ONTARIO ENERGY BOARD

EB-2013-0321

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.

SUBMISSIONS OF ENVIRONMENTAL DEFENCE AND COMPENDIUM OF SELECT MATERIALS

August 21, 2014

KLIPPENSTEINS
Barristers & Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5

Murray Klippenstein
Kent Elson
Tel: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

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Overview

1. In this application, Ontario Power Generation ("OPG") is seeking to increase its charges by a very significant 23.4 percent.[1] This amounts to a yearly increase of $63.72 for a typical residential customer.[2] Large amounts are at stake: OPG is requesting over $9 billion in revenue for 2014-2015 from ratepayers.[3] OPG is also requesting approval of its contracting strategies for its proposed refurbishment of the Darlington Nuclear Generating Station ("Darlington").

2. Issues 4.11 and 4.12: Environmental Defence respectfully submits that OPG's contracting strategies for the Darlington refurbishment are contrary to the Government's Long-Term Energy Plan and expose Ontarians to too much risk. OPG has not allocated risk to its contractors as instructed by the Ontario Government. Instead, it has retained the vast majority of the risk itself. According to the evidence, OPG bears the "primary risk" of cost overruns with respect to over **93%** of the project costs.[4]

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[1] OPG Written Argument in Chief, July 28, 2014, p. 2.
[2] *Ibid.*
[3] Administration & Overview – Approvals (Ex. A1-2-2, p. 1.)
[4] See paragraphs Hearing Transcript, July 17, 2014 (Vol. 15), p. 56, 56 [see Compendium tab 2]; Contracting Strategy for Retube and Feeder Replacement (Ex. D2-2-1, Attachment 6-2), p. 8, 14 [see Compendium tab 3]; see also paragraphs 11 to 16 and the sources cited therein.

3. On average, nuclear projects in Ontario have gone 2.5 times over budget.[5] Darlington itself came in at a staggering 4.5 times higher than expected.[6] Based on this track record, the $12.9 billion refurbishment price tag, and the high degree of cost overrun risk assumed by OPG, the risks are unacceptably high and contrary to the Long-Term Energy Plan principles.

4. These submissions also address the following issues:

   a. Issue 4.9: OPG's request to include $228 million of Darlington refurbishment ancillary project costs into rate base is contrary to the Board's rate-making principles. Those projects would not be required but for the refurbishment, which has not received final governmental approval and is far from being in service.

   b. Issue 4.10: The Darlington refurbishment capital costs are unreasonable because the forecast cost of power from Darlington (8.9 cents per kWh based on OPG's "high confidence" estimate) is far higher than the cost of other sources of power (e.g. 3.5-4 cents per kWh for conservation; as low as 3 cents per kWh for Quebec hydro power imports).[7]

   c. Issue 6.3: The Pickering operations maintenance and administration ("OM&A") costs are unreasonably high. Pickering's OM&A costs alone (not including capital) are 8.16 cents per kWh – far higher than the other sources of power (e.g. conservation and hydro imports from Quebec).[8]

   d. Issue 3.1: Fifty to sixty per cent of the cost of the newly regulated hydroelectric facilities is attributable to a paper revaluation of those assets – not to actual capital spending on generation facilities.[9] OPG should be provided with a lower rate of return on this paper revaluation portion of the assets. Otherwise OPG will be awarded with unwarranted windfall income contrary to the Board's rate-making principles.

[5] See paragraph 19 below and the sources cited therein.
[6] *Ibid.*
[7] See paragraphs 46 to 48 below and the sources cited therein.
[8] See paragraphs 51 to 52 below and the sources cited therein.
[9] See paragraph 56 below and the sources cited therein.

5. Select evidence excerpts cited in these submissions are contained in the attached compendium of materials. The PDF version of the compendium contains electronic bookmarks corresponding to the compendium tab numbers referenced in the citations.

Darlington Refurbishment Strategy: High risk & contrary to Ontario's Long-Term Energy Plan

6. Environmental Defence requests that the Ontario Energy Board (the "Board") reject OPG's contracting strategy because it is contrary to the Government's Long-Term Energy Plan and it exposes Ontarians to far too much risk. The following factors are addressed below:

   a. OPG has retained the vast majority of the risk associated with the project;

   b. OPG and its predecessor have a track record of massive cost overruns in nuclear projects of this size;

   c. OPG's incentives do not align with ratepayer and taxpayer interests; and

   d. OPG's approach is contrary to Government directives.

<u>Background</u>

7. The Darlington Refurbishment Project is currently in the definition phase. [10] OPG's current "high confidence" estimate of the cost of Darlington Refurbishment Project is $12.9 billion.[11] A final "release quality" estimate will be developed in 2015.[12] The decision on whether or not to proceed with the project will occur following the release of the final estimate.[13] OPG has asked the Board to approve its proposed contracting strategies at this stage, prior to the development of the final release quality estimate.

8. The relevant issues from the Board's approved issues list are as follows:

> 4.11 Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

[10] Capital Projects, Nuclear, Darlington Refurbishment (Ex. D2-2-1) p. 11.
[11] Darlington Refurbishment Business Case (Ex. D2-2-1 attachment 5) p. 2.
[12] Capital Projects, Nuclear, Darlington Refurbishment (Ex. D2-2-1) p. 12.
[13] *Ibid.*

> 4.12 Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

9. The Long-Term Energy Plan sets out seven principles that the nuclear refurbishment process must adhere to. All of the principles are geared toward the minimization of cost and schedule risk to ratepayers and taxpayers. The most relevant principles for OPG's contracting strategies are as follows:

> 1. **Minimize commercial risk on the part of ratepayers and government.**
>
> 3. Entrench appropriate and realistic off-ramps and scoping;
>
> 5. **Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price.**
>
> 6. Make site, project management, regulatory requirements and supply chain considerations, and **cost and risk containment**, the primary factors in developing the implementation plan. [emphasis added][14]

10. The seven principles *do not* mandate an equal balancing between cost and risk nor do they mandate risk neutrality. Instead, they clearly require OPG to be *risk averse*. In particular, they require that risk be "minimized" and that contractors be held to their schedule and price estimates. As detailed below, OPG has not followed these clear governmental directions.

OPG retains the vast majority of the risk

11. OPG's contracting strategy allocates the vast majority of the risk associated with the project to ratepayers and taxpayers. Because the Government of Ontario is OPG's sole shareholder, any risk borne by OPG is ultimately borne by ratepayers or the government.[15] According to its own evidence, OPG bears the primary risk with respect to **over 93%** of the project costs.[16] That is because **less than 7%** of the project costs are under a fixed pricing model.[17]

[14] Government of Ontario, Long-Term Energy Plan, 2013, p. 29.
[15] Hearing Transcript, July 15, 2014 (Vol. 13) p. 170, lns. 4-7 [Compendium tab 5].
[16] Hearing Transcript, July 17, 2014 (Vol. 15), p. 56 - 57 [Compendium tab 2]; Contracting Strategy for Retube and Feeder Replacement (Ex. D2-2-1, Attachment 6-2), p. 8, 14 [Compendium tab 3].
[17] *Ibid.*

12. Aside from the 7% fixed pricing elements, the remainder of the project costs are for (1) OPG's own project management, (2) cost reimbursable contracts, and (3) target pricing contracts, which are discussed in turn below. OPG bears all the risk with respect to OPG's project management costs as the cost overruns would be on OPG's own work. This is very significant since OPG would be responsible for the overall project management and would be actively involved in the scoping of each project component. OPG also bears essentially all the risk with respect to cost reimbursable contracts as contractors would simply be reimbursed for reasonably incurred expenses, regardless of whether they are beyond the budgeted amounts.[18]

13. Under the target pricing model contractors are given incentives to meet cost targets. If those targets are missed, contractors will lose predefined incentive fees. *However, even if targets are missed, contractors will be paid for reasonably incurred direct expenses*.[19] Therefore, in OPG's own words it still bears the "primary" and "ultimate" risk with respect to these target pricing contracts.[20] This is highly problematic. Under this model, if an unforeseen obstacles arise, OPG will be responsible for paying the resulting costs.

14. For example, over 50% of the contracted work consists of the Retube and Feeder Replacement, most of which is under this problematic target pricing model. [21] Concentric Energy Advisors raised the following concern with respect to this critical element of the project: "once the cost for each unit exceeds the target price and caps for each unit, the contract is essentially a cost reimbursable (excluding vendor overhead and profit) agreement".[22] Again, if costs increase above the targets the contractor will lose incentive payments (i.e. profits and overheads). *However*, the contractor will still be paid for reasonably incurred project expenses. Also, once all incentive payments have been lost, the contractor will have little to no incentive to slow the growth of costs.

[18] Darlington Refurbishment Program Commercial Strategy (Ex. D2-2-1 attachment 6-1) p. 16 [Compendium tab 4].
[19] Hearing Transcript, July 16, 2014 (Vol. 14) p. 53, ln. 11 to p. 54, ln. 25 [Compendium tab 6]. Although OPG is not responsible for contractor work defects, it is responsible for any reasonably incurred costs, such as those resulting from unforeseen problems. Furthermore, even contractor work defects could be expensive to resolve if contractors dispute the cause of the cost overrun.
[20] Contracting Strategy for Retube and Feeder Replacement (Ex. D2-2-1, Attachment 6-2), p. 8, 14 [Compendium tab 3].
[21] Hearing Transcript, July 16, 2014 (Vol. 14) p. 43, lns. 23-28, p. 55, lns. 4-11 [Compendium tab 6].
[22] Concentric Energy Report, p. 9 [Compendium tab 7].

15. If costs rise above targets OPG will experience some savings through decreased incentive payments to contractors. However, those incentive payment savings would be relatively small. If contractor costs increase by 50%, a full **81%** of the contractor cost overruns would be passed on to OPG even after accounting for the savings from decreased incentive payments.[23] If all costs (including OPG's refurbishment costs) increase by 50%, over **90%** of the total cost overruns would be borne by OPG.[24]

16. To summarize, over 93% of the project costs are from cost reimbursable or target pricing contracts or are OPG's own costs. As a result, the vast majority of the project cost overrun risk is borne by OPG, and in turn by ratepayers and taxpayers.

17. Furthermore, OPG's plan also fails to protect ratepayers and taxpayers from risks associated with schedule slippage, including:

   a. Potential lost income due from out-of-service units;

   b. Increased financing charges; and

   c. The cost of replacement power.

18. Further still, under OPG's plan, the Ontario Electricity Financial Corporation (and by extension, the Government of Ontario) assumes additional risk by providing financing at preferential rates.[25]

<u>Track record of massive cost and schedule overruns</u>

19. OPG and its predecessor have a track record of massive cost and schedule overruns when it comes to nuclear projects of this magnitude. For example, OPG acknowledges that the cost of returning Pickering 4 to service was **2.7 times** over budget and that the cost of building Darlington was **4.5 times** over budget.[26] On average, nuclear projects in Ontario have gone 2.5 times over budget.[27] Based on this track record, the risk of significant cost

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[23] Response to ED Interrogatory No. 11, p. 11 [Compendium tab 8].
[24] Response to Undertaking J14.2, attachment [Compendium tab 10] (OPG would bear over 91% of the cost overruns if it is assumed that contingency is removed to reduce cost growth. OPG would bear over 93% of the cost overruns if cost growth is applied to contingency amounts.)
[25] Hearing Transcript, July 16, 2014 (Vol. 14) p. 14, lns. 7-9 [Compendium tab 6].
[26] Hearing Transcript, July 15, 2014 (Vol. 13) p. 167, lns. 5-6 & p. 168, lns. 14-16 [Compendium tab 5].
[27] Ontario Clean Air Alliance Research Inc., *Appendix A: Ontario's History of Nuclear Cost Overruns and Ontario Hydro's Stranded Nuclear Debt* [Compendium tab 9]; Hearing Transcript, July 15, 2014 (Vol. 13) p. 156, lns. 4-19 (Note, OPG challenged the figure of $213 M used by the OCAA for the Pickering A restart estimate, arguing that

overruns is very high. There is a real likelihood that taxpayers and ratepayers could be saddled with **billions or even tens of billions** of dollars in unexpected costs.

20. OPG asserts that it has recently completed other projects within budget. However, the examples provided by OPG pale in comparison to the Darlington refurbishment. The largest of these purported successes had a cost of $350 million, a far cry from the $12.9 billion refurbishment project. [28] Furthermore, OPG has gone far over budget on other recent projects, including the Niagara Tunnel Project and the Campus Plan Project. The 50% cost overrun on the Campus Plan Project is particularly troublesome seeing as it is part of the Darlington refurbishment itself.

21. OPG does not appear willing to fully acknowledge its own track record or the inherent risks associated with large nuclear projects. OPG's Senior Vice President of Nuclear Projects stated as follows on cross-examination:

> [I]t isn't a good practice to use history as the indicator for how the Darlington refurbishment project will get executed. So I think the approach for how we are managing that project needs to stand on the basis of the evidence we have provided, and **I would not draw any conclusions around history of other projects** to parallel that. [emphasis added][29]

22. By not acknowledging the history of massive nuclear cost overruns, or the significance of that track record, OPG underestimates the inherent risks in projects such as this.

OPG's incentives do not align with ratepayer or governmental interests

23. OPG's incentives are not aligned with ratepayer or governmental interests. If the government does not proceed with the Darlington refurbishment, OPG would stop producing nuclear power in roughly six years.[30] Approximately 60 percent of OPG's employees are on the nuclear side.[31] It is very much in their interest, and OPG's organizational interest, to have Darlington approved. To improve the chances of approval, OPG and its staff and management have a strong incentive to at least downplay the risks associated with this project.

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the OPG Board approval was based on a $900 M cost estimate. However, on cross-examination, OPG's witness acknowledged that the original 1999 OPG Board approval was indeed based on a $213 M estimate. See p. 162-163).

[28] Hearing Transcript, July 15, 2014 (Vol. 13), p. 168, ln. 25 to p. 169, ln. 6 [Compendium tab 5].

[29] Hearing Transcript, July 15, 2014 (Vol. 13), p. 161, lns. 6-12 [Compendium tab 5].

[30] Hearing Transcript, July 16, 2014 (Vol. 14), p. 33, lns 7-20 [Compendium tab 6].

[31] Hearing Transcript, July 16, 2014 (Vol. 14), p. 34, lns. 3-12 [Compendium tab 6].

24. In addition, OPG also has a strong incentive to assume risk itself rather than pay high risk premiums. If fair market risk premiums were included in the Darlington refurbishment cost estimates, the government might decide not to proceed (as occurred with the now-suspended Darlington new build project). By assuming risk itself and avoiding private sector risk premiums, OPG can superficially lower the overall Darlington cost estimate, thus improving the likelihood of governmental approval.

25. This is *not*, in any way whatsoever, intended to impugn the integrity of OPG's witnesses. Instead, the above comments are important because OPG's organizational interests have a bearing on the Board's role as regulator and how stringently it should assess OPG's application. OPG's incentives also may assist in understanding why OPG would go to great lengths to avoid incurring private sector risk premiums.

26. In our submission, the importance of Board oversight is greatly heightened in this case because OPG's incentives do not align with ratepayer or governmental interests. Therefore, in our submission, the Board and parties should be vigilant to ensure that OPG is not downplaying the risk of this project or assuming risk itself to avoid risk premiums.

OPG's approach is contrary to Government directives.

27. As noted above, the Long-Term Energy Plan requires OPG to minimize commercial risk on the part of ratepayers and the Government and to hold contractors accountable to their cost and schedule estimates (see paras. 9 & 10 above). OPG's plan is contrary to these directives.

28. First, very simply, OPG has retained far too much risk, as outlined in paragraphs 11 to 18 above.

29. Second, and more fundamentally, OPG's contracting strategy is based on principles that conflict with the Long-Term Energy Plan principles. In particular, OPG states that its strategy is "to allocate risk to the party most able to manage that risk."[32] Although that may sound initially prudent and reasonable, the result is that only a very small proportion of risks are allocated to contractors (less than 7% is fixed pricing). The problem may lie in the fact that OPG believes that OPG itself is the party best able to manage risk on parts

[32] OPG Written Argument in Chief, July 28, 2014, p. 44 & 48.

of the project where "unforeseens" might arise. The following comments from OPG's Vice President of Nuclear Operations are illustrative:

> MR. ELSON: Why would it be reasonable to make OPG liable for those unforeseens, but not have the contractors be liable for those unforeseens?
>
> MR. REINER: Well, OPG is actually in the best position to assess what that unforeseen might entail. OPG is the owner of the asset. We've got the technical expertise to assess what the impacts of the condition of specific components might be on the future reliable operation of the plant.[33]

30. The Long-Term Energy Plan *does not* direct OPG to allocate risk to the party most able to manage that risk. The Government of Ontario could have used that criteria, but chose not to. Instead, it directed OPG to *minimize* risk to ratepayers and the government and to hold contractors accountable to price and schedule. That direction is different and more risk-averse than the principle applied by OPG.

31. Stated in economics terms, allocating risk to the party most able to manage risk is "risk-neutral" because it is indifferent between allocating risk to OPG or its contractors. This conflicts with the Long-Term Energy Plan, which mandates that OPG be risk averse. Furthermore, to the extent that OPG underestimates the risks or overestimates its own ability to manage risk (as discussed above), it will assume far too much risk by allocating risk to the party it believes is best able to manage it.

32. Finally, OPG's contracting strategies are out-of-step with other power generation procurement in Ontario. For example, Ontario Power Authority's electricity supply contracts for renewable and natural gas-fired generation projects do not allow for construction cost overruns to be passed on to ratepayers. Similarly, the Government of Ontario sought to contract for the Darlington new build on a turnkey basis to insulate ratepayers from cost overrun risk. These other procurement processes are an indication of the amount of risk protection the government is seeking through the Long-Term Energy Plan principles. However, OPG did not look to these models in developing its contracting strategies for Darlington.[34]

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[33] Hearing Transcript, July 15, 2014 (Vol. 13), p. 173, lns. 4-12 [Compendium tab 5].
[34] Hearing Transcript, July 16, 2014 (Vol. 14) p. 9, lns. 5-25 & p. 62, lns. 17-25 [Compendium tab 6].

Options to reduce risk

33. OPG has not fully explored other options to reduce risk. OPG argues that completing all or large parts of the project on a fixed price basis would be prohibitively expensive. OPG also doubts the willingness of contractors to enter into such agreements. However, OPG admits that it did not enter into negotiations with *any* contractors to determine the cost of a fixed price contract.[35]

34. Although Concentric Energy Advisors concludes that a turnkey agreement is "not likely to be commercially feasible," they do not rule out the possibility.[36] Also, their assessment of SNC Lavalin's expected interest is based on an ambiguous quote by SNC Lavalin's Executive Vice President in a 2011 *Canadian Business* article.[37] Concentric staff did not make any inquiries with SNC Lavalin directly.[38] OPG and its consultants have not taken sufficient steps to determine the availability or the potential cost of fixed price agreements.

35. OPG also points to the difficulties faced with the fixed-price, turnkey strategies used at Point Lepreau and Wolsong to suggest that fixed price agreements are undesirable. However, Concentric Energy Advisors concluded that Wolsong "represents the most successful (e.g., cost and schedule performance) CANDU refurbishment project yet."[39] Also, at Point Lepreau, the fixed-price, lump sum, turnkey strategy "largely protected NB power from cost overruns."[40] Although schedule slippage occurred at Point Lepreau, OPG does not appear to have explored ways to overcome those difficulties while retaining the lump-sum model.[41] Based on the experience at Wolsong and Point Lepreau, OPG should not rule out a fixed-price, lump sum, turnkey strategy.

36. Regardless, even if a fixed-price turnkey strategy is unattainable or undesirable, there is a large gulf between a turnkey strategy and the high amount of risk that OPG assumes in its current proposal. For example, OPG could seek firm caps in its contracts stating that

[35] Hearing Transcript, July 16, 2014 (Vol. 14) p. 41, lns. 1-12 & p. 51, lns. 5-6 [Compendium tab 6].
[36] Concentric Energy Report, p. 8 [Compendium tab 7].
[37] *Ibid.*
[38] Hearing Transcript, July 16, 2014 (Vol. 14) p. 49, lns. 10-14 [Compendium tab 6].
[39] Concentric Energy Report, p. 5 [Compendium tab 7].
[40] *Ibid.*, p. 7.
[41] *Ibid.*

OPG would not reimburse any expenses beyond, say, 10% over the budgeted amounts. Alternatively, OPG could endeavor to greatly increase the proportion of the project under a fixed price model from under 7% to, say, 70% of the overall costs.

37. For the above reasons, Environmental Defence requests that the Board reject OPG's contracting strategies.

Darlington Refurbishment Rate Base Increases: Contrary to rate-making principles

38. OPG is requesting approval to add over $228 million in costs to rate base for a series of projects that are ancillary to the Darlington refurbishment.[42] Issue 4.9 asks whether these proposed test period in-service additions are appropriate. Environmental Defence submits that they are not.

39. OPG's request is contrary to the basic rate-making principle that ratepayers should only pay for "used and useful" assets that are required and prudent. Although there is some evidence that the assets will be *used* in 2014-2015, OPG has not established that these asserts would be *required* "but for" the refurbishment project. These projects are properly characterized as ancillary to the refurbishment, and should not be included in rate base until the refurbished units are in service.

40. For example, OPG plans to add $45 million to rate base for the Darlington Operations Support Building Refurbishment project.[43] However, OPG acknowledges that it would not be required but for the refurbishment. OPG's Vice President of Nuclear Operations stated as follows: "if we were running the station to the end of life, we would probably find ways to avoid making the investment in that facility."[44] Similarly, the $83 million Safety Improvement Opportunities are "part of the Environmental Assessment for the Refurbishment."[45] These is no evidence that these would be required if Darlington was to shut down in 2020.

[42] OPG Argument in Chief, July 28, 2014, p. 55.
[43] *Ibid*.
[44] Technical Conference Transcript, July 8, 2014, p. 78, ln. 15 to p. 79, ln. 14 [Compendium tab 11].
[45] Response to Undertaking JT3.5, p. 2 [Compendium tab 12].

41. The fact that these facilities might be *in use* in 2014-2015 is not sufficient for their costs to be included in rate base. Facilities must also be required and prudent to be included in rate base. The Alberta Court of Appeal described this principle as follows:

> **[M]ere use is not sufficient to burden consumers with the cost.** Clearly the consumer need not bear all the costs of an asset which is used if, for example, it reflects an imprudent expenditure. Assets unnecessarily used are not, simply by use, put into the rate base. Without putting too fine a point on interpretation we conclude that **even if an object is used it must also be required.**[46]

42. As a matter of rate-making principle and intergenerational equity, ratepayers are not required to pay for assets they are not benefiting from. The Darlington refurbishment ancillary projects will only provide benefit to ratepayers as part of the overall Darlington refurbishment project, and should not be included in rate base at this time. An exception to standard rate-making principles is particularly unjustified seeing as the cost of power from refurbished Darlington reactors is likely to be significantly higher than other sources of power such as conservation and hydro power imports from Quebec, as detailed in paragraphs 46 to 48 below.

43. OPG's request is also inconsistent with the Board's ruling in EB-2010-0008. In that decision the Board rejected OPG's request to include construction work in progress ("CWIP") in rate base. The Board held that: "OPG's request for CWIP is premature, given that the DRP is only at the definition stage."[47] The DRP is still in the definition phase.[48] Including the ancillary projects in rate base now would be inconsistent with regulatory practices and could prove problematic if the project is not ultimately approved by the Government of Ontario.

Pickering & Darlington: Far more costly than other power sources

44. As detailed below, Environmental Defence submits that the 2014-2015 costs requested by OPG in relation to Pickering OM&A and the Darlington refurbishment capital projects

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[46] *Alberta Power Ltd. v. Alberta Public Utilities Board* (1990), 66 D.L.R. (4th) 286 (leave to appeal to the Supreme Court of Canada refused), as cited in Alberta Energy and Utilities Board Decision 2002-072 (ATCO Gas Transfer of Carbon Storage Facilities), p. 20 (At page 21, the Alberta Energy and Utilities Board affirmed that this principle applies to the "used and useful" test and added that "[t]he term 'used and useful' does not only refer to needed capacity, but also reflect that the property in question is economically desirable.") [Compendium tab 19]
[47] Decision with Reasons, EB-2010-0008 (OPG Payment Amounts 2011-2012), p. 78 [Compendium tab 18].
[48] Ex. D2-2-1, p. 11.

are unreasonable because other power sources are far more cost-effective. In our submission, this kind of cost-effectiveness comparison is a relevant factor to consider in determining the reasonableness of OPG's requested costs, including for the following three reasons:

a. First, it is reasonable and in the best interests of ratepayers to expect OPG to strive to produce power at a cost that is at least equivalent to other sources of power. By considering this factor, the Board will encourage OPG to strive for comparative cost-effectiveness.

b. Second, it could be potentially unfair to ratepayers to allow OPG to charge far more for its power than the cost of power available from other sources.

c. Third, OPG itself makes the same kind of cost-effectiveness comparisons in its application.[49]

45. Environmental Defence acknowledges that it is not the Board's role in this proceeding to decide on the supply-mix in Ontario. Environmental Defence also acknowledges that it is not the Board's role to decide on the future of Pickering or the Darlington refurbishment. For example, the Board clearly could not disallow all spending relating to the Darlington refurbishment. However, the Board has the jurisdiction to set OPG's payment amounts and, for example, to reduce the allowable amounts so that they are more in line with the cost of other sources of power. Comparative cost-effectiveness is one of the factors the Board can consider in assessing OPG's application.

