
>
> [CA Final Submission, p. 3]

[12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.

[13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

[14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.

[15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.

[16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.

[17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.

[18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.

3.2 The Settlement Agreement in the present case

[19] The Agreement reads as follows:

2009 General Rate Application Settlement Agreement

Whereas Nova Scotia Power Inc (NSPI) filed an Application for a General Rate Increase with the Nova Scotia Utility and Review Board (UARB) on May 27, 2008, proposing an increase in revenue requirement of $132.5 million and seeking an average rate increase of 11.9% effective January 1, 2009 (the "Application");

And whereas NSPI, New Page Port Hawkesbury Ltd. and Bowater Mersey Paper Company Ltd. (NPB), the Avon group (Avon), the Consumer Advocate (CA), the Municipal Electric Utilities of Nova Scotia Cooperative (MEUNSC) and the Department of Energy (DOE) have worked together with staff and consultants to the UARB to develop and implement a Fuel Adjustment Mechanism (FAM) for NSPI;

And whereas the Parties to this Agreement agree that the FAM will be ready to operate effective January 1, 2009 and NSPI will be ready for the FAM; And whereas NSPI is forecasting revenue requirement increases in the 2009 test year consisting primarily of fuel expenses and other costs, which have been disclosed in the Application and examined during the course of the Application pre-hearing discovery processes;

And whereas the Parties desire to resolve the Application, and to continue to work collaboratively to accomplish objectives that will benefit customers over the long term;

The signatories to this agreement hereby agree:

FAM and Fuel Related Items:

1. The FAM, including supporting documentation, is substantially complete, and there are no remaining issues that would cause any of the Parties to object to the operation of the FAM on January 1, 2009.

2. The Parties request that the UARB approve the FAM to commence on January 1, 2009, as an outcome of this General Rate Application and in lieu of the formal schedule for approval previously established by the UARB in its December 10, 2007 Decision.

3. The Parties will finalize the FAM documentation and NSPI will file a final proposed Tariff and Plan of Administration no later than October 15, 2008 for UARB approval. Any matters regarding the FAM documentation which remain outstanding between the Parties will be determined by the UARB, and Parties other than NSPI, including UARB consultants, shall file any comments on outstanding issues with the UARB by October 22, 2008. Other aspects of FAM implementation, as directed by the UARB in its December 10, 2007 Decision, will continue throughout 2008.

4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.

5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.

6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.

7. The Parties agree that for the purposes of calculating the FAM incentive, the Base Cost of Fuel in rates will be assumed to be re-set at $590 million (as adjusted per Schedule 2, Appendix A of the FAM Plan of Administration to calculate an average cost per MWh, of $45.95 per MWh, and for each customer class) until the Base Cost of Fuel is again actually re-set, either pursuant to the FAM or during a future General Rate Application.

8. The Parties acknowledge and advise the UARB that an outcome of delayed recovery of a portion of NSPI's forecasted increased 2009 fuel costs described in paragraph 5 above is that the first FAM adjustment will most likely result in an increased recovery from customers beginning on January 1, 2010.

Other Costs and Items:

9. Beginning on January 1, 2009, the revenue for rate setting purposes for each customer class shall be as set out in Schedule 1 attached. The increase in revenue requirement will be $104.2 million, comprised of the $75 million noted in paragraph 4 and the $29.2 million noted in paragraph 10.

10. NSPI has advised the Parties and the UARB of non-fuel cost increases in the 2009 test year. The Parties agree to an increase in revenue requirement of $29.2 million to recover non-fuel cost increases and which increase is in addition to the fuel cost recovery provided above in paragraph 4.

11. The non-fuel increase incorporates reductions in NSPI's forecasted 2009 revenue requirement, compared to the Application, in the non-fuel related areas of the Application, including a reduction of $3.4 million in Vegetation Management costs, extension of the amortization period for Demand Side Management costs to six years to reduce revenue requirement by $3.6 million, removal of the 2008 fuel deferral from rate base as noted above in paragraph 6, and other OM&G and rate base reductions in the total amount of $6.0 million. This increase incorporates the ROE reduction requested in the Application. NSPI's proposed rates and proof of revenue for 2009 shall be as set out in Schedule I attached.

12. The revenue requirement increase will be allocated proportionately to each customer class, on an "across the board" basis, with revenue from each customer class increasing by the same percentage as other customer classes in order to recover in total the increased revenue requirement.

a. This is a one time allocation approach and does not create any precedent for future cases, including the adjustments noted below in sub-paragraphs b) and c).

b. Subsequent to such allocation, the Unmetered class rate and revenue will be reduced to the point where the Unmetered class revenue to cost ratio would be 1.00. This reduction in revenue will not be recovered from other customers.

c. A further adjustment will be made so that the group of Large Industrial Class customers who receive the Interruptible credit will see the same average rate increase as other classes. This will be accomplished by applying a temporary equalization adjustment. The adjustment will be cost neutral to other classes and will not affect the interruptible credit value.

13. The Parties also acknowledge that their agreement to the non-fuel average revenue increase should not be construed as an acceptance by any of the Parties of any allocation or amortization of future DSM or other costs to such Parties, and that the average increase in this Agreement shall not be adjusted on account of any future DSM or other decision by the UARB. In particular, the Parties may take any position on DSM cost recovery and allocation in respect of post-2009 DSM programs and costs.

14. Unless revised by the terms of this Agreement, all other aspects of NSPI's Application are adopted for the purposes of this Agreement only, and this Agreement does

not preclude NSPI or any of the other Parties from taking any positions in future regulatory proceedings or otherwise.

15. NSPI will provide a Cost of Service Study in electronic form to Parties, subject to appropriate confidentiality undertakings and on condition that the model not be used for commercial purposes. Such information shall likewise be available in electronic form for subsequent proceedings.

All of which is hereby agreed this 15th day of September, 2008.

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 1)	Current Revenue	Proposed Revenue	Revenue Increase	% Revenue Increase	R/C Ratios
ABOVE-THE-LINE CLASSES					
Residential	**$496.3**	**$542.8**	**$46.5**	**9.4%**	**98.9%**
Commercial					
Small General	$30.7	$33.6	$2.9	9.4%	102.3%
General Demand	$252.8	$276.6	$23.7	9.4%	107.2%
Large General	$34.8	$38.0	$3.3	9.4%	98.7%
Total Commercial	**$318.3**	**$348.2**	**$29.8**	**9.4%**	**105.7%**
Industrial					
Small Industrial	$23.9	$26.1	$2.2	9.4%	102.0%
Medium Industrial	$48.6	$53.2	$4.6	9.4%	100.8%
Large Industrial	$65.0	$71.1	$6.1	9.4%	97.5%
ELI 2P-RTP	$119.2	$130.3	$11.2	9.4%	91.0%
Total Industrial	**$256.6**	**$280.6**	**$24.1**	**9.4%**	**95.3%**
Other					
Municipal	$16.1	$17.6	$1.5	9.4%	99.8%
Unmetered	$24.0	$25.2	$1.2	5.0%	100.0%
Total Other	**$40.1**	**$42.8**	**$2.7**	**6.8%**	**99.9%**
Total Above-the-line classes	**$1,111.3**	**$1,214.5**	**$103.2**	**9.3%**	**99.9%**
Below-the-line	**$21.2**	**$22.1**	**$0.9**	**4.5%**	
Exports	**$4.6**	**$4.6**	**$0.0**	**0.0%**	
Miscellaneous	**$14.2**	**$14.7**	**$0.4**	**2.9%**	
Total Revenue	**$1,151.3**	**$1,255.8**	**$104.5**	**9.1%**	

[Exhibit N-69]

[20] The Agreement presented to the Board has the support of representatives of all of the customer classes including the domestic class. The Board's consultants Dr. John Stutz and Mr. John Antonuk recommend its approval.

