David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

Dear Ms Walli:

Re: EB-2007-0905 GEC-Pembina-OSEA IRRs

Attached please find Ex. M-7.1, our responses to IRs from Board Staff

Sincerely,

David Poch

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

Board Staff Interrogatories for GEC

INTERROGATORY #1

1) On page 10, it states "Ms. McShane's estimated cost of capital for OPG's hydro operations is about 8%".

(a) How was this conclusion arrived at given Ms. McShane did not identify a separate cost of capital for OPG's hydro operations?

(b) Why is it concluded about 8% is "reasonable" based on Connecticut procurement for peaking capacity?

(c) Is it Mr. Chernick's opinion that a peaking plant in Connecticut is a good proxy for a baseload hydroelectric plant in Ontario?

(d) What generation type was the peaking plant in Connecticut?

Response

a) In Exhibit L-12-2, p. 3, Ms. McShane says

> Given the primarily baseload nature of the regulated hydroelectric operations and mitigation of the inherent hydrology risks of OPG's regulated hydroelectric operations the variance account, Ms. McShane views their level of business risk as similar to the benchmark low risk utility sample. Thus, a reasonable capital structure for the stand-alone hydroelectric operations on that basis would be similar to that of the sample, that is, a common equity ratio of approximately 45% at the benchmark ROE of 10.5%.

Using 6% debt for the rest of the capital structure, the average cost of the capital for the hydro operations would be $0.45 \times 10.5\% + 0.55 \times 6\% = 8.03\%$.

b) My point was that both peaking plants under 30-year cost-of-service contracts in Connecticut and baseload hydroelectric plants in Ontario are relatively low-risk generators.

c) See (b).

d) The proposed peaking plants are combustion turbines, mostly dual-fueled (gas and ultra-low-sulfur diesel oil) but including two oil-only units, and including aero-derivative (LM6000 and LM2500), frame (Siemens STG6-5000F) and hybrid (LMS100) technology.

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INTERROGATORY #2

2) On page 10, it states McShane estimated a 25 basis point increase in ROE would be required in the absence of the 25% fixed payment for nuclear. How did Mr. Chernick arrive at the conclusion that "since nuclear represents only 45% of OPG investment" then the entire nuclear risk would be four-fold higher than 25 basis points (or 100 basis points)? Also, please explain why Mr. Chernick then states on page 11 that the 25% fixed payment for nuclear would reduce the cost of capital by 32 basis points.

Response

The question conflates two adjustments.

First, I started with Ms. McShane's estimate that offloading 25% of nuclear revenue risk onto ratepayers would reduce OPG's composite required return of equity by 25 basis points. Assuming that the risk-return relationship is linear, I extrapolated 100% of the nuclear revenue risk to 100 basis points on OPG's composite required return of equity.

Second, I recognized that the 100 basis points on OPG's composite required return of equity is not due to all of OPG's capital investment, but only the 45% of its investment that is nuclear. If 45% nuclear investment imposes revenue risk worth 100 basis point, 100% nuclear investment (e.g., in OPG's nuclear division, not mixed with the hydro operations) would impose risks worth 100 ÷ 0.45 = 222 basis points.

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INTERROGATORY #3

3) On page 9, it states OPG's proposals for nuclear (fixed payment, nuclear fuel variance account) would transfer the risk from OPG to consumers but the ROE should not be reduced to reflect that transfer of risk. The rationale appears to be so that OPG will make future nuclear investment decisions that are appropriate. Please explain why the Board should make its decision on an appropriate ROE for OPG's existing nuclear operations based on how it affects future nuclear investments and not on the degree of risk OPG would bear (transferred or not)? Also, why would it be appropriate for consumers to both assume these risks and compensate OPG for the same risks?

Response

My preference is that risks be retained by the utility. Apart from those matters where Regulation 53/05 requires the transfer of risk to the ratepayers, it is my recommendation that deferral accounts be avoided so that the corresponding increase in the allowed return better reflects the true risk of OPG's business activities.

Where deferral accounts are mandated, I am not proposing double recovery. For risks covered by deferral accounts, customers will bear the cost of adverse outcomes in any scenario. The issue is whether OPG should be reimbursed for having incurred an expense after the fact or be compensated in advance. My recommendation is that they be compensated in advance by way of a cost of capital reflecting the risk so that they can better gauge the desirability of incremental investments. If the Board adopts my recommendation it would be appropriate to track the added retained earnings and offset these against any subsequent costs that are eligible for deferral account treatment (by a corresponding reduction in the return at that time).

As I discuss in the cited reference, this would not be a suitable approach for a private entity as there would be no assurance that the retained earnings would be available and the lower return at that time could be challenged as 'unreasonable'. However, for a 100% publicly owned entity it is a feasible approach that shields OPG against sudden misfortune (the presumed intent of the regulations) while maintaining the salutary effects of a return more accurately reflecting the real business risks.

The risks should affect decisions regarding both existing nuclear investments (such as whether to continue operation of a marginally cost-effective unit) and new nuclear investments. The Board should be explicit in its expectation that OPG's decisions reflect the higher risks reflected in the return.