Darlington refurbishment capital costs

46. OPG is seeking approval to spend $1.682 billion in 2014 and 2015 on the Darlington refurbishment project. Issue 4.10 asks whether these expenditures are reasonable. Environmental Defence submits that they are not. This is an additional reason why OPG should not be granted special permission, contrary to normal regulatory practices, to include Darlington refurbishment costs into rate base in 2014-2015.

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[49] See e.g. Ex. A1-3-1, p. 4, ln. 21 to p. 5, ln. 5.

47. Based on OPG's current "high confidence" cost estimate, the Levelized Unit Electricity Cost ("LUEC") from refurbished Darlington units will be 8.9 cents per kWh.[50] However, there are a number of reasons to believe the actual LUEC will be higher.

a. First, the LUEC would be much higher if the forecast price included the risk premiums that a private sector company would demand. OPG considered a fixed-pricing model but decided that the risk premiums required by private contractors would simply be too high.[51] By assuming the majority of the risk for this project, and avoiding high risk premiums, OPG has superficially lowered the cost estimates.

b. Second, because this project is highly capital intensive, the LUEC would be much higher if it was calculated based on the higher cost of capital that a non-regulated private entity would face. [52] This would provide a more accurate comparison with other power generation options.

c. Third, large nuclear projects have gone on average 2.5 times over budget.[53] A 2.5 times cost overrun scenario would result in a LUEC of 16.6 cents per kWh.[54]

d. OPG asserts that this scenario is unreasonable because it assumes that OPG's own project management costs will grow (not just contractor costs). However, there is no reason to believe that OPG's own project management costs are immune from cost overruns. OPG also argues that it is "artificial" to assume cost growth in the amounts set aside as "contingency." However, contingency amounts are "costs that will probably occur based on past experience" and therefore it is not unreasonable to assume that they would be subject to some cost growth.[55] Regardless, even if the contingency amounts are assumed to "absorb" the cost overruns, a 2.5 times cost overrun scenario would still result in a LUEC of 13 cents per kWh.[56]

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[50] Response to Undertaking J14.4 [Compendium tab 13] (Note: This estimate is in $2014 and is based on an assumed 82% annual capacity factor. This assumption is reasonable seeing as Darlington's average annual capacity factor since it commenced operations is 83.34% - see J14.3.).
[51] Hearing Transcript, July 16, 2014 (Vol. 14) p. 11, lns. 3-7 & p. 41, lns. 1-12 [Compendium tab 6].
[52] A private company's cost of capital for a project such as this would be higher than OPG's. See Hearing Transcript, July 16, 2014 (Vol. 14) p. 27, ln. 16-20 [Compendium tab 6].
[53] See discussion in paragraph 19 above.
[54] Response to Undertaking J14.2, attachment 14.2a. Note, this
[55] Modus Energy Advisors Report, p. 6 (Ex. D2-2-2, attachment 1).
[56] *Ibid*. attachment 14.2b

48. In comparison, the cost of electricity conservation is only 3.5 to 4 cents per kWh.[57] This is less than half of OPG's estimate of the cost of power from the Darlington refurbishment. In addition, Quebec is currently forecast to export 20.1 TWh of power at 3 cents per kWh hour in 2014 and 31.1 TWh at that same low price by 2022.[58] Even a deal with Quebec at double those existing prices would be considerably lower than the cost of power from the Darlington refurbishment. In addition, energy conservation and hydro power imports from Quebec are not subject to the high cost overrun risks facing Darlington.

Pickering OM&A costs

49. OPG is seeking approval to spend over $1 billion on Pickering OM&A expenses in 2014-2015.[59] Issue 6.3 asks whether these expenditures are reasonable. Environmental Defence submits that they are not. Environmental Defence requests that the Board disallow a portion of these expenses such that Pickering's costs are more in line with the cost of power from other sources.

50. In 2008 Pickering was the highest cost nuclear plant in North America in terms of non-fuel operating costs.[60] In 2011, Pickering continues to be in the worst quartile (i.e. highest cost quartile) among nuclear plants in North America.[61] Other intervenors will be addressing benchmarking against other nuclear producers in much more detail.

51. The cost of power from Pickering is much higher than non-nuclear sources of power. Pickering's operating costs per kWh are extremely high – OPG forecasts OM&A costs of 8.16 cents per kWh in 2014.[62] Again, this figure is for OM&A alone - it does not include capital costs. In comparison, as noted above, the cost of conservation is 3.5 to 4 cent per kWh and the cost of Hydro power from Quebec could be as low at 3 cents per kWh.

52. Furthermore, a significant amount of the cost of the alternative power to Pickering would come at little or even no cost because the continued operation of that generating station

[57] OPA Evidence, p. 12 [Compendium tab 14].
[58] Québec Commission on Energy Issues, *Mastering Our Energy Future*, February 14, 2014 [Compendium tab 15].
[59] Ex. F2-2-1, table 1 (Note: OPG's OM&A costs for Pickering would be far more than $1 billion including its allocation of corporate overhead and other shared costs.).
[60] Hearing Transcript, June 19, 2014 (Vol. 6), p. 140, ln. 8 to p. 141, p. 1.
[61] Ex. F2-1-1, p. 5.
[62] Response to Undertaking JT1.14, p.2 [Compendium tab 16].

will require “spilling” hydro power and curtailing other renewable power (i.e. due to the excess power produced by Pickering). Curtailed renewables would be a free source of power for Ontario in an economic sense since the marginal cost to the economy of actually using this power would be essentially zero. In 2014 and 2015 alone, the operation of Pickering will require the displacement or curtailment of:

a. 624 GWh of water power;

b. 408 GWh of wind power;

c. 108 GWh of power from combined heat and power plants;

d. 36 GWh of biomass power; and

e. 24 GWh of solar power.[63]

53. In light of the above, in our submission, the amounts requested by OPG are unreasonably high and therefore unfair to ratepayers.

Newly Regulated Hydro Facilities: Windfall income should not be awarded

54. OPG seeks to add $2.511 billion to rate base in 2014 in relation to the newly regulated hydroelectric facilities. Environmental Defence does not object to the amount OPG plans to add to rate base, which is mandated by O. Reg. 53/05. However, Environmental Defence submits that a portion of this amount should only receive a return equal to OPG’s long-term cost of debt. This relates to issue 3.1, which asks what the appropriate capital structure and rate of return on equity is.

55. O. Reg. 53/05 requires that the Board accept the value of these assets as set out in OPG’s financial statements. However, it is silent on the rate of return on those assets. That issue is clearly within the Board’s discretion.

56. In 1999, Ontario Hydro valued its hydro assets at $2.755 billion.[64] In 2001, OPG valued those same assets at $7.754 billion – an increase of roughly $5 billion.[65] This increase is attributable to a revaluation of those assets from their historical actual costs, which

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[63] OPA Evidence, p. 13 [Compendium tab 14].
[64] Hearing Transcript, July 14, 2014 (Vol. 12) p. 130, lns. 3-11.
[65] *Ibid.* p. 130, lns. 12-19.

occurred as part of the transfer from Ontario Hydro to OPG.[66] In response to an undertaking, OPG acknowledged that roughly 50% to 60% of the current $2.5 billion value of the newly regulated hydroelectric facilities is attributable to that revaluation process.[67] In other words, the actual capital spending on those facilities minus depreciation would be less than half of the amount that will be added to rate base.

57. The Board's standard regulatory practice is to award a fair rate of return on the actual capital cost of a facility minus depreciation. This rate of return is meant to fairly compensate the utility for capital spending that benefits consumers. The normal rate of return should only be applied to the actual capital spending minus depreciation. It should not apply to the portion of the $2.5 billion that is attributable to the paper revaluation of these assets.

58. The 50 to 60% of the $2.5 billion that is attributable to this paper revaluation could be labelled as a Newly Regulated Hydro Rate Base Adder. Again, this Adder does *not* represent the capital spending on a generation facility and therefore should not receive the same rate of return. This Adder more akin to the assumption of a debt than actual capital spending on a generation facility. Therefore, in our submission, the Adder should receive a return equal to OPG's long-term cost of debt. If OPG is given a rate of return on the Adder as if it were actual capital spending, OPG would be receiving windfall income to the detriment of ratepayers.

59. In addition, Environmental Defence proposes that this issue be considered in the next payment amounts hearing with respect to the currently regulated hydroelectric assets. It may be that the Board would wish to make adjustments to the rate of return of those asserts to properly account for their true nature.

Conclusion

60. In conclusion, with respect to issues 4.11 and 4.12, Environmental Defence respectfully requests that the Board reject OPG's proposed contracting strategies on the grounds that they expose ratepayers and taxpayers to far too much risk and are contrary to the Long-Term Energy Plan principles.

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[66] *Ibid.* p. 130, ln. 20 to p. 133, ln. 3.
[67] Response to Undertaking J12.3 [Compendium tab 170.

61. Environmental Defence also requests that the Board:

a. Disallow OPG's proposed $228 million in service additions to the electricity customer rate base for the Darlington refurbishment ancillary projects (issue 4.9);

b. Reduce the amount for Pickering OM&A to be more in line with the cost of other power sources (issue 6.3); and

c. Approve a rate of return for the Newly Regulated Hydro Rate Base Adder (i.e. the 50 to 60% portion of $2.5 billion attributable to the revaluation) equal to OPG's long-term cost of capital (issue 3.1).

All of which is respectfully submitted this 21nd day of August, 2014.

Murray Klippenstein

Kent Elson

KLIPPENSTEINS
Barristers and Solicitors
160 John Street, Suite 300
Toronto, ON M5V 2E5

Murray Klippenstein, LSUC No. 26950G
Kent Elson, LSUC No. 57091I
Tel.: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

REDACTED
PUBLIC

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2013-0321**	
VOLUME:	**15**	**REDACTED - PUBLIC**
DATE:	**July 17, 2014**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Christine Long	**Member**
	Allison Duff	**Member**

MR. POCH: So just based on -- and these are -- these would be overnight costs?

MR. ROSE: These were overnight costs in 2013 dollars. That's correct.

MR. POCH: So they would be comparable to the $10 billion figure as opposed to the 12.9?

MR. ROSE: That is correct.

MR. POCH: Under an -- interest and escalation...

MR. ROSE: Are excluded from this estimate.

MR. POCH: Right. Okay. These would go up if we counted interest and escalation, but we're on an apples-and-apples basis.

So that would be 6.55 percent of the 10? 655 million?

MR. ROSE: That is 6.55 percent of the 10.

MR. POCH: So in other words, 93.45 percent of the cost estimate, of the $10 billion cost estimate, is either OPG cost or is under target -- in which case you bear the whole risk, or is target pricing with shared risk, or is still in the contingency and reserve pools; correct?

MR. ROSE: That is correct.

MR. POCH: Obviously you bear the risk?

MR. ROSE: There are some non-OPG costs, you know, insurance, fuel, that are not -- that are OPG's to pay, but they're not OPG labour. Just to clarify that.

MR. POCH: No, I understand. I'm just -- who is bearing the risk on these different pots? And so apart from that 6.55 percent, you're either bearing all of the risk or sharing the risk under the target pricing agreements?

MR. ROSE: Yes.

MR. POCH: Okay. So just to be clear, if we go back to that exhibit of the $15 million hypothetical contract -- 10 million in labour and materials and then 5 million in overheads and profit -- if scope changes occur and you renegotiate -- you therefore have to renegotiate -- and so the contractor hard costs change, the overhead and profits would presumably change, you would absorb all of that? That would be the expectation, that you would absorb all of that?

MR. ROSE: Yes.

MR. POCH: Okay. If there is an underestimate of work or materials, it turns out to be a more complicated job because of unforeseen factors, as I think is your position with the campus projects, all three categories go up, and again you absorb -- that is really the same thing? You're going to absorb it in that case?

MR. REINER: That's correct.

MR. POCH: Okay. And if the -- if we have, on the other hand, a cost increase driven by the contractor with the exception of warranty and rework, and they go up, that's what your -- we have discussed already today that is what the -- the penalties try to dissuade them from getting into that situation.

But if those costs were to exceed, in our little example of a $15 million contract, if those extra costs were to exceed the 5 million or even approach the

- Value for Money
- Responsible Management
- Geographical Neutrality and Reciprocal Non-Discrimination

The Contracting Strategy Core Team reviewed OPEX. See Appendix E for full details of OPEX reviewed,

The Team met between July and December 2009 to develop contracting strategy options and recommendations. The Team examined project related OPEX from other large projects (both internal OPG and external projects) including PARTS, Darlington VBO, Bruce A Restart, Point Lepreau, Brown's Ferry Restart, and Fort Calhoun Lessons Learned, BAA Terminal 5. Contracting and strategy background from Pickering A Units 1 and 4, contracting options completed for Pickering A Units 2 and 3, and analysis completed for Pickering B prepared by Faithful and Gould were also reviewed (See Appendix E).

In December 2009 the Team recommended strategies to the EVP Refurbishment for Retube and Feeder Replacement, Reactor Mock-Up, Fuel Handling & Turbine Generator Refurbishment, and Balance of Plant Refurbishment.

The Core Team expanded in 2010 to incorporate additional stakeholders including Commercial Strategy, Projects, and Finance. Additionally Faithful & Gould was engaged to provide third party support for contracting development.

As the Contracting Strategy progressed additional stakeholders were engaged including a Cross Functional Sourcing Team, Advisory Team, and Steering Committees.

The Contracting Strategy Team meetings and milestones are documented in Appendix A.

2.3.1.2 Retube and Feeder Replacement Strategy 2009

The contracting strategy recommended by the Contracting Strategy Team included specific strategy recommendations for Retube and Feeders based on the concept of OPG and its contractors working to a common set of goals and incentives. While OPG would retain ultimate control and risk, contractors would have an active role jointly developing methodology, constructability, price and schedule. Selection of contractors would be based on selecting the right partner rather than on price since scope, cost, and schedules at that time would be preliminary subject to a high degree of uncertainty.

Fundamental principles of this type of arrangement would include:

- Integrated co-located team

contracting model could have been a contractual partnership, corporation, or limited partnership with OPG retaining ultimate control and risk.

7.0 RECOMMENDED CONTRACTING STRATEGY

The recommended strategy was a partnering-based model where OPG and its contractor work to a common set of goals and incentives. Essential to the anticipated partnering arrangement is:

- Integrated co-located team
- Shared incentives, with OPG bearing the primary risk
- Clear common vision & project objectives
- Full transparency, based on open-book method
- Joint risk register
- Common IT and project management systems
- Integrated project reporting

The recommended contracting strategy was similar to the approach OPG took on the Lower Mattagami Redevelopment Project which incorporated a design-build target price and fixed fee pool. The base contract for RFR was based on the Lower Mattagami precedent.

In November 2010, Faithful and Gould prepared a report entitled "Benchmarking Report on Contracts Strategy and Overhead & Profit Levels for Large-Scale International Projects" to compare the RFR contracting approach to other large international programs across multiple energy sectors and geographic regions (see Appendix E). This report concluded that the contracting approach for RFR was in line with the overall contracting approach adopted on complex long term projects.

After receipt of the F&G report during the Prequalification process proposed Key Terms were reviewed and discussed with Proponents to gauge market acceptance of the proposed Terms. Some Proponent feedback was incorporated into the strategy and contract model prior to RFP issuance in March 2011.

8.0 CHOICE OF PRICING MODEL

Based on a shared goals and incentives a cost-reimbursable Target Price model incorporating fixed fee and incentive/disincentive components was recommended in December 2009. Specific components would be fixed price and incentives/disincentives would be paid on cost or schedule overruns or under-runs. OPG would pay actual costs (based on negotiated allowed costs) plus a base profit/fee. Contractors would have meaningful fee at risk.

Contractors would have the ability to earn enhanced profit based on contingency savings and would share any cost over-run based on an agreed-to formula. Incentives and disincentives would be assessed at various intervals during the course of the

b) Procurement Options

	Nature of Option
Request for proposals (RFP)	Buyer defines needs; vendors addresses all issues in response
Parallel negotiations	Negotiations with two (or more) selected vendors - can include staged procurement This may or may not be the result of an RFP
Single source	OPG and the vendor negotiate to an agreement after initial selection – can include strategic partnership or staged procurement Method for selecting the single source partner would have to be defined.
Staged Procurement	OPG and vendor(s) enter into a governing agreement setting a process to agree to a specification and contract, but services are procured in stages (e.g. engineering, procurement, etc.). The final decision to commence the project is made at a later date Staged procurement may or may not follow from an RFP process

c) Pricing Options

	Nature of Option
Fixed/Firm Price	Vendor promises to complete its work within a set budget and time period with consequences for failure to do so. Price only varies in specified circumstances or where OPG changes scope Firm price allows escalations
Guaranteed Maximum or Target Price	Contract is cost reimbursable, with a mark-up or fee, but parties have set targets for cost and schedule Parties share savings below targets, usually to a floor Parties share overruns above targets Incentive mechanisms which the vendor agrees to forfeit items such as overhead, profit or costs based on pre-defined conditions In a Guaranteed Maximum, vendor pays overruns over a total cap
Cost Reimbursable	Vendor is paid its actual labour and material costs with mark-ups for overhead and profit (which are usually a percentage of costs)

Ontario

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was the --

MR. ELSON: Page 1.

MR. KEIZER: Thank you.

MR. ELSON: This page contains an appendix A of the Darlington Rebuild Consumer Protection Plan. This is a report by the Ontario Clean Air Alliance Research Inc.

According to this report, every major nuclear project in Ontario's history has gone over budget, and the report provides examples of the original cost estimates and the actual costs for the ten listed projects, as well as the original and interim cost estimates for the Bruce A1 and 2 refurbishments.

Does OPG dispute any of these numbers?

MR. REINER: We have had an opportunity to look at this. We have not been able to validate every number in here, just because we didn't have the information readily available, but we had a lot of the information and it does align with documents that have been published in the past.

So there is no reason for us to dispute the numbers.

MR. ELSON: According to the report, it says as of September 2010 the actual costs of Ontario nuclear projects had been -- that had been completed to date have exceeded the original cost estimates by 2.5 times.

Does OPG agree or disagree with this statement?

MR. KEIZER: I am trying to recall, but didn't we visit this before on a previous motion, based upon an interrogatory request? I am just trying to refresh my memory with respect to going through each one of the -- the relevance of going through each number as to what had previously occurred on the Pickering project or some other unrelated project.

I guess I always struggle with the relevance of this question.

MS. HARE: Yes. This was discussed in an interrogatory, where it was requested, that the numbers are all confirmed. But I think, Mr. Elson, what you got from the witness was that they basically agree with the numbers that are here.

So what is the purpose of going through each one?

MR. ELSON: What I was referring to just now was the overall average of 2.5 times. So if they agree with that number as well, then I can move on.

MS. HARE: I don't actually see the 2.5. Where is that?

MR. ELSON: That is over the bar chart. It says -- over where it says "Ontario's history of nuclear cost overruns," there is a sentence that says:

"On average, the actual costs of the Ontario nuclear projects –-"

MS. HARE: I see that.

MR. ELSON: "-- completed to date have exceeded the original cost estimates by 2.5 times."

And if that is a number that is agreed with as well.

MR. KEIZER: But we had -- just now it's -- it's kind of with the assistance of Mr. Anderson, the fog is starting to clear.

But we had looked at this in the context of the previous interrogatory, which I think was much similar to the questions and the vein of questions that Mr. Elson is proceeding on, and I think the Board had indicated in Procedural Order No. 9 that the Board indicated that:

> "The Board's understanding is that the purpose of Environmental Defence's request is to review OPG's track record in terms of project managing cost overruns. It appears to the Board that the easier way to solicit this evidence without OPG verifying every source in the appendix" -- which is part of the footnotes that are attached to this, I believe –- "is to reframe the interrogatory: Does OPG have any basis/evidence to dispute the information contained in the Clean Air Alliance report, appendix A, page 17?"

And with respect to the cost overruns. And I think I can -- and the Board orders OPG to respond to this question prior to the commencement of the hearing. I haven't turned up the interrogatory response in itself.

MS. HARE: Were you not satisfied with the interrogatory response, Mr. Elson?

MR. ELSON: No, we were not. And that interrogatory response is actually at the following page, and that's Interrogatory Response No. 14.

But regardless, the question that I just asked, I think, was fairly straightforward. And if the answer is yes, then we can perhaps move on.

My recollection of the motion and actually looking at the motion, the Board did direct that further information be provided.

The response didn't address the cost overruns, even that OPG itself may or may not have incurred in its own past projects. The response said that it's OPG's opinion that in certain cases the report fails to provide certain critical information that properly sets the context of the cost increases.

It seems like Mr. Reiner is now saying that OPG is thinking that the numbers are accurate. So this is actually different from what the interrogatory response says, and which is why I would like to ask a couple of more questions about it.

MR. KEIZER: Well, the response isn't about the costs. It is a validation in respect to the references which are set out at appendix A at page 17 of the report.

I mean, my view would be to the extent that there is a series of questions here going through each and every number, why wouldn't we respect the Board's Procedural Order No. 9, and he can simply put the same question to the panel that was referenced in Procedural Order No. 9?

Which I think he, to some extent, already has initially, and they have answered it.

MR. ELSON: I believe I did put that question to the panel and I had a very simple follow-up question, which is whether the panel disputes the average of 2.5 times.

And I don't quite understand why we're debating this principle.

MS. HARE: I think, Mr. Reiner, you can probably answer that.

MR. REINER: Before I answer, maybe I can just go back to something I heard Mr. Elson say in regards to my previous answer.

My previous answer doesn't contradict what the interrogatory indicated. What I merely tried to identify is that this report, there are a number of references to documents in this report. The references that we had available to us, we validated, that indeed the numbers in the report matched the reference. And to that extent, these numbers are accurate.

I think what the report fails to do, however, is it takes a -- it takes a very defined set of projects and a set of numbers to draw a conclusion, and I would not necessarily agree with the conclusion that is drawn.

So I will give you an example. Pickering A, for example, there is a Pickering A unit 1 cost estimate that is cited. It is $213 million, and, yes, that can be found in the reference document.

However, when OPG approved the project to proceed with unit 1, the cost estimate that that approval was based on was a $900 million cost estimate.

So I think the problem with just saying yes to something like, does the math result in a conclusion that the projects exceeded original estimates by 2.5 times, it depends on what math you use. So I would disagree with the conclusion that is being drawn from this.

There are also some very large projects that have been executed on or under budget, and another example would be the Pickering unit 2-3 safe store project, and that is omitted from this report.

The other thing that I would just conclude is, it isn't a good practice to use history as the indicator for how the Darlington refurbishment project will get executed. So I think the approach for how we are managing that project needs to stand on the basis of the evidence we have provided, and I would not draw any conclusions around history of other projects to parallel that.

MS. HARE: Well, the Board, in making its finding, will give weight to the relevance of this information, but I think Mr. Elson is asking you -- basically your question is, is it true that they have been over-budget on all of the major projects. That is your question.

MR. ELSON: That's correct. And on average by about 2.5 times.

MR. REINER: So just on the example I cited on Pickering unit 1, I would have to disagree, because if you use the $900 million number, which was the estimate that the project was approved on, and the project came in at, I think we quoted in our interrogatory response, $1.016 billion -- it was actually 996 million. There was a $20 million cost that was incurred for some additional maintenance work.

If you were to factor that into the mathematics, that would change the mathematics.

MS. HARE: Sure.

MR. REINER: So I don't agree --

MS. HARE: Not to derail your cross, but then just explain to me, where did the 213 million come from? Mr. Reiner? Where did the 213 million come from?

MR. REINER: I think that is quoted in Mr. Elson's report --

MS. HARE: Yes, but --

MR. REINER: -- reference 55.

MS. HARE: -- that incorrect, that in 1999 that wasn't the estimate?

MR. REINER: That was a number that was put forth in -- at that date, but the project approval, the Board approval, to proceed with the project was based on a cost estimate of $900 million.

MS. HARE: Thank you.

MR. ELSON: I would like to actually take the witness to that reference. And to that end, if you could turn to page 7 of our document book, which is a report of the Pickering A review panel.

You will see on page 8 that this is a panel that was chaired by Jake Epp, and you would agree that, I assume, he's a very credible person and a former chair of OPG. Is that right, Mr. Reiner?

MR. REINER: Mr. Epp was the former chair of OPG, yes, that's correct.

MR. ELSON: And if you could turn to page 12 of the document book.

MR. REINER: If you could just help me for a second. Is that tab 3?

MR. ELSON: That is in tab 3, page 12, yes.

MR. REINER: Yes. Go ahead.

MR. ELSON: And I will read this to the second highlighted paragraph here. It says:

> "The August 1999 approval to proceed by the board of directors of the newly created OPG was based on a total project cost of 1.1 billion, with the following breakdown by unit. And it is $213 million for unit 1."

Do you agree with that paragraph there?

MR. REINER: That's what that paragraph says, yes.

MR. ELSON: Do you think that is an accurate number to reflect what the board approval was, the OPG board approval, in 1999?

MR. REINER: At that time that was the number, yes.

MR. ELSON: And you will see in the paragraph above that there is a discussion of an earlier approval in 1997, and that was based on a budget of $780 million for all four units. Is that number accurate?

MR. REINER: I believe that number is accurate, yes.

MR. ELSON: And again, the OCAA report is citing the 1999 cost estimate, not the much lower 1997 cost estimate. Is that right?

MR. REINER: Yes, it is.

MR. ELSON: Okay. Thank you. And if I could ask you

4 and Darlington original estimates came in over budget.

MR. ELSON: Thank you. And I can actually refer to the specific numbers, and I would ask the panel to confirm that Pickering Unit 4 was roughly 2.7 times over budget.