[21] As noted by NPB, not only were most of the parties to the Agreement represented by experienced counsel, they also had experienced expert advisors with respect to the various issues before the Board including fuel, rates, OM&G, etc.

[22] For the reasons explained below, and having concluded that it is in the public interest, the Board approves the Agreement.

4.0 FUEL

4.1 Fuel Cost

[23] NSPI, in its application, stated that:

> Current rates include fuel and purchased power expenses of $470 million. The test year fuel cost requested in this Application is $559.5 million, or $89.5 million higher than the amount included in the 2007 Compliance Filing (2007C)...
>
> [Exhibit N-1(a), p. 9]

[24] The majority of intervenors initially questioned NSPI's estimate of 2009 fuel cost on grounds such as generation cost allocation, load forecast, prioritization of generation facilities, currency exchange, Cost of Service Study, etc.

[25] Liberty, however, in their evidence recommended that:

> NSPI's fuel expense estimate for the Rate Year (2009) as filed should be used to set base rates, because its actual costs, even after considering appropriate offsets are reasonably certain to equal or exceed the amount set forth in the filing...
>
> [Exhibit N-30, pp. 6-7]

[26] On September 5, 2008, NSPI filed an update to its 2009 fuel cost:

> This forecast uses the fuel forecasting methodology collaboratively developed by NSPI, Liberty Consulting Group, NPB and other Intervenors in the FAM process. An adjustment was made to the FAM methodology to reflect the outstanding matter related to import energy and combustion turbine usage identified for resolution in the methodology (noted in the August 7 Evidence of Liberty). The result of this forecast is that the estimated cost for fuel and purchased power in 2009 is now $641.7 million. This is $82.2 million higher than the forecast contained in NSPI's initial Application...
>
> [Exhibit N-67, p.1]

[27] The Agreement deals with the 2009 fuel cost as follows:

> 4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.
>
> 5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.
>
> 6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.
>
> [Exhibit N-69, p. 2]

[28] The Agreement proposes that the base fuel cost for 2009 rate making purposes be set at $545 million, an increase of $75 million over the 2007 compliance fuel cost. As per NSPI's update[3], the actual cost of fuel for 2009 may be $82 million more than the $559.5 million proposed in the application. The difference between the base fuel cost for 2009 of $545 million and actual fuel cost for 2009 is proposed to be recovered through the proposed Fuel Adjustment Mechanism starting on January 1, 2010, as discussed later

[3] Exhibit N-67

in this decision. If fuel costs were to drop below estimates, that would be credited to customers under the Fuel Adjustment Mechanism.

[29] NSPI uses coal to produce 71% of its energy requirement[4]. In addition, NSPI purchases its fuel using a portfolio strategy previously approved by the Board. The Board in its decision dated March 31, 2005[5] directed NSPI to use a short, medium and long term fuel procurement strategy to protect customers from short term price fluctuation.

[30] Recently the price of oil has come down in world markets. However, NSPI utilizes very little heavy fuel oil to produce electricity. The world price of coal, which is NSPI's dominant fuel to produce electricity, has not fallen nearly as dramatically. The effect of any decrease in coal prices will be delayed due to the use of the fuel procurement strategy, which includes long term commitments already in place prior to the decrease in world fuel prices.

4.1.1 Findings

[31] The Board has considered the evidence filed relating to the fuel cost. The evidence before the Board is that the actual cost of fuel most likely will exceed the proposed base cost for 2009 of $545 million. NSPI estimates that the actual cost may be as high as $640 million[6].

[32] The Board approves the proposed fuel cost for 2009 as noted in the Agreement.

---

[4] Exhibit N-1 (a), p. 13

[5] 2005 NSUARB 27

[6] NSPI update dated September 5, 2008

4.2 Future Natural Gas Requirements and Purchased Power

[33] Liberty, in its Statement, raised two issues for the Board's consideration:

> ... We therefore would like to underscore two points of future vigilance suggested by our testimony, as NSPI continues to pursue efforts to minimize fuel costs. One particularly notable feature of both the original and updated forecasts is that NSPI now expects that the dual-fuel steam units at Tuft's Cove will run essentially entirely on gas in 2009. That places NSPI in a different situation from what has been experienced in the past, when large amounts of natural gas were available for resale in a manner that produced large cost offsets to the benefit of customers.
>
> NSPI thus will not have the same opportunities in 2009 to resell natural gas that it has had in the past, unless oil prices move the great distance required to come more into line with their historical relationship to natural gas. In any event, NSPI's opportunities to reduce costs through the sale of natural gas are fast approaching an end. NSPI's primary gas-supply contract has only two years remaining. We therefore want to re-emphasize the point made in our evidence that NSPI continues not to have a strong track record of dealing with gas suppliers other than its affiliate. The physical and contractual aspects of the gas-supply relationships that NSPI will have to cope with in the not-too-distant future are complex, will take substantial time to conclude, and are generally undertaken by utilities having broader relationships with participants in the marketplace. Consequently, we underscore the need for the Company to be identifying its alternatives and developing a strategy for pursuing them aggressively now. We believe it is very important for NSPI to keep the Board and its stakeholders apprised of its progress in this important area as the next months unfold.
>
> Another matter our evidence addressed is the value that imports of electric power produce for NSPI's customers. Such imports have grown rapidly over the last several years. NSPI acknowledges the attraction of low-cost power imports, but points to practical limits that constrain its ability to make more comparatively economical imports. One example is the transmission capacity connecting Nova Scotia to New Brunswick. Liberty believes that it will be important in the near term for NSPI to analyze and pursue all measures that may serve at reasonable cost to eliminate barriers to making economical, off-system electricity purchases, and to demonstrate to the Board that it is doing so.
>
> [Liberty Statement, Exhibit N-74, p. 2]

[34] In response to Board Counsel's question, Mr. Antonuk stated:

> ... We do, however, want to state that whether or not the settlement is accepted we continue to believe that a couple of very important issues remain for NSPI to focus on as markets continue, as we expect them, to be volatile into the future. We think it's important to keep in mind matters such as replacing natural gas supply when the current agreement with Shell runs out in the very short term, and ensuring that NSPI's system can accommodate full participation in off-system electricity purchases will be important in securing economical and continuous supply in future uncertain energy markets. So, we look forward to hearing more in the coming months about the company's plans in those two important areas.
>
> [Transcript, September 18, 2008, pp. 129-130]

[35] Rob Bennett, President and CEO of NSPI, shared Liberty's comments in his Opening Statement:

> ... There's certainly more to do in terms of exploring the development of new transmission infrastructure. This will enable the aspirations we have for renewable energy, which we know are shared by Nova Scotians.
>
> [NSPI Opening Statement, Exhibit N-73, p. 2]

[36] The Honourable Stephen McNeil, MLA, Leader of the Nova Scotia Liberal Party, also noted the importance of interprovincial transmission capacity.

4.2.1 Findings

[37] The Board accepts Liberty's comments with respect to the sale of natural gas contracts. NSPI purchases its natural gas under contract from its suppliers and sells the surplus quantity to third parties, after its use of a portion of the supply to generate power. In a majority of cases, NSPI has used Emera Energy, an affiliate company, to purchase its surplus natural gas and to sell it. The Board understands Liberty's concern that NSPI has not built enough market contact and transparency to ensure that its future gas procurement will be competitively priced.

[38] The Board directs NSPI to review Liberty's comments with respect to future natural gas purchases and file a report with the Board, no later than April 30, 2009, on how it plans to address this concern.

[39] The Board also accepts Liberty's comments on the second issue relating to NSPI's transmission capacity to import and export power. NSPI is directed to consider this issue and file a report with the Board no later than June 30, 2009, outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board is mindful

that NSPI has, in the 2008 ACE Plan, included a request for capital expenditures related to this issue.