MR. REINER: Yes. Pickering 4 was about 2.7 times over budget.

But an important point to make here in relation to the Darlington refurbishment is that we recognize that there were problems with that project. And there were a significant amount of learnings that were extracted from that project, which weighed into the strategies and approach that we have developed for the Darlington refurbishment.

And we have used that approach in other cases. So if you look at -- if you look at a more recent track record on project performance, if you look at projects, for example -- I cited the Unit 2/3 safe store at Pickering. That is an example where a project, a significant project came in under budget.

There are other projects. The Upper Mattagami project is another case where we executed a very large project and it came in on budget. The Pickering A auxiliary power system project, another major project that was executed on budget.

So those learnings from Pickering have been applied, and they have been applied to the approach that we are implementing for Darlington.

MR. ELSON: The projects that you just cited, I understand those aren't refurbishment or new build projects; is that correct?

MR. REINER: One of them is the Upper Mattagami project; it is a redevelopment. So essentially --

MR. ELSON: I mean nuclear, I should clarify. They're not nuclear rebuilds or refurbishments?

MR. REINER: They are large nuclear projects. One is a safe store of Units 2 and 3. The other is building an auxiliary power system.

They're not refurbishments per se, but they are large nuclear projects that would have employed the same lessons learned to their methodology for managing the projects that we're applying to the Darlington refurbishment.

MR. ELSON: Moving on to Darlington, can you confirm that the cost overrun in comparison to 1975 was 4.5 times?

MR. REINER: Yes. Based on the numbers here, I can confirm that. And I think you have -- you have that cost breakdown in your package, tab 7 on page 19.

The interesting thing about that cost breakdown, you will notice that the interest charges are actually larger than the capital charges. So a significant portion of that cost overrun was the result of delays that were introduced to the project through a variety of reasons that manifested themselves throughout the construction time period.

MR. ELSON: In terms of the other three projects -- and this will be my last question on this area, I believe -- the three projects that you cited -- the safe store, the Upper Mattagami and the auxiliary power system -- which of those has the highest budget and what would that budget have been, very, very roughly?

MR. REINER: The Unit 2 safe store was about a $350 million project.

The Upper Mattagami project was close to that; it was about a $300 million project.

MR. ELSON: Thank you. I take it those cost overruns that were associated with the former Ontario Hydro and OPG's nuclear projects, those would have been passed on to Ontario ratepayers and/or the government of Ontario?

MR. REINER: This is an area that I am not really able to give you a precise answer on, because the regulatory process back in the Ontario Hydro days was quite different. So I couldn't give you a specific answer to that.

MR. ELSON: Perhaps Mr. Rose is more aware. I can't imagine where else those costs would have gone, but perhaps you could give an educated guess.

MR. ROSE: Well, I'm not going to guess something that I am unaware of, but my answer is the same as Mr. Reiner. I am not aware of the regulatory treatment at those points in time.

MR. ELSON: Okay. I would like to turn to the Long-Term Energy Plan, which is at tab 16 of our document book, which is page 51.

And on this page, you will see the seven principles that the nuclear refurbishment process will adhere to, and the first principle, as you can see, is:

"Minimize commercial risk on the part of ratepayers and government."

Do you see that there?

MR. REINER: Yes.

MR. ELSON: Now, the government is your sole shareholder, so any risk borne by OPG is risk borne by ratepayers or the government; is that right?

MR. REINER: Yes.

MR. ELSON: And that's different than, say, Bruce Power?

MR. REINER: Not necessarily, because I believe Bruce Power has a power purchase agreement with the government of Ontario, through the OPA.

MR. ELSON: I guess what I mean to say is that it is possible for Bruce Power itself to bear risk that doesn't fall on the government because it is a private company. That is my only...

MR. REINER: Well, the difference would be that Bruce Power in negotiating a power purchase agreement would factor a risk premium into their price of electricity, that based on whatever calculations they would do, that risk premium would factor in the potential of cost overruns or other uncertainties related to the project.

So essentially there is a payment that is made upfront for that risk, whether it materializes or not. And that would be a key difference.

MR. ELSON: So if the risk materializes, then it is a hit that Bruce Power takes, but it has been paid to assume that risk?

rate regulation that we're governed under.

I think an important distinction to actually see what the value of that is, is a comparison of the price of power from Ontario Power Generation versus Bruce Power.

MR. ELSON: The fourth principle is to:

"Hold the private sector operator accountable to the nuclear refurbishment schedule and price."

And presumably that applies to Bruce.

And the fifth principle is to:

"Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price."

You see that there, the fifth principle?

MR. REINER: Yes.

MR. ELSON: And I take this to mean that OPG's contractors can't be allowed to pass on their cost overruns to OPG. Would you agree with that synopsis?

MR. REINER: It would depend what the cost overrun is tied to. So one element of a refurbishment, given the nature of what we're dealing with in a nuclear reactor, there are areas of the plant that are not accessible when there is fuel in the reactor. So there are some unforeseens regarding the scopes of work that are going to be encountered.

It would be unreasonable to expect the contractor to understand what those unforeseens might be, so that wouldn't be a risk that would get passed on to a contractor.

That would get dealt with through a scope assessment that OPG would execute, and if it is work that is deemed as required as part of the refurbishment, then the contractor would get paid for executing that work.

MR. ELSON: Why would it be reasonable to make OPG liable for those unforeseens, but not have the contractors be liable for those unforeseens?

MR. REINER: Well, OPG is actually in the best position to assess what that unforeseen might entail. OPG is the owner of the asset. We've got the technical expertise to assess what the impacts of the condition of specific components might be on the future reliable operation of the plant.

And that would then manifest itself in a requirement that would then get translated to work that a contractor executes.

MR. ELSON: Now, the question that I am getting at is what this fifth principle means in your mind or in OPG's mind. It says that OPG has to hold its contractors to their price, and I am getting from your answer that you don't think this means that you have to require them to actually meet their price. If they have a cost overrun, it is fine if you absorb it.

MR. REINER: I was just giving you an example of where there may be cases where cost overruns are the result of a legitimate scope increase. However, if you look at the evidence that we submitted on our contracting strategies, you will see that there are significant schedule and cost incentives and disincentives in the contracts which are

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2013-0321**	
VOLUME:	**14**	
DATE:	**July 16, 2014**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Christine Long	**Member**
	Allison Duff	**Member**

from what I'm seeing.

MR. MILLAR: J14.2.

UNDERTAKING NO. J14.2: TO FILL OUT THE TABLE AT PAGE 2 OF THE ENVIRONMENTAL DEFENCE DOCUMENT BOOK.

MR. ELSON: Thank you. Moving on; would you agree, Mr. Reiner or Mr. Rose, that it's –– or would you be aware that the OPA has signed many electricity supply contracts with individuals, with First Nation communities, with municipal electric utilities and private sector corporations, for renewable and natural gas-fired generation projects?

MR. REINER: I am aware that -- I am aware that the OPA has done that. I couldn't give you any details around that, because that is not -- that doesn't involve our refurbishment project.

MR. ELSON: Your refurbishment, no. Based on your general understanding of those contracts, would you agree that none of them allow renewable and gas-fired generators to pass on their capital cost overruns to electricity consumers and/or taxpayers?

MR. REINER: I wouldn't be able to answer that question, because I don't have any knowledge of those contracts or what the terms are or what the cost provisions are or incentives or disincentives. So I'm not in a position to be able to answer that.

MR. ELSON: So that isn't something you would like at, for example, would be a comparison between the kind of risk that you would have in your contracts as compared to other move on.

MR. REINER: What we have looked at as a model is fixed-pricing a contract -- which is, I think, what you're getting at -- and how does that compare to a target price.

In our view, the premiums associated with fixed-pricing a contract would be significant, and wouldn't necessarily give us the outcome that we're looking for.

And there are some good test cases in the nuclear industry to look at, Point Lepreau being a good example.

MR. ELSON: Is $12.9 billion OPG's most up-to-date, high-confidence estimate of the cost of the DRP, including interest and escalation?

MR. ROSE: That is correct.

MS. HARE: Microphone on, please.

[Witness panel confers]

MR. ROSE: Yes. The 12.9 billion is our latest estimate.

MR. ELSON: And according to your response to ED Interrogatory No. 5, I believe you're planning to debt-finance 53 percent of the cost of this project; is that right?

MR. KEIZER: Sorry, is that part of your document book, or are you...

MR. ELSON: It is. It is at tab 11, page 27. And that's actually page 28 of the interrogatory, under (d).

MR. ROSE: That is the debt-equity ratio that the corporation currently uses. And we anticipate that the project will be funded under the same scenario that the risk assumed potentially by the OEFC and whether that is an issue for the long-term energy -- for the LTEP principles.

So perhaps I will try to ask one more question, which would be that, you know, my understanding is the OEFC would be assuming some sort of risk if it is back-stopping this debt obligation. Would you agree with that?

MR. REINER: If OEFC is back-stopping the debt, I mean, and they are financing it, there would be some assumption of risk, yes.

MR. ELSON: Okay. Thank you. I think that is sufficient.

MS. HARE: Okay. Thank you.

MR. ELSON: I will move on to issues 4.7 to 4.10, which relate to the reasonableness of the Darlington capital expenditures and financial commitments, and I am going to start by asking the panel some questions about the expected LUEC of Darlington and then compare those with other sources of power.

Now, as you have noted, the high-confidence estimate of the total cost of the Darlington rebuild is roughly $13 billion. Is that right? 12.9, to be specific?

MR. ROSE: That is correct. 12.9, including interest and future escalation; that's correct.

MR. ELSON: And according to your response to ED Interrogatory 5, which you don't need to turn up if you remember, this corresponds to an estimated LUEC of 8.3 cents per kilowatt-hour? That is at page 28 of the document book if you need to refresh your memory.

according to this report.

MR. ELSON: Thank you. This is my question, and I am going to request an undertaking with a number of parts, so I will try to state it clearly.

Would you be able to recalculate the LUEC of the Darlington rebuild project with the following assumptions: A), its total capital cost is 12.9 billion; B), 30 percent debt financing, C), 70 percent equity financing at a rate of 18 percent; and D), three alternate scenarios about the annual capacity utilization rate; namely 65, 82, and 88 percent. Could you provide that undertaking, that calculation?

MS. HARE: I'm sure the math can be done, but is there value in this?

MR. KEIZER: No, I don't think there is value in it. First of all, Bruce is not a regulated entity. So the cost of capital for private investors in a non-regulated entity and the threshold or hurdle rates that they would expect would be higher than the cost of return on equity that a regulated entity has, plus the fact that the debt levels are different for regulated entity because of risk and exposure that ratepayers bear.

So I think this is a fictitious capital structure that wouldn't be applicable in this scenario.

MS. HARE: Mr. Elson, why do you need this?

MR. ELSON: The purpose of gathering this number is because it is our understanding that this project is being compared to private projects and also would, you know, aim

MR. ELSON: Thank you. Now, OPG's Pickering nuclear station will go out of service by 2020 at the latest; is that right?

MR. REINER: That's the current end-of-life based on what we know about fuel channel life. That is the expected end-of-commercial-operation date.

MR. ELSON: And if the government of Ontario ultimately doesn't approve the Darlington rebuild, then Darlington would go out of service in 2020 as well; is that correct?

MR. REINER: It would be around -- again, based on what we know to date about fuel channel life, it would be in the early 2020s, based upon how the units came in-service.

MR. ELSON: So roughly 2020, 2021? Roughly speaking?

MR. REINER: 2020, 2021.

MR. ELSON: Okay. So if that were to occur, OPG would cease being a producer of nuclear electricity in roughly six years; is that correct?

MR. REINER: If that were to occur, that's correct.

MR. ELSON: And so persuading the government of Ontario to approve this project would be essential for the continuation of OPG as a provider of nuclear electricity generation.

MR. REINER: Well, I think this project has been identified in the Long-Term Energy Plan as being a critical component of Ontario supply mix as a result of fuel diversity, cost competitiveness, so I don't know that it is a matter of persuasion. It's been identified as being part and parcel of the Long-Term Energy Plan.

MR. ELSON: Approximately how many or what percent of OPG's staff are on the nuclear side? Just very roughly.

MR. REINER: Now, that would have been in evidence in the nuclear panel. I would have to -- I would have to see what that number is. I don't know.

MR. ELSON: Would you have a rough estimate off the top of your head and we can check afterwards? It is not necessary. It is a significant number, I understand.

MR. REINER: It would be. It's probably about 60 percent of the employee population.

MR. ELSON: Thank you. And in light of that, and in light of the other facts we just discussed, would you agree that OPG or its nuclear staff would have an incentive to underestimate or at least minimize the probability that the Darlington rebuild project would go overbudget?

MR. REINER: There is no incentive whatsoever to understate that. Our analysis is based on the way this project is being established, and I think as Mr. Rose earlier indicated, we are working towards a release quality estimate in 2015. That's based upon some very detailed knowledge about what the actual work is going to be that we're going to execute, having engineering completed, having long lead materials ordered, having all of the contracts in place. There's no incentive here to understate the cost.

MR. ELSON: So even though that would mean -- or even though it is possible that Darlington -- sorry, I should rephrase that.

Even though it is possible that OPG would cease being a producer of electricity in roughly six years and that that would impact 60 percent of its staff, very roughly, in your mind there's no incentive there. You deny that there is any incentive to...

MR. REINER: That did not weigh into any of the analysis that was done in our business case.

MR. ELSON: Now, I'm not saying that it did. I'm just asking whether you acknowledge or you believe that there is an incentive there. I believe the answer is no.

MS. HARE: He answered your question.

MR. ELSON: Thank you.

MR. REINER: There is no incentive there to falsely state costs as a result of a potential closure of the nuclear business, none whatsoever.

MR. ELSON: I am going to ask a number of questions that relate to what you have and haven't done, and if you haven't done it, I would appreciate if you could just state that you haven't done it, rather than state that -- what you also have done instead, because we know what is on the evidence, and it would just help us move forward a bit more quickly. Of course, you can add any context that is necessary, but some of these questions should be fairly simple, and we can move through them.

Have you done a comparison between the expected LUEC of Darlington and the cost of energy conservation?

MR. REINER: No, we have not.

MR. ELSON: And what about a comparison with combined heat and power plants?

MR. REINER: No.

MR. ELSON: And a comparison with hydro power imports from Quebec?

MR. REINER: We have not done a comparison of hydro power imports from Quebec, but we have -- the question about hydro power imports from Quebec has come up, and we have addressed some of the issues associated with that.

MR. ELSON: Where would that be found?

MR. REINER: That came up in the technical conference, in the first technical conference following RD2-2-1 evidence.

MR. ELSON: Would you ever use those sorts of cost comparisons with alternatives to help OPG set targets or objectives for the Darlington refurbishment?

MR. REINER: It isn't --those cost comparisons is not what we would use to set objectives.

MR. ELSON: Do you think it is incumbent on OPG to build Darlington at a cost that is more cost-effective than alternative sources of power, such as combined heat and power plants, hydro power, et cetera?

MR. REINER: I mean, from an OPG perspective, we need to go back to what the Long-Term Energy Plan calls for and what we have been asked by our shareholder to do.

MR. ELSON: Regardless of whether -- I'm not suggesting that you go against the Long-Term Energy Plan.

MS. HARE: I don't think the panel needs to answer that question.

MR. ELSON: Okay. I will move on.

In order to refurbish Darlington, the units need to be shut down for about three years each while the refurbishment occurs; is that right?

MR. ROSE: That is correct. That is a current estimate of the schedule for refurbishing each unit at Darlington.

MR. ELSON: And OPG plans to shut down Unit 2 in October of 2016 and restart it in December 2019; is that right?

MR. ROSE: We plan to start it -- shut it down in October 2016 and restart it approximately 36 months later.

MR. ELSON: And while that is happening, there would be other sources of supply to the grid? Replacement power, you could say?

MR. REINER: Of course. I mean, there would need to be a replacement for that unit being offline, if the province continues to provide a reliable supply of electricity, which I am assuming would be the case.

MR. ELSON: Sure. And do you have an estimate of the cost of that replacement power per kilowatt-hour while Units 1 and 2 are out of service?

MR. REINER: I do not.

MR. ELSON: Would that power largely be coming from the Pickering continued operations?

The reason I ask that question is that without the continued operation of Pickering, Units 5 to 8 would be shut down in 2014 to 2016. So in a sense, is Pickering continued operations, in part, needed to replace the foregone power because Darlington is shutting down early in the refurbishment?

MR. REINER: I don't believe Pickering continued operations is needed for that precise reason. Pickering continued operations makes economic sense, and the basis for operating that station to the end of its pressure tube life, it is just good business.

There isn't -- there isn't a requirement for Pickering to continue to operate for the refurbishment to start. Pickering would clearly be producing electricity during that time period where the first unit is shut down.

MR. ELSON: I guess Pickering would be part of the source of replacement power for Darlington while it is shut down?

MR. REINER: It would still be available to the grid in order to provide power, yes.

MR. ELSON: Thank you.

My final questions -- and I am actually coming to a close after this -- relate to the contracting strategies.

And we touched on this briefly, but I understand that OPG decided against refurbishing Darlington on a turn-key basis, but it considered that option; correct?

MR. REINER: That was considered, yes.

MR. ELSON: And how much would it have cost to do the refurbishment on a turn-key basis?

MR. REINER: We actually did not enter into negotiations with any contractors to get to a precise price of that. And so I couldn't -- I couldn't give you an estimate.

What we had looked at as we were developing our strategies is options, options for fixed pricing, for target pricing. And what the analysis pointed to is that a fixed price would result in a fairly significant risk premium that a target price would not.

So it is the analysis on the strategy that led us towards target pricing. We did not actually go out and get bids to see what the cost would be.

MR. ELSON: Would you be able to go back and look at your notes and put your heads together to come up with even a very rough ballpark figure of what a turn-key kind of process would cost?

Right now, we understand your cost is $13 billion. Would it be in the range of 20 billion, 30 billion, 50 billion? Just a very broad-strokes estimate of a turn-key basis approach?

MR. KEIZER: Madam Chair, we're not building a backyard shed here, where we can -- it's a very complex project, which is multiple units over a number of years. And the evidence is all clearly indicating that.

He has also indicated they haven't explored it, so I think to go back now and eyeball it and say: Hmm, I think it is somewhere in the range -- I don't know how that can be reliable.

MR. KEIZER: That's correct, Madam Chair.

MS. HARE: Mr. Elson?

MR. ELSON: Thank you, Madam Chair.

So maybe I should focus on the re-tube and feeder replacement --

MS. HARE: Can I just interrupt here for a second? How much longer do you have? I am not going to cut you off because we certainly chewed into your time with our deliberations, but it is eleven o'clock, so it would be a suitable time for a break unless you tell me you only have, you know, five minutes left.

MR. ELSON: I think I have more than five minutes, but it should be under 15.

MS. HARE: Well, then why don't we take a break now until 11:20?

MR. ELSON: Thank you.

--- Recess taken at 11:03 a.m.

--- On resuming at 11:24 a.m.

MS. HARE: Please be seated.

Mr. Elson, are you ready to continue?

MR. ELSON: Yes, thank you, Madam Chair.

Again, I am going to just focus on the -- I am going to just focus on the re-tube and feeder replacement component with respect to the contracting strategies, because it's my understanding that this component is over 50 percent of the overall cost of the refurbishment; is that correct?

MR. ROSE: It's over 50 percent of the overall cost of the work portion, the contracted portion of the project.

MR. ELSON: Thank you.

And Ontario Power Generation considered seeking fixed-price lump-sum turn-key agreement for the re-tube and feeder replacement work package in order to achieve greater price certainty and risk transfer, but that model was deemed to be unavailable at a reasonable cost. Is that correct?

MR. REINER: We did assess that strategy, and submitted in our evidence are also the reports from Concentric. We had asked Concentric to review those strategies and to assess our proposed path forward to target-price elements of this.

There are fixed-price elements in the re-tube and feeder replacement job, so we did not discount that approach. We applied the fixed price where it made sense and target price where it made sense.

And if I could maybe ask Mr. Reed to just provide a comment on that assessment.

MR. REED: Yes. And this goes to the question of what's in evidence on this point. Specifically, Exhibit D2-2-1, attachment 7-1 is our report on both the overall Darlington refurbishment program as well as the R&FR project.

And we did review the company's consideration of lump-sum turn-key arrangements, fixed-price arrangements, different contractor models, in terms of EPC and self-perform and other structures.

which is a pretty limited subset.

MS. LONG: Thank you. Sorry, Mr. Elson.

MS. HARE: Mr. Elson, please continue, and don't worry about your time allotment.

MR. ELSON: Thank you.

MS. HARE: This is not your fault.

MR. ELSON: Thank you, Madam Chair.

I think I have to follow up on those -- that brief discussion.

Mr. Reed, were you involved in discussions, you yourself involved in discussions, with SNC-Lavalin about the possibility of a lump-sum contract?

MR. REED: Not directly. My information is based upon our discussions with the company and representatives that were in those meetings, on documents that went into and came out of those meetings, and on public statements made by SNC representatives.

MR. ELSON: So when you say statements like "we didn't get into that" or "we didn't look at that," you're not talking about you and your firm? You're talking about OPG; is that correct?

MR. REED: You would have to be specific as to what reference you are making there to we.

MR. ELSON: I believe you made a comment about assessing whether lump sum would cost 20 billion or 30 billion, and you said: We didn't get into that discussion.

Do you mean your firm or OPG didn't get into that discussion?

MR. REED: I meant our firm, Concentric, did not get into trying to determine at what price the risk premium was going to reach a point of indifference. And we did not recommend to OPG that they play that game with the vendors.

MR. ELSON: Mr. Reiner, because I assume you would have been closer to this, those first-hand discussions, did you actually ask SNC-Lavalin to do the project on a turn-key basis?

MR. REINER: The way the procurement process was executed is we started out with an expression of interest to the vendor community at large, and that expression of interest resulted in a variety of responses.

In -- first off, who the players were that were interested in potentially taking on this work, and what sort of a form of contractual arrangement that would entail.

That expression of interest then led to a development of a contracting strategy. And through that process of developing the contracting strategy, we fix-priced elements of this contract and we target-priced other elements of the contract.

So it does two things.

We -- and in the case of the re-tube and feeder replacement project, I think it is sort of a -- it tends to be a hybrid. We fix-priced the areas where we saw that the risks were clearly in the vendor space to manage. We target-priced the elements based on, as Mr. Reed described, where the risks laid with OPG and it was OPG's to manage.

So that's ultimately where we landed through this process.

MR. ELSON: So I am getting from that answer that you didn't actually ask them for a lump sum quote?

MR. REINER: No. We did not ask them for a lump sum quote to fix-price the entire job.

MR. ELSON: Thank you.

MR. REED: Mr. Elson, if I could add a point on that, which I think is documented in the evidence here, the company did specifically ask for an approach to contracting that was short of LSTK, a form of contracting called JV or joint venture contracting, in which a joint venture would be established that would be owned by OPG, by the multiple contractors performing their work. And collectively, the profit or loss of that JV would determine the profit or loss of the contractors.

That was specifically proposed to all of the bidders, and that is obviously a level of risk that is far, far less than LSTK or lump sum fixed-price contracting.

None of the bidders, not one, agreed that it would submit a bid -- at any price -- under a JV structure.

JV structures actually have a lot more success in other industries, because they -- again, they are short of a fixed-price arrangement, but if the bidders weren't prepared to submit a bid at all under a JV structure, it certainly says to me that they wouldn't be comfortable going beyond that. And that --

MS. HARE: Mr. Reed, just to understand, you weren't

MR. ELSON: I am asking Mr. Reiner to confirm that this is his understanding.

MR. REINER: That's correct.

MR. ELSON: Thank you.

And instead, OPG obviously settled on a different strategy, and under that strategy OPG reimburses actual costs, but the contractor suffers a penalty if it goes under budget, but OPG will still pay the actual costs; is that a rough summary of what the contracting strategy is for the RFR work component?

MR. REINER: Under the target cost model, in general, cost is paid for, and incentives and disincentives are structured around a target cost.

Now, costs aren't always paid for. There are circumstances where the quality of work, which is risk that clearly lies in the contractor space, if there is a quality of work issue that requires rework to be done, that is the contractor's cost. So that is 100 percent in the contractor's space.

There are also warranty provisions, that if the work is faulty and the equipment fails, rectification is 100 percent in the contractor's space.

But assuming the job progresses without quality issues and without any warranty issues, then the cost, the cost is paid and the contractor is incentivized to achieve the target cost and target schedule because they would essentially be paying OPG back profits and overheads associated with that cost.

MR. ROSE: Can I also clarify, when we talk about costs that are being paid we're talking about the direct costs related to performing the work, the scope of work for this R&FR project.

That is the target price. The target price is set on that direct work.

The profit and overhead, referred to as a fixed fee, is set aside. That is paid under the assumption that the project progresses against -- in accordance with the target price.

If the vendor goes over the target price, the profit and the overhead are no longer paid, and we start to recover those overages from the profit and overhead. So the costs are actually deducted from previously paid profit and overhead.

MR. ELSON: So let me just try to focus on the contractor costs, setting aside the fixed fee. We understand that the profit or the fee is based on -- they're basically incentive payments.

MR. ROSE: It is not just profit, though. It is overhead as well.

MR. ELSON: The profit and overhead. Focussing on the costs of the contractor, under this target strategy you have basically full reimbursement of, let's say, reasonably incurred costs, so as to exclude, you know, quality issues.

Would that be a good summary?

MR. ROSE: Yes, for direct work, except for rework or warranty work.

MR. ELSON: Thank you. I understand that the lion's share of the RFR work is done at that target, with that target price model.

MR. ROSE: The execution phase, the actual refurbishment within the units during the refurbishment outage, are done under the target price contract model, which is a large percentage of the overall R&FR contract. That is correct.

MR. ELSON: And can you -- what, roughly, percent would that be? 75, 80, 90?

MR. ROSE: About 70 to 80 percent.

MR. ELSON: Thank you. So 70 to 80 percent is the target pricing model that we were just discussing.

Now, under this RFR strategy, I understand that contractors would play an active role, but OPG would retain the ultimate control and risk; is that fair to say?

MR. REINER: Well, OPG inevitably carries the risk associated with schedule delays. It is a risk that can't be shed.

If there is a schedule impact that doesn't allow the unit to be returned to service when expected, that risk lies with OPG, and it manifests itself in a number of ways.

There's the obvious reputational risk associated with an overrun on the project, the asset is not available to produce electricity and generate revenue, so that is a risk that ultimately will remain with OPG.

MR. ELSON: I guess my question was a bit more broad than schedule risk. Perhaps I could just refer you to page 5 of our supplementary document book. There's a discussion of the re-tube and feeder replacement strategy, and it says that OPG retains the ultimate control and risk. Is that your evidence?

MR. REINER: Yes.

MR. ELSON: Thank you.

MR. REINER: And that is in reference to what I just described. I mean, ultimately what that tries to characterize in those few words is that there is an element of risk here that OPG will bear, that it is not able to shed.

MR. ELSON: Now, another way to describe it would be to say there's shared incentives, with OPG bearing the primary risk. Would that be a fair way to characterize it?

MR. REINER: Well, I mean, that's what the words indicate here.

This is why we structured the project in a way that has OPG manage the work and have visibility into schedules and into the specific execution of work that the contractor is performing.

And the key here is, if you were in an incident that is similar to what the Point Lepreau station encountered, there was a technical issue that was known, and the contractor made a decision to proceed with -- understanding that there is a technical issue.

They made an assumption that they would be able to put forth a compelling case to the regulator that that technical issue won't cause a problem with operation of the strategies for the new build as a model or as an indication for what the government of Ontario is looking for in terms of cost containment.

MR. REINER: We did not specifically look at what new build was doing, again, because we did not have access to that. But the model, being a fixed-price, turn-key approach, is something that was assessed in our approach.

And we had discounted it because we did not see that as a reasonable approach. The premiums were quite significant, and ultimately we could find ourselves in a situation that Point Lepreau was in, where decisions are being made about the assets that would ultimately then manifest themselves as a significant risk to the owner.

And we did not see that as -- a key learning for us in establishing this project was not to repeat that same mistake.

MR. ELSON: I guess part of your job is to understand what the long-term energy principles mean. You're trying to figure out what the government of Ontario is asking you to do.

As part of that process, I take it you didn't look at the requirements of the new build project as a template or comparison; is that correct?

MR. REINER: We did not use the new build discussion as a template. That's correct.

MR. ELSON: Thank you. I have no further questions.

MS. HARE: Thank you, Mr. Elson.

So Ms. Feinstein, on behalf of the Lake Ontario

Assessment of Commercial Strategies Developed for the Overall Darlington Refurbishment Project and the Retube & Feeder Replacement Work Package

Prepared for Ontario Power Generation

September 2013

service projects: 1) Pickering A, Units 1 and 4 in Pickering, Ontario ("Pickering A"); 2) Bruce A, Units 1-4 in Inverhuron, Ontario ("Bruce A"); and 3) Point Lepreau in Point Lepreau, New Brunswick ("Point Lepreau"). These three projects represent the most recent attempts to successfully plan, design, and execute significant refurbishment or repair work on Canadian CANDU reactors, and each project utilized a different commercial strategy. Each project encountered challenges to the successful completion of the refurbishment work. We also reviewed limited information from a refurbishment project at the Wolsong Generating Station in South Korea ("Wolsong"). The Wolsong project was completed in July 2011 and represents the most successful (*e.g.,* cost and schedule performance) CANDU refurbishment project yet. Although Wolsong employed a commercial strategy similar to that employed by NB Power at Point Lepreau, we believe certain differences in the labor and nuclear services markets account for at least a portion of the success at Wolsong. Ontario Power Generation examined, and continues to examine, these prior projects, and plans to incorporate the lessons learned from these projects in the planning, definition, and execution activities of the Project.

- Third, the Project is confronted generally with two types of risk: 1) extrinsic risk (*i.e.*, risks that are outside of Ontario Power Generation's control); and 2) intrinsic risk (*i.e.,* risks that are within Ontario Power Generation's control) that largely relate to the technical and commercial aspects of the project. With regard to extrinsic risk, the scale and duration of the Project make it vulnerable to changes in the economic, financial, political, regulatory and social assumptions that support the Project. While certain commercial strategies can result in vendor agreements that mitigate a portion of extrinsic risks, no economically viable commercial strategy can be expected to eliminate the bulk of those risks. In response, Ontario Power Generation is taking steps to mitigate the extrinsic risks through the use of a "gated" review and approval process. This gated review and approval process will phase Ontario Power Generation's commitment to the Project into discrete periods and costs and will allow Ontario Power Generation to evaluate the ongoing feasibility of the Project at each interval. As it relates to the intrinsic risk, Ontario Power Generation is undertaking several activities to mitigate these risks. These activities include, but are not limited to, completing the Project's design in advance of construction, evaluating long lead procurement items, constructing full scale reactor mock-ups to test the specialized tooling that must be designed and fabricated for the project, and evaluating the operational experiences of other recent refurbishment projects. When combined with Ontario Power Generation's gated approval process, these steps will lower the Project's intrinsic risk as it proceeds into each new phase of the Project, although, inevitably, certain intrinsic risks will remain for the Project and all similar projects.

B. OVERALL PROJECT COMMERCIAL STRATEGY

The overall commercial strategy selected by the Project team is the multi-prime contractor model. Under this model, Ontario Power Generation will retain project management responsibility and design authority for the Project. To execute the work, Ontario Power Generation will retain multiple contractors for discrete portions of the Project work known as work packages. Consistent with this approach, Ontario Power experts. Those vendors will assist Ontario Power Generation with the oversight function by providing relevant expertise developed from other major projects.

Consistent with Ontario Power Generation's gated review and approval process for proceeding with each phase of the Project, Concentric believes all of the agreements that result from this strategy should include sufficient off-ramps and hold points at which continuing with the Project will be fully reconsidered. These milestones include, but are not limited to:

- Issuance of a release quality estimate,
- The start of each unit outage, and
- Instances when prime vendor performance is substantially below expectations.

D. ALTERNATIVES CONSIDERED

Prior to selecting its multi-prime contractor model strategy, Ontario Power Generation considered several alternative commercial strategies. Those alternative strategies included partnering, a lump sum turnkey agreement, and a project management organization structure. Ontario Power Generation rejected each of those strategies for the reasons described below.

Beginning in December 2009, the Project team was focused on a partnering concept that would seek to utilize a single agreement with multiple vendors, possibly combined in a joint venture, for the purpose of designing and executing the work packages. That agreement would have tied the vendors' financial performance to the overall success of the entire project rather than just a vendor's performance on its scope of work. The partnering concept was initially favored because, in its optimal form, the concept would better align the interests of all involved vendors and potentially promote a cooperative work environment. This concept was advocated in the 1990s by several industry participants, but experience with the partnering model has shown that alignment is difficult to achieve, and vendors largely rejected this model due to their inability to "control their own fate." That is to say, vendors have expressed a concern that their financial performance is tied to actions that are beyond their own control (*i.e.,* the performance of another vendor on the project). As a result, projects that utilized the partnering strategy often fostered less cooperative project environments where vendors were engaged in disputes with each other over the cause of delays or cost over-runs.

The Darlington Refurbishment Project team also considered a fixed price, lump sum, turnkey model similar to that employed by NB Power at Point Lepreau. At a basic level, this strategy would have turned over the entire Project to a single vendor and required the vendor to complete the entire scope of work and return an operable unit back to Ontario Power Generation. This strategy, when coupled with a fixed or target price, is expected to provide greater price certainty and greater risk transfer. However, the fixed-price, lump sum, turnkey strategy would have largely eliminated Ontario Power Generation's control over the final design, pace, and management of the Project. In addition, recent experience with this strategy has demonstrated that although the model proposes to transfer significant risk to a vendor, such risk transfer is largely unachievable in a nuclear safety environment due to exemptions for excused events and force majeure, the owner's liability for nuclear safety, and a lack of complete, detailed designs. As a result, the price premium paid to transfer risk is usually not commensurate with actual risk transferred to a vendor. At Point Lepreau, the fixed price, lump sum, turnkey strategy has largely protected NB Power from cost overruns, but has provided limited protection from schedule slippage and the extensive cost of replacement power that resulted. Lastly, a fixed-price, lump sum, turnkey agreement for a nuclear power project of this magnitude is not likely to be commercially feasible in the current market. SNC Lavalin, the acquirer of the commercial reactor division assets of Point Lepreau's contractor (AECL), has indicated that it is unwilling to accept the same level of risk that AECL accepted in past contracts.[10]

Finally, Ontario Power Generation considered retaining a project management organization similar to the strategy initially employed by Bruce Power for the refurbishment of Bruce A. Pursuant to this model, Ontario Power Generation would have retained a qualified firm experienced in the management of megaprojects similar to this Project. The project management organization would have been responsible for planning the Project, negotiating agreements with prime contractors for the execution of the Project work, and managing the various work packages. This strategy would allow Ontario Power Generation to rely on an experienced project management organization that is expected to utilize industry best practices to plan and implement the Project. However, a project management organization strategy often suffers from a lack of alignment between the project management organization, the owner, and the prime contractors responsible for completing the work. This is particularly true in a tight market for such services, as is the case in Canada's market for nuclear services, because the project management organization may also be responsible for a portion of the execution phase work. Consequently, other vendors would have been expected to reject a project management organization due to concerns over future disputes between the vendors and the project management organization. Even if the model was accepted by capable vendors, Ontario Power Generation could expect to pay a substantial premium for the risk of project management organization and contractor disputes. Bruce Power has encountered difficulties with the project management organization strategy related to conflicts between the project management organization and its vendors and the project management organization's alignment with Bruce Power's interests. As a result, Bruce Power largely abandoned the project management organization strategy after approximately two years and moved to a multi-prime strategy.

As discussed above, Concentric agrees with Ontario Power Generation that it was reasonable and prudent to select the multi-prime model under the current market circumstances and to reject the alternatives considered by the Company.

VII. RETUBE AND FEEDER REPLACEMENT

A. OVERVIEW

The Retube & Feeder Replacement work package is expected to determine the Project's critical path[11] and includes the removal and replacement of each reactor's 480 pressure tubes and calandria tubes and the removal and replacement of the existing feeders. Because of the critical nature of this work, Ontario Power Generation has focused significant resources on selecting a reasonable commercial strategy and securing a vendor to perform the Retube & Feeder Replacement work prior to advancing the other work packages. Just

[10] In June 30, 2011 article in *Canadian Business*, SNC Lavalin Executive Vice President Patrick Lamore was quoted as saying, "We don't want to go backwards but obviously we would only bid the projects that have acceptable terms and conditions to our risk profile and where we make the margins that are expected for a commercial business to survive."

[11] At a basic level, the critical path of a project is made up of those activities that must be completed on time in order for the project to proceed to each new phase of the project on schedule.

as Ontario Power Generation selected from available contracting strategies at the Project level, it must do the same for the selection of a vendor for the Retube & Feeder Replacement work package.

B. Ontario Power Generation's Retube & Feeder Replacement Commercial Strategy

The commercial strategy selected by Ontario Power Generation for the Retube & Feeder Replacement agreement is a hybrid EPC agreement that combines elements of fixed/firm pricing for known or highly definable tasks and a target price for the remaining scope of the Retube & Feeder Replacement work package where less detailed information is available.[12] Additionally, Ontario Power Generation's commercial strategy has incorporated a phased project schedule that will divide the work into a definition phase, an execution phase and a commissioning phase. During the definition phase, Ontario Power Generation and its selected vendor will complete the detailed design of the Project, procure long lead materials, fabricate long lead components and tools, test the specialized tooling and complete final planning activities. At the conclusion of the definition phase work, Ontario Power Generation and its selected vendor will complete a cost estimating process to determine the "execution phase target price." The execution phase target price will create an estimate of the total cost to complete the execution phase work with upper and lower cost sharing bands. Within these cost sharing bands, Ontario Power Generation and the selected vendor will jointly share in cost over-runs or under-runs. Outside of these cost sharing bands, the Retube & Feeder Replacement agreement reverts to a cost reimbursable agreement, excluding vendor profit and overhead. Ontario Power Generation will, likewise, include financial incentives for early completion of each unit outage and financial penalties for failure to complete unit outages within the agreed upon schedule. If Ontario Power Generation and the selected vendor are unable to agree on an execution phase target price and schedule, Ontario Power Generation will retain the tooling in order to conduct the execution phase work with an alternate contractor.

Concentric's review of the Project's Retube & Feeder Replacement contracting strategy has highlighted the following advantages and disadvantages of this approach:

- Advantages: Flexibility to adapt to the project's evolving project scope; incentives are created to limit cost increases and schedule delays; control over the design of station modifications.
- Disadvantages: Creates substantial oversight responsibilities; once the cost for each unit exceeds the target price and caps for each unit, the contract is essentially a cost reimbursable (excluding vendor overhead and profit) agreement with a more limited risk transfer relative to a fixed price agreement.

C. Basis for Selection

The current hybrid EPC strategy for the Retube & Feeder Replacement work package was selected in order to fulfill several objectives. Specifically, Ontario Power Generation reviewed prior operating experience from similar refurbishment projects and determined the need to retain overall control and responsibility for project management and design authority. The operational experience reviewed included specific lessons learned

[12] This EPC agreement differs from the Engineering, Procurement and Construction agreement employed by NB Power at Point Lepreau in that the agreement relates to only a single work package and includes a hybrid pricing structure.

ED Interrogatory #011

Ref: Ex. D2-2-1, Attachment 5, Updated 2014-02-06, page 2; and Ex. D2-2-1, pages 15 – 22.

Issue Number: 4.12
Issue: Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

Interrogatory

a) Please provide a break-out of management's "high confidence" estimate of the total cost of the DRP, including capitalized interest, escalation and all other costs, in 2013$ and 2014$, according to the following categories: (i) RFR; (ii) Fuel Handling; (iii) Turbine-Generator; (iv) Steam Generators; and (v) Balance of Plant.

b) Please provide a breakout of the: (i) RFR; (ii) Fuel Handling; (iii) Turbine- Generator; (iv) Steam Generators; and (v) Balance of Plan costs according to:
(A) contractor costs; and (B) non-contractor costs.

c) Please state the total cost of the DRP to OPG in 2013$ and 2014$ assuming the RFR, Fuel Handling, Turbine Generator; Steam Generators and Balance of Plan costs exceed budget by: (i) 50%; (ii) 100%; (iii) 150%; (iv) 200%; and (v) 250%. In each scenario, please also state: (i) the percentage of the contractors' cost overruns that are passed on to OPG; and (ii) the DRP's LUEC in 2013$ and 2014$.

Response

a) & b) The table below provides the requested break-out based on the amounts included in Ex. D2-2-1, Attachment 5. Interest and escalation are planned at the Program level and not at the individual project level and therefore have not been provided.

$M		2013$	2014$
RFR	OPG Project Management	[redacted]	
	Contractor Cost		
	Contingency		
Fuel Handling	OPG Project Management		
	Contractor Cost		
	Contingency		
Steam Generators	OPG Project Management		
	Contractor Cost		
	Contingency		
Turbine Generator	OPG Project Management		
	Contractor Cost		
	Contingency		
Balance of Plant	OPG Project Management		
	Contractor Cost		
	Contingency		

Notes:
1. 2013$ estimate based on Ex. D2-2-1, Attachment 5
2. 2014$ assumed 2% inflation

c) The DRP contracts are structured in a manner that allocates risk to the entity that is best able to manage that risk. For example, the Retube and Feeder Replacement (“R&FR”) tooling contract is fixed price, therefore, regardless of cost growth, OPG is protected. The R&FR Execution work is target price with incentives for the contractor to lower costs. In a situation where cost growth is significant, the contractor looses a portion of their fee as well as overheads for additional costs incurred beyond the target price.

The table below provides the “high confidence” DRP cost under a range of contractor cost over-run scenarios including the % of costs passed on to OPG and the impact on the DRP LUEC for each scenario.

	Total DRP cost (P90)		% of Cost Passed to OPG		Impact on LUEC (P90) (Increase)	
	2013$ (Billion)	2014$B (Billion)	2013$	2014$	2013 (cents)	2014 (cents)
50%	10.0	10.2	81%	81%	0.0	0.0
100%	10.2	10.4	75%	75%	0.1	0.1
150%	11.1	11.3	72%	72%	0.3	0.3
200%	12.1	12.3	69%	69%	0.6	0.6
250%	13.1	13.3	68%	68%	0.9	1.0

Assumptions

1. Each project bundle has a variety of contracting strategies including Fixed Price, Target Price, Cost Plus, and Time and Material; the calculation of the "% of Costs Passed onto OPG" is based on these contract strategies. This analysis assumes that the % of cost growth is spread evenly across all elements of the contract including fixed price, materials, and target price.
2. For each scenario, contingency, as reported in part a) and b) is reduced prior to incurring cost growth to the project; i.e. a 50% cost increase to the project decreases contingency and remains within the $10 Billion high confidence estimate.
3. OPG has maintained additional contingency and management reserve, i.e. only contingency distributed to the projects, in part a) and b) has been reduced due to cost overruns. Contingency and management reserve remains for other risks.
4. 2014$ assumed 2% inflation

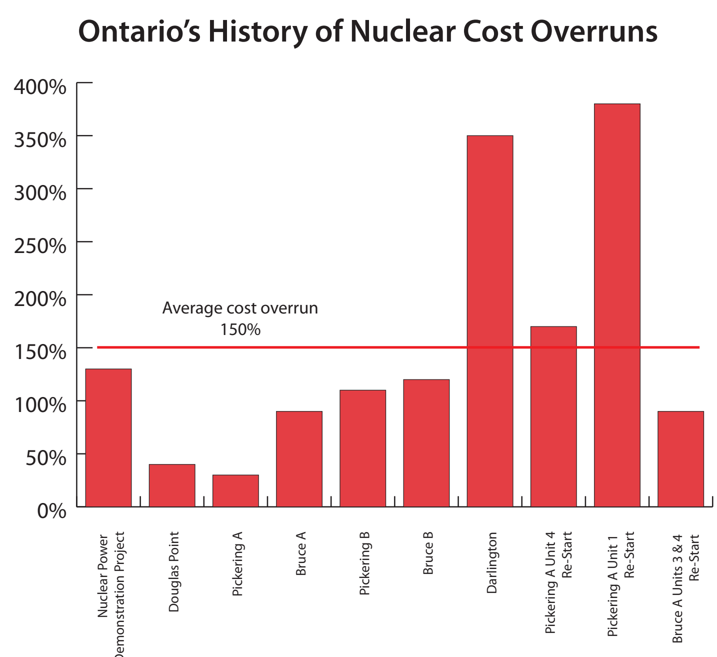
Appendix A: Ontario's History of Nuclear Cost Overruns and Ontario Hydro's Stranded Nuclear Debt

Ontario's History of Nuclear Cost Overruns

Every nuclear project in Ontario's history has gone over budget.

- The original cost estimate for the 20 megawatt (MW) Nuclear Power Demonstration Project on the Ottawa River was $14.5 million.[39] The actual cost was 2.3 times higher at $33 million.[40]
- The original cost estimate for the 200 MW Douglas Point Nuclear Power Station on Lake Huron was $60 million.[41] The actual cost was 1.4 times higher at $85 million.[42]
- In 1967 Ontario Hydro estimated that the 2,160 MW Pickering A Nuclear Generating Station would cost $527.65 million.[43] The actual cost was 1.3 times higher at $700 million.[44]
- In 1969 Ontario Hydro estimated that the 3,200 MW Bruce A Nuclear Generating Station would cost $944 million.[45] The actual cost was 1.9 times higher at $1.8 billion.[46]
- In 1975 Ontario Hydro estimated that the 2,160 MW Pickering B Nuclear Generating Station would cost $1.8 billion.[47] The actual cost was 2.1 times higher at $3.8 billion.[48]
- In 1975 Ontario Hydro estimated that the cost of the 3,200 MW Bruce B Nuclear Generating Station would be $2.7 billion.[49] The actual cost was 2.2 times higher at $5.9 billion.[50]
- In 1975 Ontario Hydro estimated that the cost of the 3,400 MW Darlington Nuclear Generating Station would be $3.2 billion.[51] The actual cost was 4.5 times higher at $14.319 billion.[52]
- In 1999 Ontario Power Generation (OPG) estimated that the total cost of returning the shutdown Pickering A Unit 4 to service would be $457 million.[53] The actual cost was 2.7 times higher at $1.25 billion.[54]
- In 1999 OPG estimated that the total cost of returning the shutdown Pickering A Unit 1 to service would be $213 million.[55] The actual cost was 4.8 times higher at $1.016 billion.[56] Nevertheless, a February 2010 OPG news release asserted that the project was completed "on budget".[57]
- Bruce Power estimated that the total cost of returning the shutdown Bruce A Units 3 and 4 to service would be $375 million. The actual cost was 1.9 times higher at $725 million.[58]
- In 2005 the Ontario Power Authority signed a contract with Bruce Power for the return to service of the shutdown Bruce A Units 1 and 2. In 2005 the estimated capital cost was $2.75 billion. The units have still not been returned to service, but in February 2010 TransCanada Corp. (a major shareholder of Bruce Power) estimated that the project will cost $3.8 billion.[59]

On average, the actual costs of the Ontario nuclear projects that have been completed to-date have exceeded their original cost estimates by 2.5 times.



Fool me once, shame on you. Fool me twice, shame on me. Fool me 11 times...

Ontario Hydro's Stranded Nuclear Debt

In 1999, as a result of the cost overruns and the poor performance of its nuclear reactors, Ontario Hydro was broken up into five companies. All of its generation assets were transferred to Ontario Power Generation (OPG). In order to keep OPG solvent, $19.4 billion of Ontario Hydro's debt or unfunded liabilities associated with electricity generation facilities was transferred to the Ontario Electricity Financial Corporation (an agency of the Government of Ontario) as "stranded debt" or "unfunded liability".[60]

The Ontario Electricity Financial Corporation (OEFC) collects revenues from the following sources to help pay off the nuclear stranded debt.

- A debt retirement charge of 0.7 cents per kWh which is levied on all Ontario electricity consumers.
- All of the provincial income tax payments from OPG, Hydro One and Ontario's municipal electric utilities (e.g., Toronto Hydro).
- All of the dividend payments from OPG and Hydro One to their sole shareholder, the Government of Ontario.

In 2009, the sum of the above-noted nuclear debt retirement payments was $1.8 billion.[61] This is equivalent to an annual nuclear debt retirement charge of $137.73 per person in Ontario or $551 for a family of four.[62]

The defunct Ontario Hydro's nuclear debt costs Ontario's consumers and taxpayers $1.8 billion per year.

In 2001 the OEFC forecast that the nuclear debt would be fully paid off "in the years ranging from 2010 to 2017".[63] However, as of 2009, the debt has only been reduced by $3.2 billion to $16.2 billion.[64] The OEFC is now forecasting that the debt will be eliminated between 2014 and 2018.[65]

Endnotes

1 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 6.

2 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 11.

3 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 014.

4 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 10.

5 Ontario Energy Board Docket No. EB-2010-0008, Exhibit JT1.2.

6 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Pages 4 & 5.

7 Ontario Energy Board Docket No. EB-2010-0008, Undertaking JT1.3.

8 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 002.

9 Ontario Ministry of Energy, Science and Technology, *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario*, (November 1997), page 7. The Ontario nuclear industry often claims higher average capacity utilization rates by ignoring the performance of reactors that are temporarily or permanently and pre-maturely shutdown.

10 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

11 OPG Review Committee, *Transforming Ontario's Power Generation Company*, (March 15, 2004), Page 50.

12 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

13 Emails from Carrie Reid and Rebecca Short, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, July 21, 2010 and September 14, 2010.

14 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 004.

15 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 6, Schedule 002 and Tab 10, Schedule 002.

16 Letter from CIBC World Markets Inc. to James Gillis, Ontario Deputy Minister of Energy, October 17, 2005.

17 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 006.

18 According to OPG, assuming 70% equity financing and a required equity rate of return of 18%, the Darlington Re-Build will produce electricity at a total cost of 10 to 14 cents per kWh (assuming an 82% capacity utilization rate) or 12 to 18 cents per kWh (assuming a 64% capacity utilization rate). Furthermore, according to OPG, the Darlington Re-Build's non-capital costs (i.e., operating, maintenance, administration and fuel costs) are 3.9 to 5.2 cents per kWh. All costs are in 2009$. We have increased OPG's estimated capital costs per kWh by a factor of 2.5 to calculate the impact of a 150% capital cost overrun on the Darlington Re-Build's total cost of power. Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedules 003 and 006.

19 Ontario Clean Air Alliance, *Conservation vs. Electricity Supply: A summary of the Ontario Power Authority's procurement efforts*, (July 19, 2010).

20 Ontario Power Authority, *Industrial Accelerator Program: Program Rules Version 2.0*, (June 24, 2010), pages 13, 14 & 15.