5.0 OM&G

5.1 Overview

[40] In its original application, NSPI requested a $20.6 million increase in Operating, Maintenance and General Expenses ("OM&G") for the 2009 test year.

[41] As a result of the Agreement, the proposed increase for OM&G costs was reduced to $15.8 million. The $4.8 million reduction is comprised of the following components: a $3.4 million decrease from the amount originally proposed for vegetation management, a reduction of $1.0 million to the projected net bad debt expense and a $400,000 reduction for insurance costs.

[42] As noted above, most of the formal intervenors joined as signatories to the Agreement, which specifically addressed the proposed $3.4 million reduction for vegetation management from the amount originally requested in the rate application. However, at the hearing, this proposed reduction was opposed by the NDP Caucus.

[43] Mr. Steele also expressed concerns during the hearing with respect to executive compensation, an issue also identified in many letters received by the Board from members of the public.

[44] Moreover, over the past two years leading to the present rate application, NSPI has undergone an operations review ordered by the Board with respect to its organizational structure and its level of OM&G expenditures.

[45] The issues of vegetation management, the operations review, and executive compensation are canvassed more fully below.

5.2 Vegetation Management

5.2.1 Submissions - NSPI

[46] In his Opening Statement, delivered at the commencement of the hearing, Mr. Bennett submitted that the proposed expenditure increase for vegetation management should be approved by the Board:

> I want to underline the importance about increasing spending on tree trimming and vegetation management. We are taking important steps in this program.
>
> Stable and reliable transmission and distribution systems are rightfully an expectation of this Board. It's also the expectation of regulatory bodies that oversee the bulk power system. For example, the North American Electric Reliability Corporation - or NERC - has recently enhanced transmission line tree trimming requirements.
>
> [NSPI Opening Statement, Exhibit N-73]

[47] NSPI reasserted its position in its Closing Submission, citing Mr. Bennett's testimony at the hearing about vegetation management and its impact upon reliability:

> When Mr. Steele asked about vegetation management spending and its relationship to reliability, Mr. Bennett explained:
>
>> In fact, the decision to change the degree of funding in the vegetation management program was arrived at with a balanced consideration for all of the needs of our customers and reliability going forward. That includes the need to sustain our workforce through succession planning and other operational activities in the business that require funding.
>>
>> I believe that we've achieved that balance of a significant level of additional funding in the vegetation program. $3.6 million more than is being spent today will definitely increase the reliability of the system. It will allow us to execute programs that will effectively storm-harden the system, and at the same time the settlement agreement allows us to, in a balanced way, take on those other challenges that have long-term beneficial impacts, such as sustaining, developing and training our workforce to deal with our customers' needs in the future.
>>
>> So, I'm very comfortable that the level of investment that we will be making will make a difference. I should also note that the choice of $3.6 million was

> arrived at because it had been reviewed in the past by various consultants with the Board and there was an understanding of that level of additional investment as being important and effective.

> Importantly, all parties to the Settlement Agreement consider that the increase in vegetation management expenditure of $3.6 million is a reasonable and appropriate enhancement. All parties are also aware that, in future, it may be necessary to consider the additional investment that was proposed by NSPI in this proceeding but will not be implemented.

> [NSPI Closing Submission, September 25, 2008, pp. 3-4]

5.2.2 Submissions - NDP Caucus

[48] The NDP Caucus was the only formal intervenor who raised this issue at the hearing. In his closing argument, Mr. Steele stated:

> With respect to system reliability or what I might refer to as outages, Nova Scotia Power has this year proposed an extensive program of vegetation management in order to improve system reliability. The company's evidence appears to acknowledge that it is possible for the company to raise its game on vegetation management to another level so that the level of outages caused by vegetation contact can get down to the levels already achieved by New Brunswick Power. But we note the settlement agreement contains a cut of 3.4 million dollars from this vegetation management program. A program designed to address specifically and directly a major concern to the public has been cut as part of the settlement agreement.

> For that reason, it is difficult to see how the company can possibly achieve its goals with respect to outages caused by vegetation. We believe it is regrettable that of all the items that could have been picked to find the necessary savings that that item has been picked.

> [Transcript, September 18, 2008, pp. 149-150]

[49] He concluded:

> ... It may be that the global amount of cost savings have been agreed upon by the signatories to the settlement agreement but it seems to us fair and we recommend to the Board that the expense for vegetation management be restored and that the difference be made up by taking at least some of that amount from executive compensation. That may be a symbolic move by the company but I believe it would be a very important one.

> [Transcript, September 18, 2008, p. 151]

5.2.3 Findings

[50] With respect to vegetation management, NSPI is requesting a net increase in proposed expenditures.

[51] In its original rate application, NSPI requested an increase of $7.0 million over the prior year, which would have amounted to a total of $13.8 million for 2009. Thus, despite the $3.4 million reduction resulting from the Agreement, an overall net increase in vegetation management activity will be achieved. Vegetation management expenses will increase to $10.4 million for the 2009 test year, a net increase of $3.6 million over the last compliance filing.

[52] The Board notes the testimony of Mr. Bennett, who stated that increased activity in vegetation management will enhance service reliability for NSPI's customers.

[53] Further, the Board is also mindful that the Agreement specifically addressed the issue of vegetation management. The formal intervenors who signed the Agreement represent all rate classes of NSPI's customers.

[54] Taking into account all of the evidence, the Board is satisfied that the proposed total expenditure of $10.4 million for vegetation management (an increase of $3.6 million), as contemplated under the terms of the Agreement, is reasonable and appropriate in the circumstances.

5.3 Operations Review

5.3.1 Introduction

[55] In its decision dated March 10, 2006, the Board ordered a review of NSPI's operations:

> The Board directs that an operations review be carried out on NSPI's operations. The review shall encompass a detailed examination of NSPI's organizational structure, its level of OM&G expenditures, and any other pertinent areas which may come to light, with a view to determining whether cost savings and operational efficiencies can be achieved. NSPI is directed to prepare the terms of reference for the operations review and submit them to the Board for approval by May 31, 2006. The terms of reference shall also set out the procedures for identifying and selecting the firm or person who will perform the operations review.
>
> [Board Order, P-882, April 12, 2006, Schedule "C"]

[56] In response to this direction, NSPI filed a report prepared by Accenture Inc. on January 8, 2007 (the "Accenture Report").

[57] The Board ordered that the Accenture Report be filed in advance of the 2007 rate hearing. In that Rate Decision, the Board directed that interested stakeholders provide input on the review process:

> [54] The Board has determined that the process concerning the operations review will continue following this decision and that interested stakeholders will have an opportunity to participate - the CA already has. The Board is interested in soliciting views of parties to the rate case proceeding with respect to the appropriate course of action. Accordingly, the Board will provide an opportunity for input concerning the desirability of a further review of NSPI's operations as suggested by the CA or whether parties are satisfied that Accenture has met the Board's terms of reference.
>
> [Board Decision, February 5, 2007, P-886, pp. 24-25]

[58] Following its review, the Board determined that the scope of the Accenture Report was much narrower than the terms of reference developed for the operations review. It concluded that the Report's focus was limited to the Corporate Services component of NSPI's overall OM&G functions (i.e., which comprised less than 20% of the total OM&G costs).

[59] Accordingly, in a letter dated May 18, 2007, the Board directed that it would engage an independent expert to carry out a review of the sectors of NSPI's OM&G costs not covered in the Accenture Report, including executive compensation. It retained Kaiser Associates to conduct the operations review and the findings were contained in a report dated June 19, 2008 (the "Kaiser Report"). Kaiser Associates released a separate report with respect to executive compensation on June 16, 2008 ("Kaiser's Executive Compensation Review"), which is canvassed in greater detail in the next section of this decision.