21 Ontario Power Authority, *Supply Mix Analysis Report*, Volume 2, (December 2005), page 210; and *Integrated Power System Plan*, Exhibit G, Tab2, Schedule 1, page 7.

22 Assuming energy efficiencies of 80 to 90% and an average annual capacity utilization rate of 90%. Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 90.

23 Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 21, page 1.

24 *Integrated Power System Plan*, Exhibit L, Tab 8, Schedule 7: Thomas R. Casten, Recycled Energy Development LLC, *The Role of Recycled Energy and Combined Heat and Power (CHP) in Ontario's Electricity Future*, page 3.

25 Catherine Strickland & John Nyboer, MK Jaccard and Associates, *Cogeneration Potential in Canada: Phase 2*, (April 2002), page 30.

26 Hagler Bailly Canada, *Potential for Cogeneration in Ontario: Final Report*, (August 2000), page 25.

27 Ontario Power Generation, *Sustainable Development Report 2009*, page 46.

28 Ontario Energy Board Docket No. EB-2008-0272, Exhibit I, Tab 5, Schedule 6.

29 Hydro Quebec, *Annual Report 2009: Shaping The Future*, page 53.

30 Ontario Power Authority, *A Progress Report On Electricity Supply: First Quarter 2010*, pages 6, 24 & 25.

31 Steve Erwin, "Bruce nuclear cost overruns will fall in taxpayers' laps: critics", *Brockville Recorder and Times*, October 18, 2005.

32 Tyler Hamilton, "Reactor repairs confirmed over budget", *Toronto Star*, April 18, 2008.

33 *Second Amending Agreement to the Bruce Power Refurbishment Implementation Agreement Between Bruce Power L.P. and Bruce Power A L.P. and Ontario Power Authority*, July 6, 2009. Available online at: www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=891.

34 Ontario Ministry of Energy, *News Release*, "Ontario Takes Next Step To Ensure Clean, Affordable And Reliable Energy Supply For Generations To Come", (March 7, 2008).

35 According to the Government's news release, "The competitive process will help to ensure the greatest amount of cost certainty, lowest possible price and a fair approach to risk sharing." See Infrastructure Ontario, *Backgrounder*, "Nuclear Procurement Project Phase 2", (June 16, 2008).

36 Shawn McCarthy & Karen Howlett, “Ontario’s move puts AECL’s future in doubt”, *Globe and Mail*, (June 30, 2009).

37 Tyler Hamilton, “Nuclear bid rejected for 26 billion reasons: Ontario ditched plan for new reactors over high price tag that would wipe out 20-year budget”, *Toronto Star*, (July 14, 2009).

38 Romina Maurino, “Province puts nuke plans on hold”, *Toronto Sun*, (June 30, 2009); and Susan Riley, “Nuclear summer”, *Ottawa Citizen*, (July 31, 2009).

39 G. Bruce Doern, *Government Intervention in the Canadian Nuclear Industry*, (The Institute for Research on Public Policy, 1980), page 104.

40 The Hydro-Electric Power Commission of Ontario, *Annual Report 1962*, page 60.

41 *Government Intervention in the Canadian Nuclear Industry*, page 107.

42 Paul McKay, *Electric Empire: The Inside Story of Ontario Hydro*, (Between The Lines, 1983), page 59.

43 The Hydro-Electric Power Commission of Ontario, *Annual Report 1967*, page 57.

44 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

45 The Hydro-Electric Power Commission of Ontario, *Annual Report 1969*, page 34.

46 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

47 Ontario Hydro, *Annual Report 1975*, page 4.

48 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

49 Ontario Hydro, *Annual Report 1975*, page 4.

50 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

51 Ontario Hydro, *Annual Report 1975*, page 4.

52 Letter from Rosemary C. Watson, Freedom of Information Coordinator, Ontario Power Generation to Ravi Mark Singh, Ontario Clean Air Alliance, April 27, 2004.

53 *Report of the Pickering “A” Review Panel*, (December 2003), page 4.

54 *Report of the Pickering “A” Review Panel*, (December 2003), page 4.

55 *Report of the Pickering “A” Review Panel*, (December 2003), page 3.

56 OPG, *News from Ontario Power Generation,* “Ontario Power Generation Reports 2005 Third Quarter Financial Results”, (November 11, 2005).

57 OPG, *News Release*, “OPG Moves to Planning Phase of Darlington Refurbishment”, (February 16, 2010).

58 Letter to James Gillis, Ontario Deputy Minister of Energy from CIBC World Markets Inc., October 17, 2005.

59 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 2, Schedule 015.

60 Ontario Electricity Financial Corporation, *Annual Report: April 1, 1999 to March 31, 2000*, page 8.

61 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 12.

62 Ontario’s population in 2009 was 13,069,200.

63 Ontario Electricity Financial Corporation, *Annual Report 2001*, page 29.

64 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 11.

65 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 20.

66. According to the NB Power Group’s *2007/08 Annual Report*, total construction costs, excluding replacement fuel and purchased power costs, would be approximately $1 billion (see page 20). According to recent reports, the project is approximately $1 billion over budget. See Chris Morris, “Leaders spar over Lepreau”, *Telegraph-Journal*, (August 23, 2010).

UNDERTAKING J14.2

Undertaking

To fill out the table at page 2 of the Environmental Defence document book.

(Provide the additional table that was provided in the ED supplementary compendium at pages 1-4.)

Response

OPG has provided the results of pro-rating OPG's high confidence estimate by 50%, 100%, 150%, 200%, and 250% and have noted the amounts, in each scenario, that are passed along to OPG from the contractor. The response has been provided in $2013 as this is the basis of OPG's detailed information as provided in D2-2-1 and D2-2-2 and for purposes of expediency in thisresponse.

OPG has responded to this as requested, however, we do not believe that the information provides a reasonable basis to assess the potential future costs that may be expended by OPG in executing the Darlington Refurbishment Project.

OPG, and the construction industry as a whole, have learned significantly in the experiences of past large complex projects and have embraced a robust front end planning process. The front end planning process, based on industry best practices from the Construction Industry Institute (CII) and the Association for the Advancement of Cost Engineering (AACEi) provides OPG with a proven standard for developing confidence in its estimate, and at the time of Release Quality Estimate (RQE) in October 2015, OPG will have progressively developed a high degree of certainty for each of the contractors' estimates that form the basis for the target price.

Specifically, each contractors' target price will be based on the completion of detailed engineering and comprehensive work packages which fully describe the methods in how the work will be performed. The Re-tube and Feeder Replacement project represents over 60% of the Darlington Refurbishment Projects critical path of the project. All of the tools will be time-tested in the full-scale mock-up prior to setting the target price. This front end planning will be used to finalize the target price.

This is not to suggest that there will be no risks associated with the execution of the project. In OPG's approach, the risks get allocated to the entity best able to manage those risks.

The target price contracts are structured in a way to incent the vendors to achieve the target price and schedule, and, have disincentives for failure to meet this including reductions [redacted] of the contractors profit and overhead costs.

If the contractor exceeds the target price, OPG will continue to pay the direct costs, i.e. actual costs for trades and project management labour, however, without markups including profit or overhead. OPG's contracts have open book provision which allows OPG to audit the direct costs to ensure that no profit centres are embedded in the rates; payments are based on negotiated union agreements and actual costs paid for project management.

OPG is the General Contractor and will play an active role in monitoring the work. OPG would intervene and take appropriate actions to mitigate the circumstances as contemplated in this undertaking. The contractors are responsible and have a significant incentive to mitigate and recover delays and overruns. There are off ramps in the contracts that allow OPG to terminate contracts without penalty in situations where performance was not meeting OPG requirements.

In order to respond to this undertaking, we have included a number of conditions that we do not believe are reasonable.

- OPG was asked to artificially pro-rate contingency which is not appropriate. Contingency would be used to offset risks and cost growth in executing the work program and should be reduced to zero. OPG has provided a scenario which removes all contingency.

- OPG has artificially pro-rated all of its owner's costs, including project management. This is also not reasonable as the owner's costs would not grow in relation to any perceived growth in contractor costs.

OPG has provided the information as requested, however, it is for the reasons noted above that we do not deem this to be a reasonable representation of any likely outcome of the Darlington Refurbishment Project.

EB-2013-0321 - Cost Overrun Scenarios - Breakdown by Category

J14.2 a (with contingency growth)

Major Category	Category / Contract Type	Base Case $2013	50% Cost Growth		100% Cost Growth		150% Cost Growth		200% Cost Growth		250% Cost Growth	
			Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG
RFR	OPG Project Management	690	1,035	1,035	1,380	1,380	1,725	1,725	2,070	2,070	2,415	2,415
	Contractor Cost	[redacted]										
	Tooling (Fixed Price)											
	Mockup (Fixed Price)											
	Owner Specified Materials (Cost Plus)											
	Definition Phase (Target Price/ Fixed Fee)											
	Execution Phase (Target Price/ Fixed Fee)											
	Contingency											
	Total											
Fuel Handling	OPG Project Management	83	125	125	166	166	208	208	249	249	291	291
	Contractor Cost	[redacted]										
	Defueling - Eng Services (Fixed/Firm Price)											
	Defueling - Eng Services (Misc Reimbursables)											
	Fuel Handling (Fixed Price)											
	Contingency											
	Total											
Steam Generators	OPG Project Management	63	95	95	126	126	158	158	189	189	221	221
	Contractor Cost	[redacted]										
	Fixed Price											
	Target Price/ Fixed Fee											
	EPC Other											
	Contingency											
	Total											
Turbine Generators	OPG Project Management	195	293	293	390	390	488	488	585	585	683	683
	Contractor Cost	[redacted]										
	Eng Serv & Equip Supply (Fixed Price)											
	Eng Serv & Equip Supply (Target Price)											
	Installation - Defn Phase (Target Price/ Fixed Fee)											
	Installation - Exec. Phase (Target Price/ Fixed Fee)											
	EPC											
	Contingency											
	Total											
Balance of Plant	OPG Project Management	216	324	324	432	432	540	540	648	648	756	756
	Contractor Cost	[redacted]										
	EPC & T&M											
	Contingency											
	Total											
Other Costs	Islanding											
	System Shutdown											
	Operations & Maintence Support	863	1,295	1,295	1,726	1,726	2,158	2,158	2,589	2,589	3,021	3,021
	Facilities & Infrastructure	820	1,230	1,230	1,640	1,640	2,050	2,050	2,460	2,460	2,870	2,870
	Waste Management	10	15	15	20	20	25	25	30	30	35	35
	New Fuel	132	198	198	264	264	330	330	396	396	462	462
	Insurance	114	171	171	228	228	285	285	342	342	399	399
	Regulatory, i.e. ISR, EA, IIP	80	120	120	160	160	200	200	240	240	280	280
	Licensing (CNSC Fees)	73	110	110	146	146	183	183	219	219	256	256
	Contingency	[redacted]										
	Retube Waste Containers (Provision)	220	330	330	440	440	550	550	660	660	770	770
	Management Reserve	568	852	852	1,136	1,136	1,420	1,420	1,704	1,704	1,988	1,988
	Total	[redacted]										
Subtotal		10,000	15,000	14,010	20,000	18,308	25,000	22,606	30,000	26,904	35,000	31,203
Interest & Escalation		2,900	4,350	4,063	5,800	5,309	7,250	6,556	8,700	7,802	10,150	9,048
Total		12,900	19,349	18,073	25,800	23,617	32,250	29,162	38,700	34,706	45,150	40,251
LUEC For Each Cost Scenario (cents)		8.3		9.9		11.6		13.2		14.9		16.6

Assumptions:
Cost growth is applied to all costs ~~except contingency.~~
Contingency amounts are decreased by the cost overruns and are accounted for in the total costs for each scenario.
Current cost estimate is OPG's current "high confidence" estimate.
Project components costs (RFR, Fuel Handling etc.) include all costs, including OPG management costs, contractor costs, and other costs.
Total includes all project component costs and intestest and escalation.
LUEC includes all costs, including interest, escalation, and fixed corporate overheads for pensions and other post employment benefits.
Percent cost growth is applied to all costs and is spread evenly across all costs.

OPG Assumptions:
Interest & escalation prorated
An increase of Project cost of $1B will result in a LUEC increase of approximately $0.003 (0.3 cents).

EB-2013-0321 - Cost Overrun Scenarios - Breakdown by Category

J14.2 b (contingency removed to offset cost growth)

Major Category	Category / Contract Type	Base Case $2013	50% Cost Growth		100% Cost Growth		150% Cost Growth		200% Cost Growth		250% Cost Growth	
			Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG	Gross costs	Costs passed to OPG
RFR	OPG Project Management	690	1,035	1,035	1,380	1,380	1,725	1,725	2,070	2,070	2,415	2,415
	Contractor Cost	[redacted]										
	Tooling (Fixed Price)	[redacted]										
	Mockup (Fixed Price)	[redacted]										
	Owner Specified Materials (Cost Plus)	[redacted]										
	Definition Phase (Target Price/ Fixed Fee)	[redacted]										
	Execution Phase (Target Price/ Fixed Fee)	[redacted]										
	Contingency	[redacted]										
	Total	[redacted]										
Fuel Handling	OPG Project Management	83	125	125	166	166	208	208	249	249	291	291
	Contractor Cost	[redacted]										
	Defueling - Eng Services (Fixed/Firm Price)	[redacted]										
	Defueling - Eng Services (Misc Reimbursables)	[redacted]										
	Fuel Handling (Fixed Price)	[redacted]										
	Contingency	[redacted]										
	Total	[redacted]										
Steam Generators	OPG Project Management	63	95	95	126	126	158	158	189	189	221	221
	Contractor Cost	[redacted]										
	Fixed Price	[redacted]										
	Target Price/ Fixed Fee	[redacted]										
	EPC Other	[redacted]										
	Contingency	[redacted]										
	Total	[redacted]										
Turbine Generators	OPG Project Management	195	293	293	390	390	488	488	585	585	683	683
	Contractor Cost	[redacted]										
	Eng Serv & Equip Supply (Fixed Price)	[redacted]										
	Eng Serv & Equip Supply (Target Price)	[redacted]										
	Installation - Defn Phase (Target Price/ Fixed Fee)	[redacted]										
	Installation - Exec. Phase (Target Price/ Fixed Fee)	[redacted]										
	EPC	[redacted]										
	Contingency	[redacted]										
	Total	[redacted]										
Balance of Plant	OPG Project Management	216	324	324	432	432	540	540	648	648	756	756
	Contractor Cost	[redacted]										
	EPC & T&M	[redacted]										
	Contingency	[redacted]										
	Total	[redacted]										
Other Costs	Islanding	[redacted]										
	System Shutdown	[redacted]										
	Operations & Maintence Support	863	1,295	1,295	1,726	1,726	2,158	2,158	2,589	2,589	3,021	3,021
	Facilities & Infrastructure	820	1,230	1,230	1,640	1,640	2,050	2,050	2,460	2,460	2,870	2,870
	Waste Management	10	15	15	20	20	25	25	30	30	35	35
	New Fuel	132	198	198	264	264	330	330	396	396	462	462
	Insurance	114	171	171	228	228	285	285	342	342	399	399
	Regulatory, i.e. ISR, EA, IIP	80	120	120	160	160	200	200	240	240	280	280
	Licensing (CNSC Fees)	73	110	110	146	146	183	183	219	219	256	256
	Contingency	[redacted]										
	Retube Waste Containers (Provision)	220	330	330	440	440	550	550	660	660	770	770
	Management Reserve	568										
	Total	[redacted]										
Subtotal		10,000	[redacted]	10,104	[redacted]	13,100	[redacted]	16,096	[redacted]	19,092	[redacted]	22,089
Interest & Escalation		2,900	[redacted]	2,930	[redacted]	3,799	[redacted]	4,668	[redacted]	5,537	[redacted]	6,405
Total		12,900	[redacted]	13,034	[redacted]	16,899	[redacted]	20,764	[redacted]	24,629	[redacted]	28,494
LUEC For Each Cost Scenario (cents)		8.3		8.3		9.5		10.7		11.9		13.0

Assumptions:
Cost growth is applied to all costs except contingency.
Contingency amounts are decreased by the cost overruns and are accounted for in the total costs for each scenario.
Current cost estimate is OPG's current "high confidence" estimate.
Project components costs (RFR, Fuel Handling etc.) include all costs, including OPG management costs, contractor costs, and other costs.
Total includes all project component costs and intestest and escalation.
LUEC includes all costs, including interest, escalation, and fixed corporate overheads for pensions and other post employment benefits.
Percent cost growth is applied to all costs and is spread evenly across all costs.

OPG Assumptions:
Interest & escalation prorated
An increase of Project cost of $1B will result in a LUEC increase of approximately $0.003 (0.3 cents).

ONTARIO ENERGY BOARD

FILE NO.: **EB-2013-0321**

VOLUME: **Technical Conference**

DATE: **July 8, 2014**

that. However, we are going to look at that facility in particular, as we would with any facility, what is its contribution to refurbishment, what is its contribution to continued operations.

And, I mean, I will leave it up to the finance folks and our rates folks on where those costs would go. I don't think it would impact the in-service additions at all, but we will -- we will go through an exercise to apportion the cost to the right place.

MR. SHEPHERD: So then I don't understand. The refurbishment wouldn't be in service now. It's refurbishments in service in 2018 or something; right?

MR. REINER: But that facility is a used and useful facility. It will have heavy water in it, the heavy water will be flowing to the tritium removal facility, the water will be de-tritiated while we are refurbishing the unit.

So, I mean, this gets into a question of the accounting treatments around assets in service. I mean, we would follow whatever the required practices are.

MR. SHEPHERD: How far along are you in this parsing of the refurbishment versus non-refurbishment scope?

MR. REINER: For this particular facility we have not -- we have not done that yet. We have not looked at that yet.

MR. SHEPHERD: You have done it for some of the other components of the campus plan?

MR. REINER: There are some projects that we are executing that I listed in the 19 that are for operations purposes and for continued operations, like the operations support building.

Now, we are -- it is a refurbishment cost, and it is a refurbishment cost because those facilities wouldn't be required if we didn't refurbish the plant. But there aren't any facilities like this one that have kind of that dual purpose.

MR. SHEPHERD: Well, if I just go down this list in table 1 of the, what, nine named projects plus -- no, sorry, seven named projects plus three groups, right? Is that right? Can you tell me whether you have done an analysis of refurbishment versus non-refurbishment use for each of these, or which ones have you done such an analysis?

MR. REINER: So the -- on this list, the Darlington OSB is a facility that's required for operations purposes. It's not a refurbishment facility. The rest of these facilities --

MR. SHEPHERD: Why is it called refurbishment? Help me understand.

MR. REINER: Because the project entails the refurbishment of a building. A building is being refurbished. The refurbishment project is -- relates to the Darlington units. So it's just a title. It's a project title.

MR. SHEPHERD: Okay.

MR. REINER: So it is part and parcel of the overall refurbishment program, but it is not a facility that is required by the refurbishment project.

MR. SHEPHERD: All right.

MR. REINER: So --

MR. SHEPHERD: Is it an existing building or is it a replacement building?

MR. REINER: It's an existing building. That building has issues with mould that has to be remediated. It's also got issues associated with fire suppression, so it needs to be upgraded to current fire codes.

MR. SHEPHERD: Why is it part of the Darlington refurbishment project at all then?

MR. REINER: Well, if we were running the station to the end of life, we would probably find ways to avoid making the investment in that facility. That facility will be there for the next 25 to 30 years of operation of the station.

MR. SHEPHERD: I see. Okay.

So then D2O storage you have already explained, right? That that -- how that's used for the two. You haven't done a formal analysis of that; right?

MR. REINER: We haven't done an analysis of how the costs apportion between continued operations and refurbishment.

MR. SHEPHERD: Now, you had that coming in service during the test period in full, as I understand it, but now it's coming in service outside of the test period, but you are still closing some stuff to rate base. I don't understand why that would be. I mean, it's a storage

MR. MILLAR: Good afternoon. Why don't we get started? From the time estimates we have before us, it looks like we have a little bit less than two hours of non-confidential materials, so we should at minimum be able to get through that today.

Mr. Elson, are you ready to proceed?

QUESTIONS BY MR. ELSON:

MR. ELSON: Yes, thank you.

I perhaps should introduce myself to the panel. My name is Kent Elson and I represent Environmental Defence. I hope to be very brief today. I have two quick --

MR. KEIZER: Sorry, we had one undertaking response we were going to give, I think.

MR. REINER: Yes. Just a follow-up from this morning, my apologies. So Undertaking JT3.6, the question was asked who the firm is that is doing the root cause analysis, and it is a company. The initials are AEMRI, and that stands for the Adult Education and Management Research Institute.

MR. ELSON: Thank you. My first line of questions is just at a very, very basic level about the campus plan project. I understand from your evidence that the variance is going to turn out to be between 200 and $300 million; is that right?

MR. REINER: Yes. That's correct.

MR. ELSON: I heard this morning a number of 260; is that your best estimate so far?

MR. ROSE: That is our estimate today, as we updated our evidence found in D2-2-2.

MR. ELSON: And that's -- is that test period or overall?

MR. ROSE: That is overall. The majority of that cost variance is within the test period -- actually, let me correct that, because of the D2O, in-service now is actually going into 2016, the majority of it is not in the test period.

MR. ELSON: And what was the original estimate for the campus plan project? So 260 is getting added on to what?

MR. REINER: I think this level of cost breakdown was redacted in our business case submissions, so this would have to go to the in camera discussion, but we can provide that.

MR. ELSON: Can you provide a reference and I'll just look it up? That would be the best way to do it.

MR. ROSE: In fact, our estimates are in the business case under D2-2-1, attachment 5. There is actually a table that shows a line item of the facility and infrastructure projects, and provides this estimate that -- as we provided in 2009 and the latest estimate. On top of that, we would add the 2- to 300 or current point of 260 to that number.

MR. ELSON: I believe in the Modus report there is a number listed in the unredacted version of 552 million; is that the number?

MR. ROSE: That is in the right range, yes.

MR. ELSON: That's in the right range?

So what we are talking about is -- page 16.

MR. KEIZER: Sorry, of which report, Mr. Elson?

MS. GIRVAN: The June 26th report on page 16 has the original estimate of -- the 4C estimate of 552 million and the current forecast of 824 million.

MR. ELSON: So are those the current numbers that you are working with?

MR. ROSE: These are Modus's numbers that they had provided at that point in time. They are reasonably close to ours, but our -- I can't attest to the fact that they are exactly the same as ours.

MR. ELSON: Well, let's just say it's approximately a 50 percent increase; is that right?

MR. ROSE: It's in the right range. Correct.

MR. ELSON: So who will bear the cost of that cost overrun, OPG customers or the shareholder?

MR. REINER: That cost is still within the total refurbishment project cost that we have declared, so even with this cost increase, we are still within that $10 billion total cost of refurbishment.

MR. ELSON: That wasn't quite my question. Holding everything else constant, what we have now is an increase of approximately $260 million. Who would bear those costs, the consumers or the shareholder?

MR. REINER: We would expect to recover all of the costs associated with refurbishment, including this cost. And I think as part of that, we just need to, again, characterize the costs appropriately. I just want to, for a second -- you know, it's a cost overrun in the sense that

UNDERTAKING JT3.5

Undertaking

To provide an updated list of projects classified as used and useful now rather than part of the Darlington Refurbishment Project

Response

Part A

Please refer to the attached tables:

Attachment A – The attached table includes a detailed listing of Projects included in D2-2-2, Table 1 and includes annual In Service and OM&A expenditures. The amounts included in D2-2-2 Table 1 are based on the forecasted amounts as of May 2014 and may not align with the latest OPG approved Business Case.

Attachment B – The attached table includes detailed descriptions of the used and useful partial in service additions represented by the in-service amounts found in Attachment A.

Part B

The following summarizes the basis for used and useful of all of the assets to be placed in-service in the rate period per Exhibit D2-2-2.

Darlington Operations Support Building (OSB) Refurbishment will be used and useful in providing office space for operations support staff, technical services, security systems, IT, telephone network hub etc. to the station when it is placed in service to electricity ratepayers in 2015.

D2O (Heavy Water) Storage Facility will be used and useful for storing heavy water and for managing heavy water drums when it is placed in service as the first unit is dewatered prior to refurbishment. Partial in-service amounts will be immediately used and useful as these services are required for ongoing TRF and station operations.

Darlington (DN) Auxiliary Heating System will be used and useful in providing reliable back-up steam to the station when it is placed in service in 2015. Back up steam is needed to prevent potential equipment damage due to freezing when all four Darlington units are shut down.

Water and Sewer became used and useful as each phase was placed in service in 2012, 2013, and 2014 in providing a reliable domestic and fire water supply to the station and replacing the existing sewage services to the station.

Electrical Power Distribution System will be used and useful in providing reliable electrical power to the existing and new buildings at the station as each phase is placed in service in 2013 and 2014. It will replace the existing system which has degraded over time.

Darlington Energy Complex became used and useful when it was placed in service in

2013 in providing space for training including reactor mock-up, warehouse space for tooling and materials, and office space. Additional in-service amounts in 2013 and 2014 include the surrounding site servicing including roads and street-scaping.

Re-tube and Feeder Replacement (RFR) Island Support Annex will become used and useful when it was placed in service in 2016 and used by Refurbishment staff to execute the Refurbishment project and in support of Darlington online and outage maintenance activities.

Other Campus Plan Projects will become used and useful once placed in-service and used to support station projects and outages, as well as refurbishment work. The GM facility is currently being used by Station staff due to the fact that the Operations Support Building is being refurbished as well as nuclear project staff working on Refurbishment and non-refurbishment projects. Other facilities, including Salt Shed, parking improvements, and contractor facility will support station needs, including outages and Nuclear Portfolio projects.

Safety Improvement Opportunities are projects that OPG must complete prior to the first unit refurbishment as part of the Environmental Assessment for the Refurbishment and continued operations of Darlington and will become used and useful by the station once placed in-service as these are safety enhancements to the existing station. These projects include:

1. **Third Emergency Power Generator** will be used and useful in meeting an EA commitment to CNSC by providing improved availability and reliability of the Emergency Power System at the station when it is placed in service in 2015. It will be able to withstand a higher level seismic event than the Design Basis Earthquake.
2. **Containment Filtered Venting System** will be used and useful once placed in service in 2015. Partial in-service amounts of $2M will be used and useful immediately as it allows for a controlled, filtered release of airborne activity to the environment from Containment to prevent failure from over-pressurization during severe accidents.
3. **Powerhouse Steam Venting System** will be used and useful in meeting the safety improvement EA commitment to CNSC when it is placed in service in 2015. It will improve the reliability of powerhouse venting to prevent damage to safety related systems, structures, and components in the event of piping failure.
4. **Shield Tank Over Pressure Protection** will be used and useful once placed in service in 2015. Partial in-service amounts of $3.5M will be used and useful immediately as it prevents shield tank failure from over-pressurization under severe Beyond Design Bases Accidents (BDBA).
5. **Emergency Service Water Buried Services** will be used and useful once placed in service in 2015. The installation of a parallel buried line of piping will continue to supply cooling water to selected safety related systems when normal water supplies are unavailable for the removal of decay heat and preventation of subsequent process failure, which may result in release of raidiation to the public.

Other Miscellaneous Station Modification includes services to island the unit to

UNDERTAKING J14.4

Undertaking

To calculate the LUEC assuming an 82 percent annual capacity factor and a 65 percent annual factor, based on the high-confidence estimate of the total cost.

(Provide a modified LUEC calculation using the $12.9B estimate for both an 82% and a 65% capability factor)

Response

The table below displays the LUEC at 82% and 65% annual capacity factors, using the $10B high confidence estimate ($12.9B including interest and escalation).

	Economic LUEC (2013$)	Fully Allocated LUEC(1) (2013$)	Economic LUEC (2014$)	Fully Allocated LUEC (1) (2014$)
Base Case (88% ACF)	7.8	8.2	7.9	8.3
82% ACF Case	8.3	8.7	8.4	8.9
65% ACF Case	10.3	10.9	10.5	11.1

Note 1: Includes past-service costs for pension, OPEB and severance

almost all the energy from the balance of the other existing supply sources and the capacity from new simple cycle peaking units.

7. If imports were obtained as required as 'economy sales' wouldn't they be at the average of sellers cost and buyers avoided cost wouldn't the cost be lower than gas generation costs?

A: In Ontario "economy sales" are required to flow through the IESO administered market and would be set at the Hourly Ontario Electricity Price (HOEP).

8. Please indicate whether OPA has analysed the option of closing Pickering A (which has far worse value for money performance) rather than all 6 reactors and provide any such analysis.

A: The OPA has not analyzed the option of closing Pickering A.

ED INTERROGATORIES (ALL)

1. According to Tab 4 (p. 8) in the Document Book (Exhibit K6.3), the costs of the OPA's energy conservation programs between 2015 and 2020 will be 3.5 to 4 cents per kWh. Can you confirm those estimates?

A: The Tab referenced is a slide contained in a 2013 LTEP module developed by the OPA ("2013 LTEP Module 4: Cost of Electricity Service"). The slide summarizes OPA estimates of levelized energy efficiency program costs and demand response costs and includes those costs that are recovered from electricity ratepayers (i.e. excludes the equipment investments made by the customer implementing the conservation initiative). For the period 2015 – 2020, the OPA's estimate of levelized energy efficiency program costs ranges between 3.5 to 4 cents per kWh.

2. Can the OPA confirm that the fuel and operating costs of a natural gas-fired combined-cycle power plant are approximately 3.8 cents per kWh assuming a gas price of $5/MMBTu? (Our calculation is based on Tab 5 (p. 9) of the Document Book (Exhibit K6.3), which contains an OPA interrogatory response. The response shows the fuel and operating cost of a natural gas-fired combined-cycle power plant assuming a gas price of $8/MMBTu. Adding up the circled numbers, the total operating costs would be approximately 5.9 kWh. If we assume a price of $5/MMBTu, the fuel cost would decrease by 5/8ths from 5.6 to 3.5 cents per kWh, which would result in an operating cost of 3.8 cents per kWh.)

A: The information in the referenced interrogatory was developed by the OPA in 2007/2008. The OPA's current estimate of VOMA for a combined cycle plant in 2014$ is $5.50. In addition, the OPA's current estimate is that the heat rate for a new combined cycle plant is closer to 7,150. Based on these assumptions, the fuel cost of a new natural gas-fired combined cycle generator at a natural gas price of $5/MMBTu would be approximately $36/MWh. Adding VOMA costs of $5.50/MWh to this fuel cost would result in a total fuel and VOMA cost of $41.50/MWh. This estimated fuel and VOMA cost does not include capital.

Please note the question seems to contain a written typo/error: the question indicates that a reduction of natural gas price from $8/MMBTu to $5/MMBTu would represent a decrease of 5/8ths (five eights).

3. Tab 6-A of the Document Book (Exhibit K6.3) includes Chapter 16 from a February 2014 report of the Quebec Energy Commission. According to page 183 (page 30 of the Document Book), Table 16.2, Hydro Quebec will be exporting 20.1 TWh of electricity at 3 cents per kWh in 2014 and 25.4 TWh of electricity at 3 cents per kWh in 2016. Do you have any reason to doubt the accuracy of these figures?

A: The OPA understands table 16.2 to indicate that the Commission sur les enjeux énergétiques du Québec estimates that Quebecers will lose between $817M and $1434M if Quebec power is sold at 3 cents per kWh in the period from 2014 to 2022.

4. How much of OPG's potential water power generation will be foregone (spilt) in 2014 and 2015 due to the surplus base-load generation resulting from Pickering GS?

A: As indicated in its June 17, 2014 response to GEC, in its 2012 assessment, the OPA's reference scenario with Pickering continued operation saw a total displacement of approximately 9 TWh of energy production from renewable and CHP resources between 2013 and 2020 compared to a reference scenario without Pickering continued operation. In the OPA's 2014 analysis, which reflects the demand forecast described in the government's 2013 Long-Term Energy Plan as well as other ongoing updates to the OPA's supply/demand outlook, the total amount of displaced renewable and CHP energy production between 2014 and 2020 was estimated to be approximately 5 TWh.

Out of the nearly 5TWh of displaced renewable and CHP production between 2014 and 2020 that was estimated in the OPA's 2014 analysis, 1.2TWh of that total would be displaced in 2014 and 2015. OPA further estimates that waterpower would represent 52% of the total of 1.2TWh displaced in 2014 and 2015 while wind would represent 34%. Displaced CHP production would account for 9% of the total, while biomass and solar displacement would account for 3% and 2%, respectively.

In conducting its analysis, the OPA did not specifically monitor the ownership/operatorship of the generating resources that might be displaced and therefore cannot at this time advise as to how much of the estimated waterpower displacement could specifically be attributed to OPG waterpower resources.

5. How much solar and wind generation will be curtailed in 2014 and 2015 due to the surplus base generation resulting from Pickering GS?

A: Please see the response to the question above.

6. Can the OPA confirm that the LUEC for a representative natural gas-fired combined heat and power plant would be approximately 4.7 cents per kWh assuming a gas price of $5/MMBTu and an average annual capacity factor of 90%? (Our calculations are as follows: The OPA interrogatory response referred to in Exhibit K6.3, indicates a LUEC of 6 ¢/kWh assuming a commodity cost of $8/MMBTU and an average annual capacity factor of 90%. Reducing the fuel cost by 5/8 (from 3.4 ¢/kWh to 2.1 ¢/kWh) brings the cost down by 1.3 ¢/kWh to 4.7 ¢/kWh.

A: The OPA's current estimate of LUEC for a representative natural gas fired CHP is $102.50/MWh, if assuming $5/mmBTu gas, and is based on a 50% acf, typical of Ontario facilities under OPA contract.

If 90% acf is assumed the LUEC would be $74.5/MWh.

This information is based on the latest actual procurement and operational experience in Ontario with the factors outlined below.

Assumptions

Inflation (%)	2%
Real Social Discount Rate (%)	4%
Nominal Social Discount Rate (%)	6%
Natural Gas Price ($/MMBtu)	$5.0

LUEC Component Breakdown

Components	50% ACF	90% ACF
Capital and Fixed ($/MWh)	$63.0	$35.0
Fuel ($/MWh)	$33.0	$33.0
VOMA ($/MWh)	$6.5	$6.5
Total ($/MWh)	$102.5	$74.5

Commission sur les enjeux énergétiques du Québec

MAÎTRISER NOTRE AVENIR ÉNERGÉTIQUE

Pour le bénéfice économique, environnemental et social de tous

Roger Lanoue
Normand Mousseau
Coprésidents

2 février 2014

UN QUÉBEC POUR TOUS

Québec

16.2 HYDRO-QUÉBEC'S SURPLUSES

The fact that Hydro-Québec generates surplus energy has influenced a large number of the submissions filed with the Commission. There is some confusion in the matter seeing as there exists two types of surpluses.

16.2.1 Hydro-Québec's surpluses Production: reserves for export

In 2012, Hydro-Québec Production generated surpluses of approximately 30 TWh under average runoff conditions. A "surplus" is defined as excess production with respect to the 165-TWh "heritage pool" agreement made with Hydro-Québec Distribution and with respect to certain other obligations—which remain minor for the time being—in Québec and Vermont. This excess production is destined for export.

The Commission estimates at approximately 10 TWh the electricity that is sold at higher prices during peak periods and therefore generates interesting returns: these can therefore not be construed as "surpluses" that result from inefficient planning or are undesirable (Figure 16.1). However, the additional TWh—20 TWh in 2012[123], including the surpluses generated by Hydro-Québec Production and Hydro-Québec Distribution—cannot be sold during peak periods because the interconnections with neighbouring markets are currently saturated. These additional TWh can therefore only be sold during off-peak (or base) periods at prices that are too low to ensure the profitability of the most recent investments made to increase electricity production capacity.

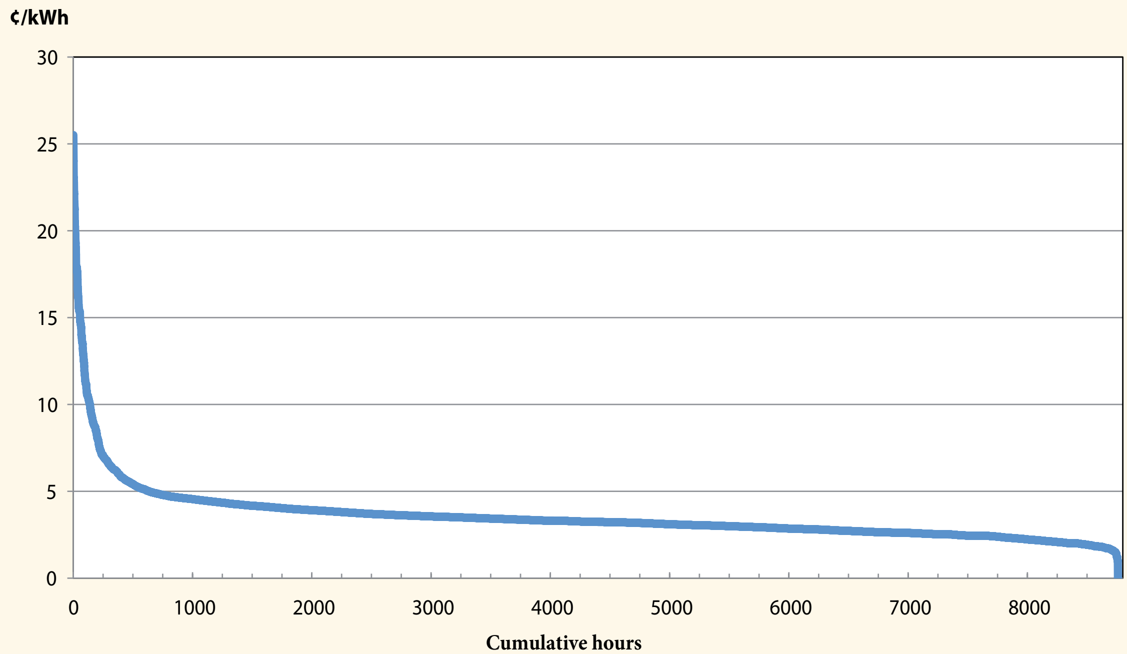
Since 2007, export prices—during both base and peak periods—have declined sharply (Table 16.1) to the point where only the electricity sold during peak periods is profitable. Hydro-Québec Production and the Québec government had not adequately identified four factors that explain the current situation.

1. Because of shale gas operations, beginning in 2008, the sharp decrease in the price of natural gas led to an important decrease in electricity prices in the northeastern United States. Seeing as natural gas is used to generate most of this market's electricity, the price of electricity is also determined by the price of natural gas. As a result, when the price drops, this

123. As shown in Table 5.2, the 30 TWh exported in 2012 are much higher than the historical trend. The Commission therefore arrived at the conservative estimate that the surpluses generated in 2012 under average runoff conditions were rather of 12.2 TWh. This is the value that was used to carry out the analysis presented in Section 16.3.

FIGURE 16.1

Hourly price of electricity at the interconnection between New York State and Québec, in decreasing order of price, for the 8,760 hours making up a full year



Remarks: This graph is based on all transactions (import and export) made at this interconnection.

The year can be mapped in three periods: the high peak, i.e., the first 300 hours during which electricity sells at very high prices on the market; the peak period, i.e., the first 1,000 hours during which the average price remains profitable for the producer; and the base, i.e., 7,760 hours during which prices are relatively stable but very low.

Note that the prices shown here concern a single interconnection with New York State. They exclude losses and congestion costs and do not represent what Hydro-Québec obtains for all of the electricity it exports or what it pays for importing electricity at peak times during the winter.

Source: *NYISO, Market and Operational data, Day ahead Market Location based marginal price pour HQ Gen Import,* from July 1, 2012 to December 13, 2013. http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=dam_lbmp_gen)

TABLEAU 16.1

Hydro-Québec Production's net electricity exports (2008–2012)

	2008	2009	2010	2011	2012
Net reservoir outflows (TWh)	15,2	18,5	12,6	20,8	30,1
Net exports (M$)	1 484	1 258	1 034	1 134	1 233
Unit contributions (¢/kWh)	9,8	6,8	8,2	5,4	4,1

Remark: The unit contribution is calculated by dividing export revenue by net electricity exports This calculation does not take into account the fact that Hydro-Québec purchases electricity on international markets when prices are very low and later resells it during peak periods. This enables it to boost its profits without increasing its net reservoir outflows.

Source: Brief to the Commission sur les enjeux énergétiques du Québec, Hydro-Québec (2013).

automatically results in lower sales prices for Hydro-Québec Production's surplus energy.

2. The 2008 financial crisis and the deep recession that followed led to the disappearance of many energy-intensive industries in Ontario and the northeastern United States, thereby dragging down the demand for electricity and shrinking the export market.

3. Although the distributors of neighbouring grids are now obliged to purchase renewable electricity, all state governments nevertheless encourage local production—or U.S. production at the very least. Except for a very minor purchase of electricity generated by wind energy negotiated by Hydro-Québec Production, our neighbours' policies considerably restrict Québec's ability to charge more for the renewable wind or hydroelectric energy that it exports.

4. The direct and indirect subsidies granted by certain American states and Canadian provinces for the production of wind and photovoltaic energy have a double paradoxical effect: on the one hand, these subsidies lead to sharp decreases in the price of energy imports because they meet domestic demand; on the other hand, they lead to increases in the electricity rates paid by clients who are forced to foot the bill of the high cost of generating energy from alternative sources.

This is how the market has been evolving for six years now, and electricity prices on the American markets—for electricity sold during both peak and base periods—have gone down sharply. These prices do not justify building new power plants to export the electricity they would generate. In fact, if these factors had been identified in 2008, there is reason to believe that construction of the Romaine complex would have never been authorized.

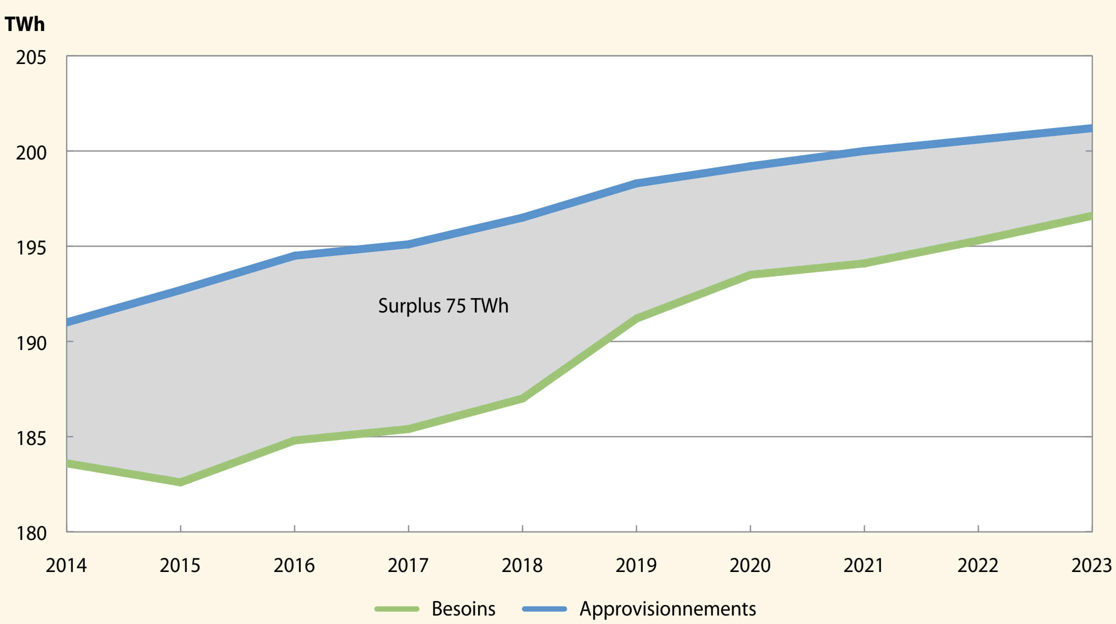
16.2.2 Les surplus d'Hydro Québec

Hydro-Québec Distribution doit acheter suffisamment d'électricité pour satisfaire la demande de l'ensemble des clients du Québec. Ses surplus sont un peu mieux connus puisqu'ils sont discutés périodiquement et publiquement devant la *Régie de l'énergie*.

Tout distributeur d'électricité doit être capable de prévoir la demande avec le plus d'exactitude possible. Il doit aussi négocier un portefeuille de contrats au meilleur prix avec les producteurs; ce portefeuille doit lui permettre d'optimiser la planification et la gestion de ses achats avec un

FIGURE 16.2

Prévision des surplus énergétiques d'Hydro-Québec Distribution (2014-2023)



Source : Plan d'approvisionnement 2014-2023 d'Hydro-Québec Distribution

16.4 A $1.2 BILLION SUBSIDY EACH YEAR

The PASO also introduced a baseline used to evaluate the cost of current and future supply contracts already entered into by *Hydro-Québec Production and Hydro-Québec Distribution.*

Figure 16.3 shows the projected surpluses, under average runoff conditions, until 2028. Seeing as the sharp decrease in electricity prices in the northeastern United States is a known fact since 2008, the Commission only took into account the generating infrastructure commissioned since then.

Based on electricity demand trends between 2005 and 2012, the Commission assumes that demand shall remain stable in the coming years and that the increase of 10.1 TWh that Hydro-Québec Distribution forecasts by 2023—its forecasts have been historically too high—reflects the hope of being able to sell the surpluses, undoubtedly at a reduced price.

16.4.1 All energy surpluses, even renewable, come at a high cost

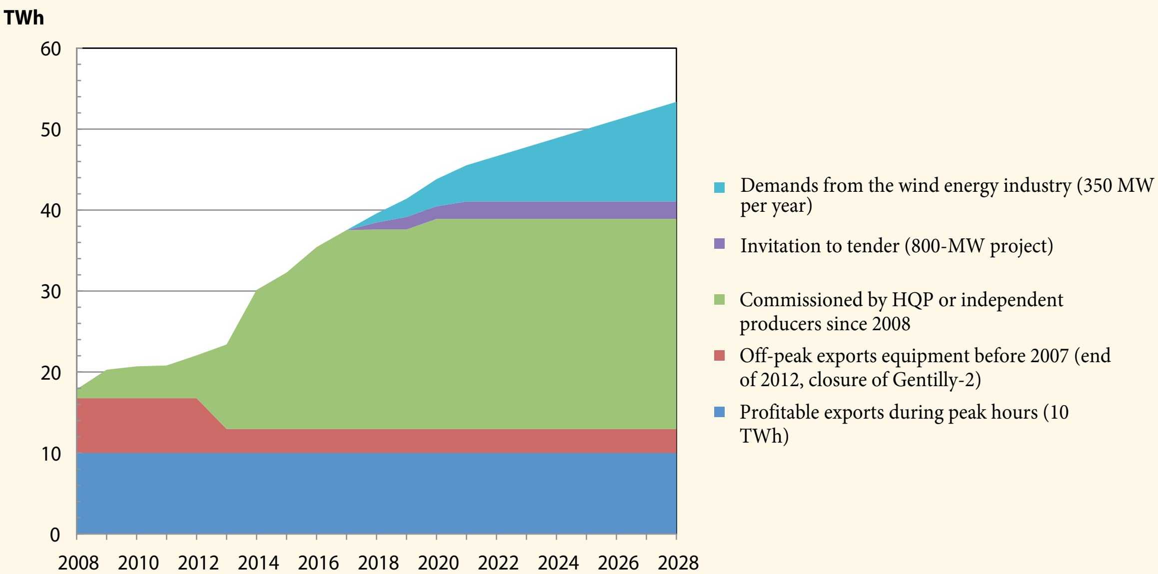
So far, Québec consumers and taxpayers have not really felt the impact of the new infrastructure commissioned following invitations to tender for wind energy, biomass cogeneration, small hydropower and new large hydroelectric dam projects given the generating infrastructure is only beginning to be put in operation. In 2012, all of these sectors combined generated only 5.3 TWh of electricity. In the coming years, this production will increase fivefold: over 10 TWh in 2013, 17 TWh in 2014 and 28 TWh in 2020, if all projects currently underway are taken into consideration, including the Romaine project and the 800-MW wind energy project announced by the government in the spring of 2013.

Since 2008, Hydro-Québec Distribution purchases the bulk of this production under long-term contracts at pre-determined prices varying between 7.5 ¢/kWh for small hydropower and up to 12.5 ¢/kWh in the case of certain wind energy contracts. These prices are much higher than the PASO (estimated at 3 ¢/kWh for 2013). This marked difference between the purchase and sale prices results in a deficit that is paid by consumers through sharp rate hikes.[126]

126. The Commission assumes that all electricity surpluses can be exported. It is far from certain that the interconnections and neighbouring grids will be capable of supporting an additional 10 or even 20 TWh in the coming years. If this is not the case, energy will need to be stored in reserves and power spills may even be necessary in the long term.

FIGURE 16.3

Québec's annual surplus destined for export (2008–2028)



Source: Calculations of the Commission based on data provided by Hydro-Québec Production.

Furthermore, the cost of Hydro-Québec Production's new infrastructure is set at between 5.6 ¢/kWh and 6.4 ¢/kWh; losses on the PASO would be accounted for as losses for the government, i.e., for taxpayers.

These sums could marginally vary according to growing demand in Québec or increased off-peak electricity prices in the United States. However, they remain high in any case.

The scenario used by the Commission is shown in Figure 16.3: losses are soaring. In 2012, $240 million were granted in electricity production subsidies. This amount reached more than $500 million in 2013 because of subsidies that allow producers to receive (or amortize in the case of Hydro-Québec Production) close to 8 ¢/kWh on average for electricity sold at a loss by Hydro-Québec Production for only 3 ¢/kWh.

Beginning in 2016, Quebeckers will have to pay close to $1.2 billion annually to fund the shortfall between the price at which Hydro-Québec Distribution purchases electricity and the amortization of Hydro-Québec Production's new generating plants, on the one hand, and Hydro-Québec Production's export sales price, on the other hand. This amount will climb to close to $1.4 billion in 2020, when the entire Romaine complex as well as the subsidies for the 800-MW wind energy call for tenders announced in the spring are included in the calculation.