[60] The Kaiser Report concluded:

> Following its research and analysis presented in the detailed findings, Kaiser believes that NSPI is a well managed utility that operates at a lower OM&G cost basis than its comparators when adjusted for its scale. NSPI has shown a rise in costs from 2004-2006, driven by investments in Emergency Services Restoration, vegetation management and a onetime adjustment made for pension expense. These expenses were reviewed and approved by the UARB. In addition NSPI was affected by external factors, for example: particularly adverse weather in the province; and, a major customer was not in service in 2006, depressing revenue. Preliminary data for 2007 shows OM&G expenditures are projected to remain flat.
> . . .
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. i]

[61] However, the Kaiser Report identified NSPI's Work Management System as an area of concern:

> Work Management System (WMS) - Rather than use an integrated WMS, NSPI relies on a number of different WMSs aligned by function (customer operations, maintenance, etc.) leading to lack of coordination and sub-optimal utilization. NSPI management is aware of this problem and is taking steps to address the WMS; NSPI management has a $6-7M application for a transmission and distribution WMS upgrade in its 2008 capital budget. WMS is a key area of study in benchmarking and a critical recommendation. Although the integrated nature of WMS means it affects multiple areas of company operations, Kaiser has presented its findings and recommendations related to WMS in the Customer Operations section (pages 75-86). As Kaiser has cautioned the UARB, there are significant efficiencies to be gained, however, implementing an enterprise-wide, integrated WMS is a substantial investment which carries significant risk and will require the commitment of personnel resources.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. ii]

[62] The organizational design of NSPI's existing power production plants was also identified as an area of improvement:

> Organizational Design - NSPI does not utilize a standard organizational design across its existing plants. Due to attrition in its Point Tupper plant, NSPI is testing an alternate organizational structure, which after evaluation may be expanded for use in other facilities. This structure is much less hierarchical in nature, therefore relies less on highly experienced supervisory staff. NSPI uses a distributed model in organizing its plants, allowing for operational flexibility but also possibly creating redundancies in engineering and support functions.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. ii]

[63] The Kaiser Report recommended:

> **[Organizational] Design**
>
> Research indicates that NSPI has a greater number of direct reports as well as less accountability in plants, particularly in the maintenance and planning areas. NSPI should develop a plan for the board identifying its [organizational] design and workforce plan over the coming years as part of its succession planning initiative. The plan should address some of the standardization of organization and centralization issues raised in the detailed findings.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. iv]

5.3.2 Submissions - NSPI

[64] In its application, NSPI listed a number of reviews undertaken with respect to OM&G costs. It stated that the findings of these reviews have been generally supportive of NSPI's management of OM&G expenses[7]. Further, NSPI stated that, in constant dollars, it has reduced OM&G expenditures since 2000, through effective cost control mechanisms.

[65] In its Reply Evidence, NSPI questioned a number of the findings in the Kaiser Report, including recommendations with respect to website and Interactive Voice Response System automation, meter reading and customer service staffing levels. The

[7] Exhibit N-1, p. 98

Board observes that most of these issues identified in the Kaiser Report were addressed and clarified during the Information Request process of this hearing.

5.3.3 Submissions - Intervenors

[66] The formal intervenors made no submissions at the hearing with respect to the OM&G operations review.

5.3.4 Findings

[67] As noted above, as a result of prior Rate Decisions, the Board ordered a comprehensive operations review of NSPI's organizational structure and its level of OM&G expenditures.

[68] The Kaiser Report concluded "that NSPI is a well managed utility that operates at a lower OM&G cost basis than its comparators when adjusted for its scale"[8]. Further, it observed "that NSPI compares favorably to the benchmark firms on OM&G expense when normalized by power generated, number of customers, number of employees and amount of revenue generated"[9].

[69] Stakeholders provided their input with respect to the terms of reference of the operations review prior to the work undertaken by Kaiser Associates. The Kaiser Report was reviewed by the formal intervenors who participated in this hearing. While some of the intervenors submitted evidence suggesting reductions to certain aspects of NSPI's OM&G costs, the Board found no evidence that these intervenors challenged the Kaiser Report's

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[8] Exhibit N-5, p. i

[9] Exhibit N-5, p. iii

conclusion that NSPI is "a well managed utility", which "compares favorably to the benchmark firms on OM&G expense when normalized [over a number of factors]".

[70] While NSPI, in its Reply Evidence, appeared to distance itself from some of the findings in the Kaiser Report, the Board interprets this Report as being favourable, in most respects, to NSPI's management of OM&G expenses.

[71] Taking all of the evidence into account, the Board accepts the findings of the Kaiser Report, as well as that of the Accenture Report, that NSPI's organizational structure is appropriate and its management of OM&G expenditures is reasonable.

[72] However, the Kaiser Report identifies NSPI's Work Management System as a recommended area of improvement, stating that an integrated system would improve coordination and efficiency. NSPI has committed to the implementation of a Work Management System with respect to its transmission and distribution operations. This new system will, according to NSPI, benefit NSPI's customers by the more efficient and timely handling of the "work order" process. Accordingly, the Board directs that NSPI advise the Board on the balance of the Kaiser Report's recommendation about extending an integrated Work Management System to the remainder of NSPI's operations. This report shall be filed no later than December 31, 2008.

[73] The Kaiser Report also recommends that NSPI develop a plan for the Board identifying NSPI's organizational design and workforce plan for its power production plants, as part of its succession planning initiative. NSPI is currently testing an alternate organizational structure at one of its plants. The Board directs that NSPI file a report on its progress no later than March 31, 2009. The Board also reserves the right to issue further directions on this issue.

5.4 Executive Compensation

5.4.1 Introduction

[74] The issue of executive compensation has been a matter which has arisen in this and prior rate applications.

[75] As a result of a much broader OM&G operations review (discussed in greater detail in the section above), the Board retained Kaiser Associates to conduct an Executive Compensation Review. As part of this review, Kaiser Associates examined a report prepared for NSPI by Towers Perrin, which is part of an annual reporting required by the Board.

[76] With respect to salary, NSPI sets its target salary at the 50th percentile mark within a group of comparable operators consisting of Canadian utilities. Towers Perrin concluded that NSPI executives (a management team comprised of 11 members) are paid compensation which is 11% lower than the median pay of the comparator utilities chosen for its review.

[77] However, applying changes which it recommends to Towers Perrin's methodology, Kaiser Associates concluded that NSPI's management team is actually paid a salary which is 0.5% higher than the median pay of the comparators it identified for its study. Further, Kaiser Associates found that the two highest paid NSPI executives earn about 41% more than executives at comparable utilities, while the two lowest paid executives make 24% and 37% less, respectively, than the benchmarks.

[78] Kaiser Associates recommends that future benchmarking studies of NSPI's executive compensation incorporate the following elements:

- Including the whole bonus figures in TTC [Total Target Cash] benchmarking;
- Include stock-based compensation as part of the analysis;
- Look at compensation position by position as well as in the aggregate;
- Factor in cost of living adjustments;
- Benchmark targets and achievement on executive scorecard against comparators.

[Kaiser Executive Compensation Review, Exhibit N-3, p.1]

[79] The review by Kaiser Associates revealed that the Towers Perrin report utilizes 50% of the target cash bonus for NSPI in its TTC benchmarking, compared to 100% for the comparator utilities. Further, Kaiser Associates concluded that the Towers Perrin analysis may be distorted based on differences in the regional cost of living factors which it applied.

[80] However, Kaiser Associates also found that NSPI executives tend to be better qualified in terms of tenure and professional degrees as compared to comparator utilities.

5.4.2. Submissions - NSPI

[81] In its Reply Evidence, NSPI stated that Kaiser's Executive Compensation Review, conducted on behalf of the Board, supports NSPI's view that it is paying reasonable compensation to its executive team. However, NSPI opposes the recommendations made by Kaiser Associates with respect to the methodology for reviewing executive compensation.