TABLEAU 16.2

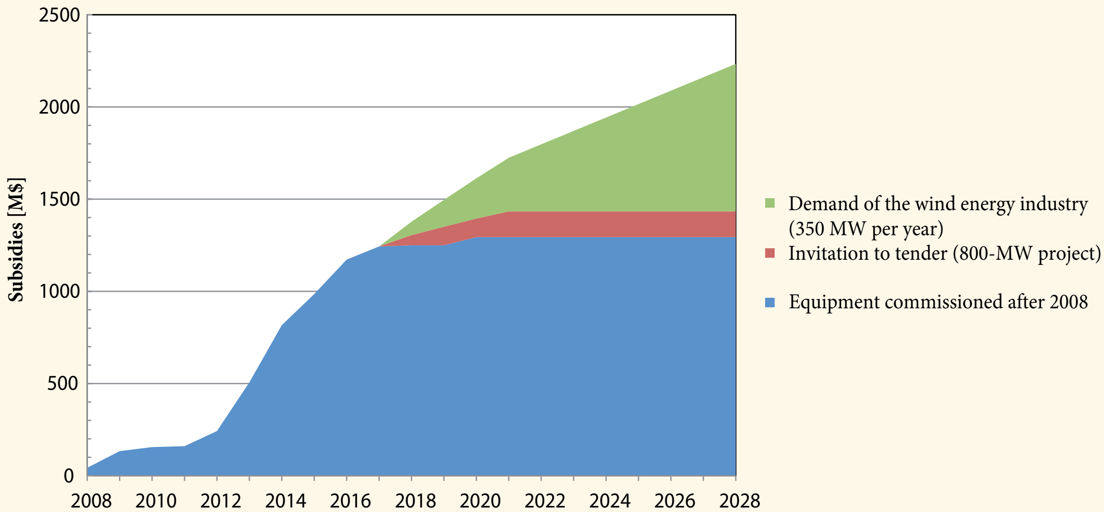
Total surpluses of Hydro-Québec Production and Distribution and shortfall for Quebeckers resulting from supplies purchased since 2008 and exported at the PASO (estimated at 3 ¢/kWh)

	2014	2016	2018	2020	2022
Surpluses (beyond the 10 TWh peak) (TWh)	20,1	25,4	28,5	30,5	31,1
Supplies in use since 2008 (TWh)	17,2	22,5	25,5	27,5	28,1
Loss for Quebeckers (sale price of 3 ¢/kWh) ($M/ yr.)	817	1 172	1 305	1 395	1 434

Sources: Hydro-Québec and calculations made by the Commission.

FIGURE 16.4

Direct subsidies for electricity generation equipment commissioned since 2008 (2008–2028)



Source: Calculations made by the Commission based on data provided by Hydro-Québec Distribution.

Likewise, to keep the wind energy industry afloat by adding an additional 350 MW per year until 2025, Québec consumers will have to cover the difference between the industry's purchase price of 9.5 ¢/kWh and the market price set by the PASO. This situation is similar to the fiasco that occurred in Ontario. By 2025, the shortfall for Québec taxpayers will have reached $2 billion per year.

In this context, the Commission has no doubt that the Québec government must immediately cease issuing invitations to tender for new electricity production facilities and cancel contracts currently being renewed or renegotiate them on the basis of the PASO whenever possible.

la qualité du milieu est significatif. Par ailleurs, les réseaux existants qui font périodiquement l'objet de travaux majeurs de mise à niveau en milieu densément occupé devraient être enfouis à cette occasion.

16.10.5 L'efficacité énergétique du réseau électrique

L'efficacité énergétique ne s'applique pas seulement aux consommateurs. Certains intervenants ont souligné avec raison l'importance de minimiser les pertes électriques sur les réseaux des transporteurs et des distributeurs. Ainsi, les pertes de *TransÉnergie* sont d'environ 5 %, et celles de *Hydro-Québec Distribution*, de 5 % à 6 %. La *Régie de l'énergie* doit intégrer au calcul de la base tarifaire le coût des équipements et des programmes visant à minimiser le vol et les pertes d'énergie dans le réseau. Autrement, *Hydro-Québec Distribution* et *TransÉnergie* pourraient être tentés d'acheter des équipements moins chers qui sont parfois aussi moins performants ou à tolérer le vol d'énergie, comme on le constate en certains endroits aux États-Unis.

RECOMMANDATIONS

Électricité

40. Qu'un Prix d'achat fixe selon les opportunités de marché (PASO), correspondant à la valeur de l'électricité sur les marchés d'exportation hors pointe, soit utilisé pour évaluer la rentabilité:

- **de tout nouvel achat d'approvisionnement par *Hydro-Québec Production* ou *Hydro-Québec Distribution*;**
- **de nouveaux projets hydroélectriques d'*Hydro-Québec Production*;**

Et pour déterminer la valeur de référence

- du renouvellement de tout contrat d'approvisionnement signé par *Hydro-Québec Production* ou *Hydro-Québec Distribution*, incluant le renouvellement de l'ensemble des contrats APR 91;
- de l'achat d'électricité provenant de petits autoproducteurs privés (50 kW et moins);
- des programmes de maîtrise de l'énergie;
- **des nouveaux marchés québécois où *Hydro-Québec Distribution* pourrait vendre ses surplus à court ou moyen terme.**

40.1 Que le PASO soit fixé par la *Régie de l'énergie* sur recommandation de *Hydro-Québec Distribution*, sur la base du prix moyen des ventes de *Hydro-Québec Production* aux marchés externes durant l'année précédente, excluant les ventes en période de pointe et les ventes contractuelles fermes.

40.2 Qu'*Hydro-Québec* ait l'obligation d'acheter les surplus liés à l'autoproduction à petite échelle, c'est-à-dire 50 kW ou moins, sans contrat d'approvisionnement, mais au PASO.

41. Que le gouvernement et *Hydro-Québec* agissent immédiatement pour cesser tout ajout de capacité de production d'électricité:

41.1 Que soit étudiée sans délai l'opportunité de suspendre tout nouvel investissement dans l'augmentation de la capacité de production d'électricité, incluant les projets Romaine-3 et 4, ainsi que les contrats d'approvisionnement en éolien, en cogénération et en petite hydraulique pour les infrastructures non encore construites;

41.2 Que soit soumis à l'approbation de la *Régie de l'énergie* tout développement de nouvelle centrale hydroélectrique, selon des paramètres fixés par le gouvernement du Québec;

UNDERTAKING JT1.14

Undertaking

To provide a written response to Environmental Defence interrogatory No. 15, parts (a) and (b).

Response

a) OPG's payment amounts application for the 2014 - 2015 period was prepared on the basis of a single overall nuclear rate. OPG does not calculate separate rates for Pickering and Darlington. OPG would note that ED's methodology for allocating costs strictly based on nuclear production is inconsistent with OPG's approved allocation methodology (see Ex F3-1-1) and that fuel and depreciation costs are not classified as "OM&A" which is why OPG excluded those two cost elements from its previous interrogatory response.

OPG benchmarks its financial performance against other utilities. The EUCG Non-Fuel Operating Cost per MWh ("NFOC") represents one such metric and includes Base OM&A, Outage OM&A, Project OM&A, Corporate Support & Administrative costs and some component of centrally held costs (excluding OPEB and Pension costs). NFOC is derived by OPG for both Darlington and Pickering to allow OPG to benchmark financial performance and operating costs by station.

OPG does not have a station-level allocation methodology for rate making purposes nor has it allocated "generic" costs such as property tax, or centrally held costs for Pickering and Darlington.

b) OM&A costs, consistent with the industry NFOC metric, were provided in the previous interrogatory response. OPG did not provide fuel costs in the original response as fuel costs are not considered OM&A costs under industry standard metrics. However, the following table provides actual and projected Pickering annual fuel costs for the 2010 - 2015 period.

Pickering	2010	2011	2012	2013	2014	2015
Fuel Cost per MWh ($ per MWh)	4.33	4.85	5.77	5.81	6.02	5.93

Additional Response

As directed by the Board in Procedural Order #9 dated May 16, 2014, OPG has prepared Attachment 1, which provides an "OM&A" unit cost for the Pickering Nuclear station consisting of base, outage and project OM&A expenditures; fuel costs, and depreciation expense for ther years 2010-2015. With the exception of "Depreciation – Generic" existing internal allocations were available. OPG does not have an available allocation of those components that make up "Depreciation –Generic" and therefore an allocation was made based on Pickering's generation as a percentage of total generation as proposed by Enviromental Defences in Exhbit L-6.3 ED-15.

Pickering Unit Operating Cost Summary 2010-2015

	2010		2011		2012		2013		2014		2015	
	Actual	Actual	Actual	Actual	Actual	Actual	Budget	Budget	Plan	Plan	Plan	Plan
	$	$/Twh	$	$/Twh	$	$/Twh	$	$/Twh	$	$/Twh	$	$/Twh
Base, Outage and Project OMA	984.6	51.3	998.7	50.7	900.9	43.5	908.2	43.0	940.9	44.2	923.9	42.2
Corporate Support & Adminstration	127.1	6.6	127.5	6.5	227.8	11.0	239.3	11.3	230.3	10.8	218.9	10.0
Centrally Held Costs	92.6	4.8	162.3	8.2	205.6	9.9	217.3	10.3	246.5	11.6	246.0	11.2
Asset Service Fee	12.4	0.6	11.6	0.6	12.7	0.6	12.5	0.6	12.8	0.6	14.7	0.7
Depreciation - Pickering	129.6	6.8	147.1	7.5	156.4	7.6	122.4	5.8	133.0	6.2	143.0	6.5
Depreciation - Generic	29.4	1.5	22.3	1.1	65.6	3.2	45.0	2.1	45.4	2.1	50.2	2.3
Fuel Costs	84.0	4.4	95.4	4.8	119.6	5.8	127.6	6.0	128.2	6.0	130.0	5.9
Total	1,459.7	76.0	1,564.9	79.4	1,688.6	81.6	1,672.3	79.3	1,737.1	81.6	1,726.7	78.8

UNDERTAKING J12.3

Undertaking

To make best efforts to identify what percentage of the $2.5 billion being added to the rate base for newly regulated hydro facilities is attributable to revaluation of costs of the transfer from Ontario Hydro to OPG, or to provide a proxy if the number cannot be provided.

Response

While OPG does not believe the requested information is relevant in the context of the current application, its high-level estimate is that approximately 50%-60% of the December 31, 2013 net book value of $2,525M for the newly regulated hydroelectric property, plant and equipment (from Ex. A2-1-1, Att. 6, p. 1) is attributable to the difference between the cost of these assets to OPG and their net book value as reflected in the financial statements of Ontario Hydro for the final period of operations.

In calculating this estimate, OPG has applied a ratio equal to the net book value of all hydroelectric assets on Ontario Hydro's March 31, 1999 financial statements divided by the opening book value of these assets on OPG's financial statements (as of April 1, 1999) to a valuation of the newly regulated assets in 1999 for tax purposes. OPG has also assumed a proxy average remaining depreciation life of approximately 58 years for these assets at April 1, 1999, as calculated based on the ratio of their actual December 31, 2013 gross cost of $3,266.0M (from Ex. L-1.0-1 Staff-002, Att. 1, Table 2, col. (e), line 9) and the associated 2013 actual depreciation and amortization expense of $56.6M (from Ex. L-1.0-1 Staff-002, Att. 1, Table 3, col. (b), line 9). This assumed life for depreciation allowed OPG to estimate how much of the revaluation amount had been amortized away prior to December 31, 2013.

Ontario Power Generation was established through the purchase of a set of assets on April 1, 1999. This set of assets was financed by OPG through a combination of debt and equity. Canadian GAAP required the use of purchase accounting to assign values to specific assets at the inception of OPG. It is that cost, the cost reflected in OPG's audited financial statements, that is recoverable from generating revenues from those assets over time.

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

5.2 Construction Work In Progress

OPG's application included a proposal to include Construction Work in Progress ("CWIP") for the DRP in rate base. This would result in an addition to rate base of $125.5 million in 2011 and $306.0 million in 2012. These additions to rate base would receive the approved weighted average cost of capital which would result in a revenue requirement of $11.1 million in 2011 and $26.8 million in 2012 for a total of $37.9 million for the test period. OPG also proposed that any recovery of depreciation on this capital would be deferred until the assets come into service. OPG maintained that there would be benefits to ratepayers from this proposal through rate smoothing and lower credit costs.

Two expert witnesses filed reports on this issue – Mr. Ralph Luciani of Charles River Associates on behalf of OPG and Mr. Paul Chernick on behalf of GEC. Both appeared as witnesses at the hearing.

Mr. Luciani's report was largely a presentation of examples in the US where CWIP has been allowed for the development of nuclear facilities and a discussion of their potential as precedents in OPG's situation. Mr. Luciani's report did not describe or discuss the various circumstances in which states had decided not to allow CWIP.

Mr. Chernick's report suggested that the cases in which CWIP has been allowed in the US were not applicable to OPG because the circumstances are quite different. He also reviewed the circumstances in several US jurisdictions which had decided not to allow CWIP, and suggested that they were more akin to the situation in Ontario.

OPG's position was that inclusion of CWIP in rate base is warranted in this case because it meets the criteria for qualifying investments specified by the Board in its EB-2009-0152 report, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, dated July 15, 2010 (the "Report").

OPG argued that the Board should take the criteria set out in the Report into account in evaluating the CWIP proposal and offered the following evidence in support of each:

> **The need for the project**: The Government of Ontario has endorsed the need for the project by concurring with OPG's decision to proceed with the project and by including it in the government's energy plans.

The public interest benefits of the project: The Minister's support and approval of the project is indicative that it is in the public interest. OPG noted that the Government of Ontario has indicated its support for the DRP, and that this support should be sufficient for the Board to conclude that the DRP is needed and in the public interest. OPG also pointed out that there is no provision in the Act or related regulations for the Board to grant approval for the project. While not currently obligated to undertake the DRP, OPG believes that Ontario's energy needs will require OPG to proceed with the project.

The overall cost of the project in absolute terms: The project will cost between $6 billion and $10 billion and is the largest project being undertaken by a regulated utility in Ontario.

The risks or particular challenges associated with the completion of the project: The project's risks and challenges are broadly similar to those faced by *Green Energy and Green Economy Act* ("Green Energy Act") projects, including the potential for delays, public controversy and the recovery of costs.

The cost of the project in proportion to the current rate base of the utility: The project's cost range of $6 billion to $10 billion is greater than OPG's $4 billion nuclear rate base for 2012. The upper bound of the range is greater than OPG's combined nuclear and hydroelectric rate base of $7.8 billion.

The reasons given for not relying on conventional cost recovery mechanisms: The reasons are rate shock, impact on credit metrics and the subsidy resulting from the difference between Interest During Construction ("IDC") rate and the Allowance for Funds Used during Construction ("AFUDC") rate. Rather than large increases of $350 million to $550 million in the revenue requirement when the DRP is added to rate base in 2020 and in subsequent years, the revenue requirement would increase more gradually starting in 2011. OPG's scenario would have rates increasing by 1 to 1.8% per year each year starting in 2011, rather than a few years with 5 to 10% increases starting in 2020.

Whether the utility is otherwise obligated to undertake the project: While OPG was directed by its shareholder to study the refurbishment of the Darlington units, it has not received a directive to complete the project. Pursuant to the

Report, a utility will not have to establish that “but for” CWIP treatment, the project will not proceed.

OPG argued that the inclusion of CWIP in rate base for the DRP meets the criteria for qualifying investments specified by the Board in the Report.

OPG’s case for CWIP was supported the PWU and the Society. The PWU submitted that this proceeding is not the forum to re-hear arguments about the appropriateness of alternative regulatory mechanisms but whether the alternative mechanisms contemplated by the Report should be applied in the case of the DRP. PWU criticized Mr. Chernick’s evidence as a re-argument of matters decided in the Report rather than a consideration of the merits of the case presented by OPG.

Other parties, including Board staff, submitted that the Board should deny OPG’s request.

First, parties disagreed with OPG’s claim that the DRP falls within the scope of the Report as a qualifying investment, and that the CWIP proposal should be evaluated on this basis. These parties argued that the DRP is not a Green Energy Act related investment. They noted that the Report deals with rate-regulated activities of distributors and transmitters and that despite OPG’s request during the Board’s consultation on the Report, the scope of the Report was not expanded to include generation investments.

In reply argument, OPG submitted that the Report provides for the consideration, on a case-by-case basis, of applications to include CWIP in rate base in advance of a project being declared in-service. OPG sees its proposal as consistent with the Chair of the Board’s statement of July 3, 2009 regarding the removal of barriers to infrastructure investment in Ontario.

Intervenors also argued that when evaluated on the basis of the factors suggested by OPG, the DRP did not warrant alternative regulatory mechanism (i.e. CWIP) treatment, arguing that:

- OPG had failed to demonstrate that significant rate shock would be avoided;
- It would be imprudent to recover costs when overall projected costs are not yet defined;

- It would be premature to grant recovery when the project lacks full authorization to proceed, as OPG's Board of Directors has only given permission to proceed with the definition phase of the project;
- The public interest would not be served since the proposed treatment is more costly to ratepayers on a Net Present Value basis;
- Proposals which front-end load costs are disadvantageous to rate-payers since ratepayers' financing costs are higher than OPG's;
- Intergenerational inequity results when ratepayers are asked to pay for costs and there is no corresponding benefit for them;
- OPG's existing credit risk has been unaffected by the DRP expenditures underway; and
- No evidence has been provided that any downward evaluations are forthcoming.

OPG argued that the Board should not consider any of the arguments regarding intergenerational inequity, the "used and useful" principle and differences in ratepayer and OPG financing costs as these have already been dealt with in the Report.

CCC and other intervenors commented that, based on OPG's own analysis, the rate shock would not be that significant, and in the meantime ratepayers will be paying for 10 years for an asset that is not yet in use.

CCC argued that OPG's concern with its credit metrics was hypothetical and unsupported by any evidence of the impact of not having CWIP. In response, OPG quoted Fitch Ratings, that "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk" and referenced Standard and Poor's observation that OPG had weak cash flow metrics. OPG stated that it is not surprising that it would not be able to quantify the impact of the DRP on its credit metrics until the Board's decision is issued, project financing finalized and rating agencies have had the opportunity to complete the assessment. OPG also pointed out that the incremental risk associated with the DRP is not reflected in OPG's current credit rating and cost of capital.

CME also observed that the timing of the request for CWIP treatment is inopportune, given the increases in electricity bills being experienced by customers, but suggested that OPG may wish to re-apply for this treatment once electricity rates have stabilized.

Board staff submitted that in the event the Board accepts the inclusion of CWIP in rate base, the return should be limited to interest costs similar to the treatment afforded Hydro One in the EB-2006-0501 decision. OPG argued that its circumstances are different from those faced by Hydro One, and so interest rate treatment should not apply. OPG submitted that as a result of this suggestion, OPG's shareholder would be subsidizing the DRP, which OPG estimates to be $200 million to $300 million.

Board Findings

The Board finds that the Report is clear that the policy could apply in other circumstances beyond the Green Energy Act and beyond transmission and distribution infrastructure. However, the Board finds that OPG's request for CWIP is premature, given that the DRP is only at the definition stage.

The Board notes that its policy, as set out in the Report, contemplates the adoption of these mechanisms in the context of an overall approval of a project, generally either through a leave to construct application or through a rates case. The Board notes that this is consistent with the approach taken by US jurisdictions that allow CWIP in rate base, other than those which allow for CWIP through legislation. As the Board is not considering the overall scope of the DRP at this time, it finds that it is premature to adopt any special treatment. The Minister's letter indicating support for the project is not sufficient for this purpose. While it may be persuasive, it does not bind the authorities that will need to approve the project. At the very least, it will require some form of approval under the *Environmental Assessment Act*, and will have to be included in the IPSP.

In filing Mr. Luciani's report in support of its position, OPG sought to persuade the Board that using CWIP to finance nuclear power plants was becoming the accepted approach in US jurisdictions. The Board allowed Mr. Luciani to give evidence despite the reservations expressed by several of the intervenors about his independence given the nature of his retainer which they asserted cast him in the role of advocate. The Board ruled that the evidence would be allowed but that it would take the nature of his retainer into account when considering the weight to be given it.

Of greater concern to the Board is the nature of Mr. Luciani's report itself. While his report did not purport to be a review of all US jurisdictions, it was a completely one-sided account of the issue as it included only those jurisdictions which had decided to allow CWIP and neglected to mention any that did not. In cross-examination, Mr.

Luciani admitted that there were many jurisdictions that had rejected CWIP as a funding mechanism. In the Board's view the contents of his report created a misleading impression about the level of acceptance of CWIP as a mechanism. The Board expects objectivity from independent expert witnesses.

In any event, the Board finds that most of the US jurisdictions that have allowed CWIP for nuclear plants have quite different circumstances than those facing OPG. The companies concerned are generally private sector operators who require incentives to build and the CWIP approvals have been granted in the context of overall project approvals. Neither of these circumstances applies to OPG.

The Board therefore gives little weight to Mr. Luciani's evidence and finds that it cannot be relied on by OPG as the underpinning for its request for CWIP.

The Board will not approve CWIP in rate base at this time. The Board is prepared to consider the proposal again in the future, but the Board will expect better evidence in support of the proposal. For example, prior to approval of CWIP, the Board would expect to see more persuasive evidence than was presented in this application as to the benefits for ratepayers in terms of improved credit metrics and rate smoothing. On the latter point regarding rate smoothing, the Board would expect to see additional evidence to support the proposition that ratepayers are better off if they begin to pay sooner for these large multi-year projects.

Decision **2002-072**

ATCO Gas, a Division of ATCO Gas and Pipelines Ltd.

Transfer of Carbon Storage Facilities

July 30, 2002

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2002-72: ATCO Gas, a Division of ATCO Gas and Pipelines Ltd.
Transfer of Carbon Storage Facilities
Application No. 1237639

Published by
Alberta Energy and Utilities Board
640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

Web site: <www.eub.gov.ab.ca>

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TRANSFER OF CARBON STORAGE FACILITIES **File No. 6405-19**

1 BACKGROUND

1.1 Introduction

By letter dated July 18, 2001 ATCO Gas, a division of ATCO Gas and Pipelines Ltd. (AGPL), filed an application with the Alberta Energy and Utilities Board (the Board) requesting approval of a process whereby the Carbon storage facilities and related producing properties (collectively referred to herein as "Carbon") owned by AGPL could be transferred to ATCO Midstream Ltd. (Midstream), an unregulated affiliated company. More particularly, the Application deals with ATCO Gas – South (AGS), a sub-division within ATCO Gas, which distributes and sells natural gas in franchise areas in southern Alberta and which includes Carbon in its rate base for rate making purposes. References herein to ATCO Gas refer to AGS, unless otherwise specified.

As a result of a pre-hearing meeting held on August 10, 2001 with respect to the proceeding dealing with the ATCO Group of companies Affiliate Transactions and Code of Conduct Applications (the Affiliate Proceeding), it was determined that issues concerning the Carbon transfer should be dealt with in a separate Carbon proceeding. Previously, in the Affiliate Proceeding, ATCO Gas had requested the Board to approve a leasing arrangement with Midstream for the use of Carbon. The Application superseded that request. In respect of the Affiliate Proceeding the Board issued Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues in Decision 2002-069, dated July 26, 2002, and will issue a further decision, Part B, dealing with Code of Conduct matters, in due course.

By letter dated August 14, 2001 the Board notified parties participating in the Affiliate Proceeding that associated issues involving transactions between AGS and Midstream that were otherwise being dealt with in AGS's recent general rate application (GRA) would instead be brought forward to the Carbon proceeding. Subsequently, by e-mail correspondence on August 20, 2002, the Board advised the same parties of a proposed schedule for the Carbon proceeding and requested that only those parties that wished to participate in the Carbon proceeding advise the Board accordingly. The Affiliate issues brought forward included the review of service agreements between ATCO Gas and Midstream for gas management, storage, and uncontracted capacity; the GRA matters included a review of forecasts for storage revenue and storage operations and maintenance costs.

To further support its request of July 18, 2001 for the removal of Carbon from regulation, ATCO Gas filed additional evidence on September 28, 2001. Collectively, the letters of July 18, 2001 and September 28, 2001 shall be referred to herein as "the Application".

1.2 Carbon History

1.2.1 Summary

The Carbon Glauconitic reservoir was discovered by a well drilled in 1955. In 1957 AGPL (then known as Canadian Western Natural Gas Company Limited (CWNG)) acquired rights in the Carbon field and in 1958 CWNG received a permit to construct a gathering system in the field and build a transmission line to Calgary. In 1959, in Decision 23616, the Board of Public Utility Commissioners, Alberta, stated "… this Board … is convinced beyond any doubt whatsoever that it was necessary for the company to acquire the Carbon gas rights and since they are used and useful in the operation of the company they are properly included in the rate base."[1]

From 1959 to 1967 CWNG used the Carbon reservoir to provide a peaking source to meet the peaking gas requirements of its customers. In 1967 CWNG applied for and received approval for the storage of gas in the Carbon field. In 1972, with a 20 year storage agreement with TransCanada Pipelines Limited, storage capacity underwent a major expansion. In the 1980s Carbon was the only commercial storage facility in Alberta. Carbon again underwent expansions in 1993, 1994 and 1995 and, presently, Carbon operations consist of twenty-four injection and withdrawal wells, one well with withdrawal only and a total of 9005 kilowatts (11,800 horse power) of compression.

1.2.2 Historical Observations

The Board believes it is instructive to consider how Carbon has been used by ATCO Gas in the past as a regulated asset in rate base, both in prior years and in more recent years. ATCO Gas provided in the Application a summary of extracts from various rate hearings and regulatory proceedings which indicates how and for what purposes it has historically used Carbon. Further, data was filed in the proceeding which indicates in some detail how Carbon has been used in the last five years. The Board has found it useful to consider all of this evidence in understanding the context of the past and more recent use of Carbon.

In the Application[2] AGS submitted the following extracts:

> **April 11, 1990 (1989-1999-1991 GRA)**
> Mr. Welsh stated on behalf of CWNG that there are essentially two reasons for storage. One is to take advantage of the price differential. Short-term spot prices in the summer are generally lower than long-term prices in the winter. The second reason relates to load factor consideration or having to purchase at a higher rate of take than can be absorbed by the market.
>
> **May 1990 (1989-1991 GRA Phase I)**
> CWNG submitted that Carbon is used to store and withdraw load factor differences, or differences between market demand supply. It also allows CWNG to take advantage of winter/summer price differentials. CWNG stated that it reassesses the use of the Carbon storage facility on a regular basis and attempts to provide the optimum economic use for the facility to the benefit of the Company and its customers.