[82] NSPI further asserts that the issue of executive compensation was canvassed in this rate application. In its Closing Submission, it submitted:

> The parties to the Settlement Agreement have had access to the Kaiser Report on Executive Compensation from early in the proceeding - a Report that concludes that NSPI's executive compensation is on target at the mid-point of the range for comparable companies. IRs were posed on this topic by some parties and answered by NSPI. As Mr. Bennett explained, all

areas of cost have been carefully examined and a balance has been achieved following careful consideration and input of stakeholders.

[NSPI Closing Submission, September 25, 2008, p. 3]

5.4.3 Submissions - NDP Caucus

[83] During closing argument, Mr. Steele submitted:

> With respect to executive compensation, the settlement agreement ensures that this topic will go unexamined for at least another year. Even though it is the one topic that probably catches the public's attention the most. Although not everyone will claim to be an expert on rate setting for Nova Scotia Power, it is fair to say that just about everyone considers themselves to be an expert on incomes, whether that be a politician's income or a power executive's income. And while Nova Scotia Power compensation levels may be comparable to the mid range of other public utilities across Canada, the fact is that the levels of compensation are simply enormously out of keeping with other incomes in the Province of Nova Scotia. There must be a problem with the comparators.
>
> It is difficult for most Nova Scotians whose incomes are fixed or rising much more slowly than the cost of living to pay higher rates to a Nova Scotia company whose executives earn high six figure incomes, sometimes approaching a million dollars a year in salary, stock options and bonuses. We are mindful of the fact that Nova Scotia Power is free to pay their executives whatever they chose and we accept that the issue for this hearing is what portion of that executive compensation is included in the rate base to recover from rate payers. It may be that the global amount of cost savings have been agreed upon by the signatories to the settlement agreement but it seems to us fair and we recommend to the Board that the expense for vegetation management be restored and that the difference be made up by taking at least some of that amount from executive compensation. That may be a symbolic move by the company but I believe it would be a very important one.

[Transcript, September 18, 2008, pp. 150-151]

5.4.4 Findings

[84] Taking into account all of the evidence, the Board finds that the compensation presently paid to NSPI's management team, as viewed on a collective basis, is not materially higher than that paid to comparable Canadian utilities, even adopting the methodology recommended by Kaiser Associates.

[85] The Board's obligation is to ensure that the OM&G expenses, including the collective compensation paid to managers as a group, is reasonable. Setting of individual

salaries within the envelope approved by the Board is a matter for NSPI's Board of Directors and Management. The Board observes that few, if any, issues have attracted public comment, often amounting to outrage, as did the salary paid to NSPI's highest paid executives. The Board trusts that NSPI's Board and Management have heard the message.

[86] The Board directs that NSPI continue to file an annual report with the Board respecting executive compensation. In the interim, and in light of this decision, NSPI should further consider the recommendations contained in Kaiser's Executive Compensation Review. The Board will continue to monitor this issue and it reserves the jurisdiction to issue further directions with respect to the reporting of executive compensation.

5.5 Conclusion - OM&G

[87] As noted above, taking into account all of the evidence (including but not limited to the evidentiary filings in this application, the Agreement, and the submissions of the parties), the Board approves a $15.8 million increase in OM&G expenses for the 2009 test year. This increase will result in a total OM&G expenditure of $216.6 million for the test year. The Board directs NSPI to incorporate the specific reductions to OM&G set out in the Agreement (i.e., those outlined for vegetation management, net bad debt expense and insurance costs).

[88] Further, based upon its consideration of the operations review, the Board concludes that NSPI's organizational structure is appropriate and that its management of OM&G expenses is reasonable. Subject to Work Order approval, NSPI will proceed with

the implementation of its Work Management System associated with its transmission and distribution operations. NSPI must report on the implementation of an integrated Work Management System to the remainder of its operations, no later than December 31, 2008. NSPI is also directed to continue the review of its organizational design for its existing power production plants and to provide a status report to the Board no later than March 31, 2009.

[89] With respect to executive compensation, the Board is satisfied that the overall level of compensation currently paid to NSPI's executive team is reasonable, when compared to other Canadian utilities used as comparators. NSPI must continue to file an annual report with the Board with respect to executive compensation. Further, the Board reserves the jurisdiction to issue further directions with respect to the reporting of executive compensation.

6.0 FINANCIAL ISSUES

6.1 Calculation of Return on Equity

[90] It became apparent during the examination of NSPI's Policy Panel that there was a difference of opinion between the Company and intervenors concerning the proper method of calculating return on equity in any given year. Briefly stated, the Company's position is that the calculation should be made on the basis of the company's actual equity, up to the 40% maximum approved by the Board (the maximum equity will increase to 45% under the Agreement). The intervenors' position, on the other hand, is that return on equity

should be calculated based on the common equity ratio of 37.5% approved by the Board "for rate making purposes".

[91] The Board adjourned the hearing to enable Board Counsel to consult with NSPI and the intervenors about this issue. When the hearing resumed, Board Counsel indicated that the parties were unable to reach agreement on the issue and that it should be resolved in a separate process. Board Counsel also noted that the issue would probably not crystallize until a determination has to be made whether the Company's regulated earnings in 2008 would represent a return on equity in excess of 9.8%.

[92] Neither the Company nor any of the intervenors requested that the Board deal with this issue in the context of the settlement and the issue was not mentioned in any of the post-hearing submissions. Obviously, the parties are prepared to have the Board approve the settlement without first resolving the return on equity calculation issue.

[93] Having regard to the foregoing, the Board will deal with the calculation issue in a subsequent proceeding which can be initiated at the request of the Company, any intervenor in the present proceeding or on the Board's own motion.

7.0 ABOVE THE LINE RATES

7.1 Revenue to cost ratios

[94] As noted, the Agreement proposes that the 9.3% increase in revenue be applied equally across all rate classes. As a result, the revenue to cost ratio for the General Demand class increases to 107.2% and the ELI 2P-RTP class reduces to 91%.

[95] The Board has, for many years, set a target revenue to cost ratio of 95% to 105% for all customer classes. The Agreement causes a weakening in the revenue to cost ratios from that approved in the last rate case.

[96] Dr. Stutz, in his Statement recommending approval of the Agreement, comments on this issue:

> ... The Agreement deals with two key areas raised in my prefiled evidence:
>
> - The increase in total revenues for 2009 has been reduced.
> - The spread in the increases in class revenue responsibility has been narrowed.
>
> [Stutz Statement, Exhibit N-75]

[97] He goes on to state:

> - As I explained in my evidence, rate stability justifies moving the increase for the ELI 2P-RTP rate toward the average, even at the "cost" of an R/C ratio below 95%.
>
> [Stutz Statement, Exhibit N-75]

[98] Dr. Stutz was questioned by Mr. Steele about the revenue to cost ratios:

> Q. Now, given that the rationale for the 95 percent ratio has not been borne out by experience, what justification can you offer for the revenue to cost ratio in that class actually going under 95 percent now if the settlement agreement is approved sitting at 91 percent?
>
> A. The rationale is provided in the last paragraph of my statement.
> There are a variety of considerations, one of which -- and the Board has taken this into account in many occasions before is rate stability.
> In my original evidence, I in fact proposed a revenue to cost ratio below 95 percent, because I felt it was important to preserve revenue stability.
>
> . . .
>
> Q. Would you agree with the proposition that the members of the commercial general class are paying more than their fair share?
>
> A. No, I have difficulty with that proposition. Because it suggests that the revenue to cost ratio is the sole indicator of what's fair. And I think fairness is a very broad concept.
> I think, for example, it's not fair if you're charging everyone 9 percent to give someone 18. So, I wouldn't agree with it.

> I would agree that [that] one indicator which the Board has relied on, to some extent, shows them outside the range the Board would like to se [see].
>
> [Transcript, September 18, 2007, pp. 137-138]

[99] Leanne Hachey, on behalf of the Canadian Federation of Independent Business, raised the concern that cross-subsidization is taking place if the revenue to cost ratio of one class is 91% and another class is 107%. She went on to say:

> . . . And why CFIB believes these inequities should be address[ed] is one, they do clearly contravene Bonbright's principles of public utility rates that the fairness of the specific rates and the apportionment of total cost of service among the different consumers the avoidance of undue discrimination and the efficiency of rate classes to discourage wasteful use of service.
>
> In other words, in layman's' terms everybody should pay their fare share. People shouldn't be paying the costs of others.
>
> [Transcript, September 17, 2008, p. 52]

[100] The CA also dealt with the issue in his written submission:

> The CA is concerned by the impact of the “across the board” increase on the revenue/cost ratios. That is a variance that is beyond the target zone of 95% to 105% set by the Board and represents a cross-subsidization that, the greater the variance, the greater difficulty in justification.
>
> However, the “across the board” allocation of the agreed-upon increase was a trade-off of a number of factors (see for example, the statement of Dr. Stutz dated September 18, 2008 exhibit N-75).
>
> Ultimately, each of the proponents of the Settlement Agreement was prepared to accept the impact on the revenue/cost ratios for the purposes of achieving the settlement.
>
> [CA Submission, September 25, 2008, p. 4]

7.2 Findings

[101] The Board is concerned about the weakening in revenue to cost ratios. However, the Board accepts the evidence of Dr. Stutz that revenue to cost ratios are not the sole indication of what is fair. Dr. Stutz noted in his evidence that one of the rate

classes had a disproportionate increase relative to the average increase. By virtue of the Agreement, he noted that the spread in increases in revenue class responsibility had been narrowed. He also spoke to the importance of rate stability which is, of course, one of Bonbright's criteria of a sound rate structure.

[102] As noted earlier in the decision, the Agreement enjoys the support of representatives of all of the customer classes. In the interest of achieving rate stability in this proceeding, the Board will permit the deterioration in revenue to class ratios caused by the Agreement.

[103] The Board anticipates, however, that at the next opportunity an adjustment to bring the two rate classifications back within the target range will be a priority.

8.0 DEMAND SIDE MANAGEMENT

8.1 Submissions

[104] NSPI in its application stated that:

> The parties agreed that NSPI would be the temporary DSM administrator and that early DSM program implementation by the Company would transition to the new administrator. The parties also agreed to changes to the timing and mix of DSM programs resulting in DSM spending of up to $3.1 million for 2008 and $9.8 million for 2009. The total expenditure over the 2008-2009 period was identified to be $12.9 million, the same level of investment as proposed for that period in the January 31, 2008 filing. Similarly, cumulative energy and demand savings targets would remain at 66 GWh and 8.8 MW respectively, the same as identified in the January 31, 2008 filing for the 2008-2009 period.
>
> The Settlement Agreement deferred UARB consideration of several issues that were not necessary to resolve during the April 2008 hearing. These issues included NSPI's proposal for a DSM Cost Recovery Mechanism, including a Lost Revenue Adjustment Mechanism (LRAM), performance indicators, incentives and penalties, and the proposed role and structure of the DSM Steering Committee and DSM Advisory Council. The Parties agreed that NSPI could defer DSM program expenditures in 2008 and 2009 for future recovery over a reasonable period determined by the Board, and that the appropriate allocation of costs among customer classes would be considered at the time of NSPI's request for recovery of the DSM expenditures.

[Exhibit N-1(a), p. 85]

[105] NSPI's application proposed to recover the 2008 and 2009 Demand Side Management (DSM) costs as follows:

> With the DSM investment as outlined in the DSM Settlement Agreement of $3.1 million for 2008 and $9.8 million for 2009, the total forecast expenditure over the 2008-2009 period is $12.9 million. NSPI is requesting recovery of this $12.9 million in equal increments over 2009, 2010 and 2011. NSPI proposes that $4.3 million be incorporated into the 2009 test year revenue requirement to reflect DSM costs. The recovery is further discussed in Section 5 of this Application.
>
> [Exhibit N-1(a), p. 86]

[106] The Agreement proposes that the amortization period for the 2008 and 2009 DSM costs be increased from three years to six years[10]. The net effect of this change is the reduction of the revenue requirement by $2.1 million in 2009[11].

8.2 Findings

[107] The Board has considered the amortization of the 2008 and 2009 DSM program costs over six years as proposed in the Agreement. Based on the size of rate increases proposed in the application, the Board agrees that it is reasonable to amortize these expenditures over a longer period than the three years proposed in the Application. The Board approves the amortization of DSM expenditures for 2008 and 2009 in the amount of $12.9 million over six years starting in 2009.

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[10] Exhibit –69, para. 11

[11] Exhibit N-72

9.0 NSPI EARNINGS

[108] Included in the List of Issues was "NSPI's 2008 earnings (including Q1)".

[109] The NSPI panel was asked about NSPI's 2008 earnings to date:

A. (Blunden) Yes, so at an average rate base and of course with the equity thickness range and the ROE, it generally ranges from, for regulated purposes, somewheres around 100 [million dollars] to maybe 107, 108, or something like that, I think.

Q. And Q1 earnings were 57.9?

A. (Blunden) I believe that's correct, yes.

Q. And Q2 earnings were 30 some odd?

A. (Blunden) That's about right, yes.

Q. And about that and despite the range, you still think you're going to hit the rate of return?

A. (Blunden) Yes. As indicated by Mr. Bennett, we're expecting our fuel costs over the balance of the year to be 40 to $50,000,000 higher than they were in the same period of last year. So although optimistic, between the higher fuel prices and of course with the settlement agreement in place, the catch earnings we're expecting to be in the range from this, from where we sit today.

[Transcript, September 18, 2008, p.104]

[110] For purposes of the 2008 fiscal year, as a result of the settlement agreement in the 2007 rate proceeding, voluntarily entered into by NSPI, earnings in excess of 9.8% will be applied to reduce two deferral accounts previously approved by the Board, and will not go to NSPI's shareholders. The first is a gas deferral in the amount of $8 million and the other a deferral of tax payable by NSPI with a balance of approximately $120 million.

[111] In the final submission on behalf of the NDP Caucus, the Board was asked to include in the final Order specific direction as to how excess profits, if any, in 2009 will be applied. Mr. Steele, on behalf of the NDP Caucus, went on to say:

> ...This will go a long way to reassure the public that at the same time they are paying significantly more that the company is not earning excess profits.
>
> [Transcript, September 18, 2008, p. 143]

[112] Under the *Act*, the Board is required to provide NSPI with the opportunity to earn a "reasonable rate of return on rate base". One of the key components of return on rate base is return on common equity. Pursuant to the Agreement, the allowed return on equity is between 9.1% and 9.6%, with rates being set at 9.35%.

[113] The Board's remedy, if NSPI is likely to over earn, is to step in and lower rates. The Board does not direct the application of excess earnings nor does it allow NSPI to retroactively collect from customers if it fails to earn its allowed rate of return. The implementation of a FAM will reduce the possibility of over earning as fuel is the largest of NSPI's costs that may vary significantly from forecast. Under the Fuel Adjustment Mechanism, any over earning related to fuel will be adjusted the following year.

[114] Nevertheless, the Board recognizes the fact that NSPI had unusually high earnings in Q1 and Q2 of 2008 at the same time it was seeking a 12.1% increase in rates, causing great consternation with the public, already very skeptical of NSPI's need for increased revenues.

[115] The Board will closely monitor NSPI's earnings in 2009, mindful of its power to step in and remedy an over earning situation by a reduction in rates.

10.0 FUEL ADJUSTMENT MECHANISM

10.1 Introduction

[116] In its rate application, NSPI requested implementation of a Fuel Adjustment Mechanism (FAM), effective January 1, 2009.

[117] In a decision dated December 10, 2007[12], the Board determined that the approval of a FAM is in the public interest, provided NSPI satisfies certain conditions prior to the implementation of the FAM. The preconditions imposed on NSPI by the Board included the filing of templates for monthly and annual information reports, the filing of a standard methodology for fuel forecasts and the filing of the FAM tariff documents. The Board directed NSPI to engage in a stakeholder process leading to its implementation, with a potential start date of January 1, 2009.

10.2 Submissions - NSPI

[118] NSPI submits that it has concluded its preparatory work in collaboration with its stakeholders and that it has reached the point where it is appropriate to implement the FAM, effective January 1, 2009. It submits that reporting, forecasting methodology and auditing requirements have been developed to allow the FAM to function properly.

[119] In its application, NSPI stated that it is appropriate to implement the FAM in the context of this general rate application:

> Under the FAM Framework, NSPI may reset base fuel costs through a General Rate Application (GRA) or every two years under a FAM. NSPI has forecast fuel costs for 2009 and has included increased fuel costs in this Application for 2009 rates. Through this General Rate Application, the Board would establish the initial Base Cost of Fuel for the FAM, and

[12] 2007 NSUARB 174

incorporate the agreed reduction in Return on Equity effective with the implementation of the FAM.

[NSPI Application, Exhibit N-1, p. 75]

[120] In its Reply Evidence, NSPI quoted comments contained in a letter dated June 23, 2008, from counsel for the Nova Scotia Department of Energy ("NSDOE") as indicative of the satisfaction of stakeholders with the consultative process undertaken for the development of the FAM:

> NSDOE has been a party to these discussions and, to date, is generally satisfied with the level of discourse and cooperation between NSPI, consultants, and stakeholders in the development of the FAM Plan of Administration, and the degree to which the principles of transparency and disclosure have been adhered to in relation to the administration of the fuel procurement policy and the proposed Plan of Administration for the FAM. The stakeholder process has facilitated settlement between NSPI, Board consultants, and stakeholders on key points in the POA [Plan of Administration].
>
> [NSPI Reply Evidence, Exhibit N-66, p. 9]

[121] Further, in his Opening Statement at the hearing[13], Mr. Bennett noted that the parties to the Agreement concur with the implementation of the FAM on January 1, 2009.

10.3 Submissions - Formal Intervenors

[122] The formal intervenors made no submissions at the hearing with respect to the implementation of the FAM. The Board observes that all signatories to the Agreement have agreed that the FAM should commence as of January 1, 2009.

[13] Exhibit N-73

10.4 Submissions - Board Consultants

[123] Both Dr. Stutz and Mr. Antonuk indicated in their testimony at the hearing that they are satisfied the FAM is ready to be implemented.

[124] Dr. Stutz concluded in his Statement:

> Sections 1 to 8 of the Agreement deal with the Fuel Adjustment Mechanism (FAM). I agree that the FAM is substantially complete. The arrangements to finalize it provided in the Agreement are reasonable and appropriate. I know of no "unsettled issue" likely to prevent the FAM from coming into operation on January 1, 2009.
>
> [Stutz Statement, Exhibit N-75]

[125] In his testimony, Mr. Antonuk of Liberty indicated that it is appropriate to implement the FAM at this point and that three remaining issues can be resolved prior to its implementation:

> Yes. We believe that that is appropriate and it's difficult to see the settlement operating without the adoption of a FAM based on the way it's structured, and I think its structure clearly contemplates that. For our part, we're optimistic that while there remain issues to be resolved with respect to the FAM that those can and should, and I hope will, be resolved by the parties amicably. In the event they're not, I think they're the kinds of issues that are clearly amenable to prompt and effective resolution by the Board in any event. And those issues are three. One is the use of the API-4 index for performing the forecast of solid fuels. We're in agreement with the NSPI proposal to use that forecast but want that forecast use to be revisited in approximately a year. I believe we actually have agreement on that at the present time but it's not yet committed to writing. The second issue is that we are still working on language that addresses the degree to which there will or won't be consultation by the fuel auditor prior to the commencement of the fuel audits called for by the FAM, and the third is the method to be used for estimating import power sales, and on those latter two discussions -- or issues, discussions have been active among the FAM collaborative participants and I expect those discussions to continue and hopefully to be resolved in the immediate future.
>
> [Transcript, September 18, 2008, pp. 130-131]

10.5 Findings

[126] The implementation of the FAM received full support from the signatories to the Agreement, effective January 1, 2009. In clause 3 of the Agreement, the parties undertake to finalize the FAM documentation and NSPI agrees to file, for Board approval,

a final Tariff and Plan of Administration no later than October 15, 2008. Those documents have been filed and are under review by the Board. The Base Cost of Fuel is proposed to be set at $545 million in 2009 rates.

[127] Further, the Board observes that implementation of the FAM was not opposed by the formal intervenors who did not sign the Agreement.

[128] In their testimony at the hearing, Dr. Stutz and Mr. Antonuk, the Board's consultants, agreed that it was appropriate to implement the FAM at this point. While a few points remain outstanding, they are confident that any such items can be resolved prior to the proposed implementation date.

[129] In this regard, the Board observes that the development of the FAM has followed an extensive collaborative process between NSPI and its stakeholders. The Board's consultants were also involved throughout the entire process. All parties involved in this consultative exercise expressed their general satisfaction with the preliminary Plan of Administration filed with the Board in June 2008.

[130] In its Rate Decision dated February 5, 2007, and in its Decision dated December 10, 2007 giving conditional approval to the FAM, the Board identified at least four prerequisites prior to the implementation of a FAM:

> ...
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [Board Decision, P-887, December 10, 2007, para. 45]

[131] Based upon its review of the evidence and the submissions of the parties, the Board is satisfied that these prerequisites have been fulfilled. The consultative process has also addressed other issues.

[132] The Board is mindful of the concerns of NSPI's customers with respect to the implementation of a FAM. While some may contend that a FAM could result in reduced transparency and less oversight, the reality is quite the opposite. Any future adjustments to the Base Cost of Fuel will occur in an even more transparent manner than is presently the case. Under the FAM, the fuel forecasting process will be subjected to more periodic review by the Board and intervenors.

[133] The Board refers to its previous comments on these points:

> [76] The Board views a FAM as a tool which can actually provide a closer and more timely oversight of NSPI's fuel costs than is presently the case. As noted elsewhere in this decision, under a FAM, assessments as to the reasonableness of fuel expenses and NSPI's performance in obtaining fuel at the lowest price reasonably possible, will be carried out by the Board, as well as Intervenors, on an ongoing and more frequent basis than in the past. In the last ten years, this form of fuel costs examination has occurred four times—always in conjunction with general rate applications. Under a FAM, fuel costs will be determined on an annual basis, following the reporting, analysis and stakeholder involvement in the FAM process throughout the preceding year, which forms the basis for any adjustment.
>
> [77] Customers should also understand that, under a FAM, the rate they pay to NSPI will not go up and down every time the cost of fuel fluctuates. In other words, a FAM will not operate in the same manner as they experience at the gas pumps, where prices can change every week.
>
> [78] Even under the proposed January 1, 2009 implementation date of the FAM, the earliest time a fuel adjustment change to rates could possibly occur would be January 1, 2010. Also, it could only occur then if the previous year's fuel costs passed all the reporting, auditing, and review tests designed to ensure that the cost to be passed on to ratepayers is as low as reasonably possible—a result which, in the Board's opinion, improves its ability to protect the public interest.
>
> [Board Decision, P-887, December 10, 2007, paras. 76-78]

[134] The Board also observes that the implementation of the FAM is accompanied by a 0.2% reduction in the return on equity that can be earned by NSPI (i.e., the target

ROE will decrease from 9.55% to 9.35%). The lower return on equity results in a reduced revenue requirement to be recovered in customers' rates.

[135] Finally, there is a further benefit of a FAM for customers. The implementation of the FAM will allow NSPI to recover its prudently incurred fuel costs. This, in turn, will lower NSPI's business risk profile and foster the improved financial health of the utility over the long term, which could possibly lead to an improved outlook from bond-rating agencies and cause them to upgrade their rating for NSPI. Ultimately, this could benefit ratepayers by reducing NSPI's debt and interest charges, possibly lessening the pressure for rate increases in the future. An improved rating could also positively impact NSPI's ability to procure fuel commodities and to access capital markets for upcoming infrastructure projects.

[136] Taking into account all of the foregoing, the Board approves the FAM, on the basis of the provisions contained in the Agreement. The FAM shall take effect on January 1, 2009, conditional on the final approval of the Tariff and Plan of Administration.

11.0 WRITTEN AND ORAL SUBMISSIONS FROM THE PUBLIC

[137] In the advertised Notice of Public Hearing concerning NSPI’s rate application, the public was advised that they could file submissions with the Board outlining their views regarding NSPI’s application. In response to this notification, the Board received thirty-one written submissions from the public, plus six individuals made presentations at the evening session on September 17, 2008.

[138] Many of the written submissions expressed concerns relating to the adverse impact of another rate increase (the fifth in seven years) on customers, particularly those on fixed or low incomes. Some of the submissions questioned the validity of NSPI's forecasted fuel costs, while others focused on the high level of executive compensation, the strong first quarter earnings, power outages related to tree contacts, and the need for alternative or renewable energy sources.

[139] During the evening session, some of these same concerns were also raised. Presentations were made by two individuals on their own behalf, by a representative from each of the three main political parties in the province, and by a representative from the Canadian Federation of Independent Business ("CFIB"). Some of their comments are noted below.

[140] The Honourable Murray Scott, MLA, urged the Board to seriously consider the impact of the high increase being requested by NSPI and to consider how it will affect seniors, hardworking families, and businesses.

[141] Linda Power, representing the Nova Scotia New Democratic Party, presented a petition containing over 8,700 signatures, which asked the "Government of Nova Scotia to cancel the 8 percent tax on basic electricity and [calling] on the Utility and Review Board to approve no more electricity rate increases until Nova Scotia Power and the government are required to help individuals and families save money on their electricity bill." Ms. Power also stated that NSPI profits "should not be used for investments made by Emera outside the jurisdiction of this Board", and urged the Board to "highlight in [its] decision where

government and the utility can do more to enable Nova Scotians to save their family budget by significantly reducing their use of electricity".

[142] The Honourable Stephen McNeil, MLA, Leader of the Nova Scotia Liberal Party, emphasized the need for a long term plan from NSPI or the government on how to move away from the current dependency on fossil fuels with high, volatile prices. He also noted that expanding the use of renewable energy sources will require "an enhanced focus and investment on transmission infrastructure".

[143] Leanne Hachey, representing the CFIB and its 5,200 members in Nova Scotia, addressed three main points:

i) the inequity of cost allocation between customer classes as noted by the large difference in the Revenue to Cost (R/C) ratios between rate classes;

ii) the need to appoint a Small Business Advocate ("SBA") who is separate from the Consumer Advocate;

iii) the need to change existing legislation to ensure that the SBA representation is based on electricity usage (i.e. rate class 10 & 11), not on the number of employees within a small business.

[144] Ms. Hachey also emphasized the great value that was realized by having small business represented by an Advocate during this application, but noted that a separate SBA will be needed in the future.

[145] The Board takes the views of the public as expressed in these submissions, as well as its responsibility to protect the public interest, very seriously and has reviewed all of the material which was filed.

[146] With respect to some of the public's concerns noted above, enhanced vegetation management is being facilitated through an increased funding allocation by NSPI; increased utilization of renewable energy sources is being addressed through the IRP process and NSPI's compliance with the Province's Renewable Energy Standard; and potential savings in electricity usage by ratepayers are being addressed through various DSM initiatives which were the subject of a separate hearing held earlier this year in April 2008.

[147] Regarding the issue of a SBA, the Board recognizes the need for an advocate that is separate from the consumer (residential) group and will, in future proceedings, appoint a separate SBA. The Board appreciates Mr. Merrick's work in balancing the two assignments in this proceeding. Mr. Merrick will continue his role as the Consumer Advocate.

[148] With respect to the public's objections to any form of rate increase, while no one wants to see increases in rates for electricity, circumstances can occur which justify an increase in rates. In this specific rate application, significant escalation in the cost of fuel used for generating electricity has been identified as a primary factor in the proposed rate increases. Similar cost escalations have also been experienced by the general public in the form of fuel for home heating, fuel for transportation, and the overall cost of goods

and services that have been impacted by higher fuel costs. For the reasons outlined in this decision, the Board has concluded that the rate increases which result from the Agreement are reasonable and justified.

[149] The Board wishes to convey its appreciation for the time, effort and interest shown by those individuals who have expressed their views to the Board during this hearing.

12.0 COMPLIANCE FILINGS

[150] NSPI is directed to file a compliance filing no later than November 19, 2008.

[151] The formal intervenors must provide comments, if any, no later than November 26, 2008.

[152] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 5th day of November, 2008.

____
Peter W. Gurnham

____
Roland A. Deveau

____
Kulvinder S. Dhillon

APPENDIX - A
FORMAL INTERVENORS

Affordable Energy Coalition	Claire McNeil and Susan Nasser
Avon Valley et al. (Avon Valley Greenhouses Ltd.) (Canadian Salt Company Limited) (CKF Inc.) (Crown Fibre Tube Inc.) (Halifax Grain Elevator Limited) (High Liner Foods Incorporated) (Imperial Oil Limited) (Intertape Polymer Inc.) (J. D. Irving Ltd., Saw Mills Division) (Lafarge Canada Inc.) (Louisiana Pacific Canada Ltd.) (Maritime Paper Products Ltd.) (Michelin North America (Canada) Inc.) (Minas Basin Pulp & Power Company Ltd.) (Oxford Frozen Foods Limited) (Sifto Canada Corp.) (Statia Terminals Canada [A Valero LP Company])	Robert G. Grant, Q.C., Nancy G. Rubin and Mark Freeman
Canadian Manufacturers & Exporters	Ann E. Janega, Robert Patzelt, Q.C. and Kristin Harris
Consumer Advocate	John Merrick, Q.C., and William Mahody
Ecology Action Centre	Cheryl Ratchford and Janice Ashworth
Halifax Regional Municipality	Mary Ellen Donovan, Martin C. Ward, Q.C., Julian Boyle and Angus Doyle
Liberal Caucus Office (Nova Scotia)	Michel Samson and Ryan Grant
Municipal Electric Utilities Co-operative of Nova Scotia	Don Regan
New Democratic Party Caucus Office (NDP)	Frank Corbett, MLA and Richard D. Starr

NewPage Port Hawkesbury Limited and **Bowater Mersey Paper Company Limited**	George T. H. Cooper, Q.C., David S. MacDougall and James MacDuff
Province of Nova Scotia - Department of Energy	Stephen T. McGrath, Scott McCoombs and Richard Penny
Sierra Club of Canada	Bruno Marcocchio
Town of Lunenburg	Bea Renton
Quetta Inc.	John L. Reynolds, P. Eng.

APPENDIX - B

APPEARANCES AT THE PUBLIC HEARING - EVENING SESSION

Name	**On Behalf Of**
Charlotte MacKeeman	On her own behalf
The Honourable Murray Scott	The people of Cumberland South Constituency
Linda Power	NDP Caucus
The Honourable Stephen McNeil	As Leader of the Nova Scotia Liberal Party and as MLA for Annapolis
Leanne Hachey	Canadian Federation of Independent Business
Janice Ashworth	On her own behalf