1 Decision No: 23616, dated March 4, 1959, page 10.
2 Appendix B to the Application, dated July 18, 2001

Public Utilities Board Decision No. E93004
The City of Calgary submitted that it is unclear how and to what extent customers benefit form storage and suggested that a study be presented at the next GRA. CWNG stated that the purpose of increased storage utilization is to reduce gas costs and increase the contractual security of supply.

1993 DGA
In response to the Board direction in GRA Decision E93004 to demonstrate how storage facilities are used to minimize gas costs, CWNG submitted evidence on the benefits of storage. The first benefit noted was increased security of supply. CWNG submitted that storage withdrawals provide incremental supply and deliverability during peak winter demand periods when other supply options are limited. Second, storage creates flexibility for handling load and supply balancing and market changes due to weather. Third, storage gives CWNG the ability to contract gas at higher load factors. Summer storage injection increases summer demand, allowing CWNG to contract gas at the higher load factors directed in the marketplace. Fourth, gas cost savings due to summer and winter price differentials are associated with the use of storage. Last, storage provides increased control and flexibility for supply portfolio adaptations.

In recent years Carbon appears to have been used at least for operational supply purposes. The Board has reviewed five recent years of historical information filed in this proceeding[3] and has made some observations of aspects of Carbon's configuration and operation during the winter as it pertains to AGS. Some of the data from the record has been tabulated in the table that follows.

Winter Season	Total Winter Degree-days[4] Nov - Mar	AGS Capacity[5] (PJ)	% of Total Capacity[6]	AGS Deliverability[7] (TJ/Day)	% of Total Deliverability[8]
1996-97	3669	13.7	31.5	300	50
1997-98	3108	13.7	31.5	300	50
1998-99	2985	16.7	38.4	300	50
1999-00	2846	16.7	38.4	300	50
2000-01	3092	16.7	38.4	300	50

The winter of 1996-97 was the coldest of the five winter seasons being approximately 18% colder than the next coldest winter (1997-98) and 29% colder than the warmest winter (1999-00). This was at a time when AGS retained 31.5% of the working gas capacity and 50% of the deliverability for its own use. The withdrawals by AGS are observed to bear a correlation to the weather pattern expressed in degree-days throughout the winter, although with a lower working gas capacity than later in the 5 year period of data provided. The winter was coldest during the early part, November 15 to January 30, during which the withdrawals were the highest. It can also be observed that the total withdrawals at Carbon were roughly correlated with the weather pattern throughout the winter. ATCO Gas-North (AGN) also utilized some storage capacity.

3 CAL-AG.18; CAL-AG.19
4 CAL-AG.19
5 CAL-AG.5
6 Based on percent of 43.5 PJ
7 CAL-AG.5
8 Based on percent of 600 TJ/day (Transcript Vol. 7, page 716)

The winter of 1997-98 was the last winter before AGS increased its working capacity from 13.7 PJs and it still retained 300 TJ/day of deliverability. This winter was the reverse of the previous one, being relatively warm until January 3. It is observed from the data on the record that AGS made significant withdrawals from Carbon as the cold weather settled in. Again both AGS withdrawals and total withdrawals follow the trend of the degree-day pattern. This was the last year that AGN utilized capacity.

The winter of 1998-99 was the second warmest of the five seasons of data and the first year that AGS had increased its working capacity to 38.4% (16.7 PJ) of the total available storage capacity. Retained deliverability remained unchanged. There is a general correlation again between the weather and total withdrawals. Of note is that, at times, the data indicates that withdrawals by those other than AGS exceeded 300 TJ/day. Therefore, others must have used some of AGS's deliverability.

The winter of 1999-00 was the warmest of the five seasons of data on the record. Again a general correlation can be observed between the weather and the pattern of withdrawals by AGS. It is also the first winter that AGS appears to have set a flat withdrawal pattern (or a ceiling) starting in early January. Of note again is that the data indicates that withdrawals by those other than AGS exceeded 300 TJ/day, again indicating use by others of the deliverability reserved by AGS.

The winter of 2000-01[9] was not an unusual one, having the coldest periods in December and February. While AGS retained 300 TJ/day of deliverability, it did not use it and this was the first year it used a flat withdrawal pattern each month without responding to the changes in weather. However, it is observed that the total withdrawals from the reservoir did follow the weather pattern showing a significant correlation. It is also noteworthy that there was an increased frequency of withdrawals by others exceeding 300 TJ/day, indicating increasing use by others of the deliverability reserved by AGS.

The Board will consider these observations in its views in the balance of this Decision.

During the 2001/2002 storage season, Carbon was not used by AGS, but was entirely under contract to Midstream. However, in consultation with customer representatives, AGS contracted for 11 PJ of storage capability with third parties.

1.3 Confidentiality

The Carbon proceeding involved a procedural first for utilities under the *Alberta Energy and Utilities Board Rules of Practice* (Alberta Regulation 101/2001 to the *Alberta Energy and Utilities Board Act* (Rules of Practice). ATCO Gas had objected to the filing of certain information requested pursuant to information requests filed by the City of Calgary (Calgary). ATCO Gas took the position that some of the requested information was confidential or that it was commercially sensitive. In response to a Motion filed by Calgary on October 30, 2001 to compel disclosure of the requested information, the Board issued a ruling on the Motion dated November 15, 2001, directing that relevant information be filed and indicating that information which ATCO Gas wished to maintain as confidential could be filed pursuant to Rule 12 of the Rules of Practice. On November 27, 2001, ATCO Gas filed a request for confidentiality pursuant

[9] Subject of Decision 2001-110

to Subsection 12(3) of the Rules of Practice. By letter dated November 28, 2001 the Board invited comments on ATCO Gas' request for confidentiality from interested parties.

Subsections 12(1), 12(2), 12(3) and 12(4) of the Rules of Practice state:

> 12(1) Subject to this section, all documents filed in respect of a proceeding must be placed on the public record.
>
> (2) If a party wishes to keep confidential any information in a document, the party may, before filing the document, file a request for confidentiality and serve a copy of the request on the other parties.
>
> (3) The request for confidentiality must
>
> (a) be in writing,
>
> (b) briefly describe
>
> (i) the nature of the information in the document, and
>
> (ii) the reasons for the request, including the specific harm that would result if the document were placed on the public record,
>
> and
>
> (c) indicate whether all or only a part of the document is the subject of the request.
>
> (4) The Board may, with or without a hearing, grant a request for confidentiality on any terms it considers appropriate
>
> (a) if the Board is of the opinion that disclosure of the information could reasonably be expected
>
> (i) to result in undue financial loss or gain to a person directly affected by the proceeding, or
>
> (ii) to harm significantly that person's competitive position,
>
> or
>
> (b) if
>
> (i) the information is personal, financial, commercial, scientific or technical in nature,
>
> (iii) the information has been consistently treated as confidential by a person directly affected by the proceeding, and
>
> (iii) the Board considers that the person's interest in confidentiality outweighs the public interest in the disclosure of the proceeding.

The Board set out matters pertaining to confidentiality in its letter dated December 10, 2001, to interested parties. The Board indicated that considering the purpose and principles of Section 12, ATCO Gas's request for confidentiality and the comments of interveners, it found that ATCO Gas had satisfied the requirements of Subsection 12(4). The Board thus granted ATCO Gas' request for confidentiality with respect to specific information and upon set terms and conditions. As a result, a process ensued that provided for the filing of confidential information responses, evidence, rebuttal evidence and then supplemental information requests and information responses, evidence and argument. In order to be entitled to access or receive designated confidential data, interveners had to request the Board for access, demonstrate a need to access this confidential information and execute a Confidentiality Undertaking in a form prescribed by the Board. Copies of the Board's December 10, 2001 letter together with the various forms of Confidentiality Undertakings and Statutory Declarations relating to the timely return or destruction of such information are attached as Appendix 2 to this Decision. Parties are reminded of their obligations under the Confidentiality Undertaking.

Views of Interested Parties

Calgary

In its comments on ATCO Gas' request for confidentiality, Calgary stated that the onus is on ATCO Gas to prove that the information over which it requests confidentiality is in fact confidential or sufficiently commercially sensitive in nature so as to render it confidential. Calgary noted that ATCO Gas is operating a public utility, and that Carbon is still in its rate base and therefore, the public interest should favour disclosure of all aspects of the operation of Carbon unless proven to be harmful.

Calgary submitted that ATCO Gas provided no evidence that the information was confidential or sufficiently commercially sensitive so as to require it to be confidential beyond merely stating that it should be so. Calgary stated that, in a regulatory context, the public interest must be protected, interveners, and the Board, must be in a position to review, analyze, challenge, or confirm the information filed by ATCO Gas.

Calgary further submitted that where ATCO Gas provided no proof that the information was commercially sensitive to any substantial degree and that there was a significant risk of harm to ATCO Gas the Board must weigh the public interest in disclosure of the information involved. Calgary also stated that the Board should also consider that it is dealing with public utility interests and not "private interests" and should not be persuaded by assertions of ATCO Gas that disclosure will cause financial prejudice, or impair negotiations, without having any details provided by ATCO Gas.

Calgary also submitted that when ATCO Gas refers to financial prejudice that could result from disclosure, ATCO Gas should specify whether it is referring to prejudice to the public interest, to ratepayers, to a "private interest", to ATCO Gas' shareholders through an eventual prudence review, to Midstream as the current operator, or to Midstream (and the ATCO Group) as the intended future operator. In Calgary view, the involvement of affiliates and the failure by ATCO Gas to be specific were reasons for the Board to deny a blanket confidentiality request.

Consumers Group (CG)

The CG agreed with Calgary that ATCO Gas did not provide any adequate basis for confidential treatment of information requested by Calgary. It supported Calgary's position that the requested information was relevant to the Carbon proceeding and should be provided by ATCO Gas.

The CG was concerned with the process proposed for the treatment of confidential information, particularly with respect to the liability implications associated with the requirements for signing confidentiality agreements by parties wishing access to the confidential information. It noted that the process would necessitate the filing of two forms of evidence and submissions and two decision reports (non-confidential and confidential). Further, the process would unduly prejudice the rights of parties who were unable or unwilling to assume potential financial liability associated with signing a confidentiality agreement.

Encana and Unocal

Encana and Unocal did not submit any technical data on the Carbon storage facility and did not obtain access to any material filed on a confidential basis in the hearing. In their final argument they stated that they chose not to burden themselves with confidentiality obligations. In their view Carbon has been around for a long time, it has been a regulated facility and there is a great deal of information respecting the facility which is already in the public domain. According to Encana and Unocal there are no great secrets about Carbon, and given enough time and money to research the public record and analyze it, one could get a fairly accurate picture of the facility.

Views of ATCO Gas

In its request for confidentiality ATCO Gas submitted that it regarded the information in question to be commercially sensitive, and thereby confidential because most of the capacity at Carbon was subject to competition and disclosure of such information would cause it harm relative to its competitors. It noted that similar information pertaining to its competitors was not available in the public domain. ATCO Gas believed that it could not even explain why the information was commercially sensitive without damaging its competitive position in the storage market.

Board Findings

The Board notes the submission of Calgary, supported by the CG, that much of the material for which ATCO Gas requested confidentiality lacked an evidentiary basis for such treatment. The Board is cognizant that a public utility is a for-profit business and that matters of commercial sensitivity can arise which could affect both shareholders and customers negatively if not treated properly. However, having now gone through the confidential and non-confidential portions of the entire proceeding and having more fully considered the nature of the evidence in both portions, the Board recognizes that certain information for which ATCO Gas claimed confidential treatment, particularly reservoir-related technical information, is in fact available on the public record.

In circumstances where the Board has granted confidentiality, only the specifically designated information will be kept confidential, and only when it meets all tests of confidentiality. For example, information in the public domain would not be subject to confidential treatment. This is reflected in the Undertakings signed by parties with access to the confidential information in this case.

The Board is an administrative tribunal whose proceedings and records are ordinarily open to the public and should as far as possible remain so. The Board has considered the concerns of interveners in this case and the potential for unwarranted claims of confidentiality, and believes that confidentiality of information will be the exception, not the rule, in its proceedings going forward. The Board's preference is to consider the issues and make decisions based on an open, non-confidential record wherever possible, in order to maintain the public nature of the Board's determinations and reasons for decision.

In this case the Board has considered the evidence and has determined that for the purposes of this Decision, which is focused on broad high level process directions as requested by ATCO Gas, it is not necessary to address confidential evidence or issues separately in a confidential decision report. The Board believes it can base all determinations necessary for this Decision on the non-confidential record, and has done so.

1.4 Impacts of Decision 2001-75 and Decision 2001-110

Two Decisions recently issued by the Board are directly related to the operations of Carbon. The Board notes that AGS expressed concern in the hearing regarding its attempts to understand the Board's rationale behind these decisions. The Board has summarized the key passages from both decisions below. The Board will consider views of the parties concerning the decisions and reflect its views of those decisions in so far as they apply to this proceeding.

1.4.1 Decision 2001-75, dated October 30, 2001

In this Decision the Board made the following statements:

> The Board is concerned that continued or increased utility gas price hedging programs would seriously affect the potential for retail gas market development, and that such development should be provided a reasonable opportunity to succeed. Therefore, the Board is of the view that utility gas price hedging programs, of any nature, are not seen as necessary at this time.
>
> The Board notes the concerns of marketers that including gas price hedges in the regulated gas portfolio may create difficulties in establishing a level playing field between regulated and competitive gas offerings. The Board is of the view that provision of an un-hedged regulated gas rate eliminates these complications, and will create a reasonable opportunity for the further development of the retail gas market.
>
> The Board notes that there are already physical hedge assets owned by the utilities. In the case of ATCO Gas, there are specific company owned gas production assets and gas storage assets that can, by nature, provide gas price hedging. The treatment of company owned production assets has been addressed by the NCC in its proposal that the costs savings of company owned gas production should be passed to all Core consumers via a credit to base rates, while the gas commodity rate should be charged at the market price for gas. This proposal for company owned production is discussed further in section 5.1 of this Decision.
>
> The Board considers that the use of storage facilities as a price hedging mechanism presents some of the same attributes as company owned production. In both cases the facilities can be described as "legacy assets", assets that have been paid for by all gas consumers in the previously fully regulated market. In both cases, crediting the benefits arising from the facilities directly to the gas commodity rate creates an economic bias towards regulated gas rate offerings, and implies that customers taking competitive gas

supply do not receive any of the benefits from these assets. The Board is of the view that both of these results are undesirable.

Therefore, the Board directs that company storage facility costs and benefits related to gas price stabilization or hedging are to be treated in accordance with the NCC COP Rider proposal. The gas withdrawn from storage will be valued at the current GCRR portfolio cost for inclusion in gas commodity rates.

Until such time as the Carbon facility is removed from regulated service, the Board expects AGS to operate the Carbon storage facility for the benefit of customers, and to allocate the costs and benefits of that facility in the manner described herein to the account of AGS Core customers paying towards the Carbon facility in their rates.[10]

Views of Interested Parties

Calgary

In reply argument Calgary stated:

> The other thing we keep hearing about, sir, is Decision 2001-75 and how it told them to get out of the storage business or how at least disposing of Carbons is in accordance with that. I would strongly encourage you not to subscribe to the view.
>
> During the methodology hearing at Volume 3, pages 165 to 174, when I started to cross-examine the ATCO panel about Carbon, Mr. Smith objected saying Carbon should be dealt with in this hearing. After considerable discussion, you asked me to stay away from Carbon and keep it generic if I could. So my submission to you, sir, is that Carbon has to stand or fall on what goes on in the current proceeding. Decision 2001-75 can't be used to boot strap the case.[11]

CCA

In reply argument the CCA stated:

> Secondly, in respect to Decision 2001-75, AGS neglects to maintain that existing storage, especially Carbon, was provided unique treatment.
>
> We point out that ATCO continually argues about what 2001-75 prohibits them from doing but not what it might allow an LDC to do. The CCA submits it clearly allows for special consideration of Carbon. Further, the ATCO Gas proposal is that Carbon can be easily removed from rate base, almost with no strings attached or no loose ends. The CCA respectfully disagrees. We submit removal is very complex, more so given the unique nature of the Carbon facilities.[12]

[10] Decision 2001-75, pages 55 – 56.
[11] Transcript vol. 12, pages1318-1319
[12] Transcript vol. 12, pages1368-1370

Views of ATCO Gas

In argument AGS stated:

> In Decision 2001-75, the Board recognized the need to support the development of the gas retail market and attempted to remove various perceived impediments to that development.[13]
>
> Second, it directed gas utilities to provide their gas supply from the daily and monthly spot markets. In fact, gas utilities were prohibited from entering into third party storage contracts. Accordingly, the Board has decided that storage for gas utilities in Alberta is not required for gas price management purposes and gas utilities are prohibited from reflecting the financial benefits (or costs) in the gas costs charged to customers. Indeed, from the Board's perspective, the inter-seasonal physical hedging benefits (and costs) offered by storage *per se* appear no longer desirable since it represents an impediment to retail competition.[14]
>
> In Decision 2001-75, the Board ruled that gas price hedging mechanisms, including physical storage, are not appropriate in the provision of regulated gas service. It considered these mechanisms unnecessary in that the *Natural Gas Price Protection Act* would provide adequate price protection to consumers taking regulated gas supply. In dealing with existing storage arrangements, the Board permitted ATCO Gas storage contracts to continue until their expiry on March 31, 2002 and directed that gas storage costs and benefits associated with company-owned storage be treated as a rate rider on base distribution rates until such time as the Carbon facility is removed from regulated service.[15] Due to the rate rider treatment of company-owned storage, Carbon cannot be characterized at present as providing a "physical hedge or peaking supply".[16]
>
> ATCO Gas has been clear that Carbon storage is not required for operational purposes. Therefore, the sole purpose served by holding Carbon storage today is to retain a physical hedge for the purpose of managing gas costs. However, the Board has been clear in Decision 2001-75 that hedging is not approved for utility use.[17]

Board Findings

The Board believes it is clear from the passages repeated here from Decision 2001-75 that the intent of Decision 2001-75 was that impediments facing existing or potential retail gas marketers were to be removed so as to not bias the cost of gas in favor of the regulated supplier, e.g., ATCO Gas, in order to enhance the development of a competitive retail (commodity) market for natural gas. Where storage was being used as a physical hedge, the Board determined that the economic impact of storage should be removed as a price signal by recovering it through a rider to the base rates, so that there would be no economic effect of storage on regulated commodity supply costs included with the gas cost recovery rate (GCRR).

13 Page 2 of 107
14 Ibid.
15 Decision 2001-75 Section 4.2.2.
16 Pages 15 and 16 of 107
17 Page 55 of 107

The Board believes it is clear that AGPL was expected to continue to provide AGS's customers with the benefits of a physical hedge so long as it continued to own Carbon. This would essentially mean buying and injecting the gas in the summer, when prices are usually the lowest, and withdrawing in the winter, when prices tend to be the highest. Although the Board stated that it did not believe it was necessary for the gas utility to provide financial hedges of the commodity price to customers, there will always be an inherent price component to a physical hedge. In some respects it is artificial to separate the physical and financial aspects of storing gas. Nonetheless, the Board believes that Decision 2001-75 recognized that Carbon has value in providing a physical hedge, that it would in most years provide a corresponding financial benefit to such a hedge, that Carbon could be retained in the utility as a 'legacy asset' and that retail market development could benefit by removing the impact of this physical and related financial hedge from the competitive commodity market.

1.4.2 Decision 2001-110, dated December 12, 2001

In this Decision the Board made the following statements:

> Storage has provided managers of gas supplies with a physical hedge and a peaking supply for many years, and the Board expects this principle of gas portfolio management to continue as long as utilities own storage. The Board also notes that there are a range of load factors and storage services available to managers of gas supplies. In particular, the Board in Decision 2001-75, provided for the continued use of Carbon as a physical hedge and a peaking supply for as long as it is a used and useful rate base asset.[18]
>
> The Board also expects AGS to be more diligent in the future in achieving cost savings for customers and to investigate methodologies, such as the one presented by [Calgary's witness] Mr. VanderSchee, that will assist it in making decisions when managing the withdrawals from Carbon for the customers benefit.[19]

Views of ATCO Gas

During the hearing in response to a question regarding the statement "In particular, the Board in Decision 2001-75 provided for the continued use of Carbon as a physical hedge and a peaking supply for as long as it is a used and useful rate base asset," AGS answered:

> We may be missing something, but when we go back and look at decision 75, we don't see that reference in that decision and, as I described, I think this statement is in complete conflict with the principle that we offer monthly gas pricing. And if you go to the statement in decision 75 that said we should set up a rider, a storage rider for Carbon, then it's not there to provide a physical hedge or a peaking supply because it's not in the -- it's not in the safety net. It's simply a way to capture benefits.[20]

18 Decision 2001-110, page 27
19 Ibid, page 30
20 Transcript vol. 7, page 666

Board Findings

The Board believes it is clear from the passages repeated here from Decision 2001-110 that AGS should operate Carbon in a manner so as to provide benefits to AGS's customers, such as using lower cost stored gas to offset the cost of higher priced spot market gas.

The Board considered that AGS could have benefited from the assistance of a decision enhancing tool as described in evidence presented by Calgary[21], which would have provided guidance to withdraw or buy gas on a daily ex-ante basis. The Board understood the model (or method) to use daily prices, inventory levels, remaining days to withdraw, withdrawal rates and future prices as inputs to calculate a positive or negative result that would be used to decide to buy or withdraw gas from storage. The Board expected that gas could be sold to customers as part of AGS's total gas supply when withdrawn. This method of using Carbon would not be characterized by commodity trading or the use of financial hedging.

In the absence of a decision tool similar to the aforementioned, the Board considered AGS's customers would have benefited if AGS had used the deliverability it had at its disposal to withdraw gas when gas prices were spiking.

1.5 Public Hearing

The Board held a public hearing with respect to the Application in Calgary, Alberta for nine days, commencing on March 11, 2002, before Mr. B. T. McManus, Q.C., Presiding Member; Mr. M .J. Bruni, Q.C., Acting Member; and Ms. C. Dahl Rees, Acting Member. Oral argument was subsequently heard on April 18, 2002. During the course of the hearing when confidential issues were being addressed, the Board required that the hearing room be closed to the general public and that only those individuals who had signed the mandatory Undertakings for Confidentiality could be present. Those who appeared at the hearing and abbreviations used are set out in Appendix 1.

2 DETAILS OF THE APPLICATION

ATCO Gas requested the Board to:

(a) approve the withdrawal of Carbon from regulated service and rates; and
(b) establish a process by which the fair market value (FMV) of Carbon could be determined so that it could be transferred to Midstream.

It proposed that a withdrawal be addressed in three steps:

- First, included as a part of the Application and as a consequence of approval of withdrawal from regulation, ATCO Gas sought approval of a process for determining the FMV of Carbon.
- Second, subsequent to receiving the applied for approvals, ATCO Gas would then implement the process to determine the FMV of Carbon.
- Third, in an ensuing application, ATCO Gas would request approval of an allocation between it and customers of the proceeds paid by Midstream.

[21] Decision 2001-110, page 20

ATCO Gas submitted that Carbon was no longer required for utility service. It stated that various parties have questioned its operation of Carbon and have appeared to assert that Carbon should be subject to competitive forces, either through unbundling or through direct competition for the right to provide storage needs related to the Deferred Gas Account. It further stated that it has only included the original costs of the assets required to operate the storage business in determining its rates. It further submitted that the only matter to be before the Board regarding the disposition of Carbon would be an assessment of potential harm done to customers as a result of its removal from regulation and to accordingly determine the amount of compensation due to customers. ATCO Gas added that base gas was intrinsic to the operations of Carbon. In this respect, it stated that since no costs related to the value of base gas have been recovered from customers, there was no basis to conclude that customers would have any entitlement to the base gas.

Attached to AGS's application letter of July 18, 2001 were studies prepared by RiskAdvisory and The Ziff Energy Group, both of which had been filed by ATCO Gas in previous applications. The RiskAdvisory report, dated January 14, 2000, dealt with a "Discussion of Issues Surrounding Physical Storage Positions". The Ziff Energy Group report, dated February 2000, provided comments on gas supply alternatives, a storage recommendation for the period April 2000 to March 2001, and a recommended appropriate level of storage for AGS to use in its gas supply portfolio over the following five years. Included with its September 28, 2001 letter was a report of the same date prepared by Michael J. Harris, Ph.D., of Econ One Research, Inc., entitled "Re: A Competitive Evaluation of the Alberta Storage Market".

3 ISSUES

Pursuant to responses received during the interrogatory process, the Board determined that it, along with the interested parties that had registered to participate in the Carbon proceeding, would benefit from the preparation of an issues list to provide for a more focused and efficient hearing process. In the absence of an actual transaction and a FMV determination for its review, the Board was concerned that it did not have sufficient information to render a decision on the ability of AGPL to remove Carbon from regulated service. In a preliminary issues list e-mailed to interested parties on November 5, 2001, the Board questioned: (1) if approval for an actual asset transfer was not being sought, should a public hearing proceed, and (2) if the hearing was only to determine a FMV process and appropriate criteria to be used in applying the no-harm test in a future hearing, what level of historical, operational and financial detail was required to be provided in this hearing to the Board and interested parties. After considering comments received from interested parties the Board decided to continue with the hearing.

In a letter dated November 9, 2001 the Board emailed a final, non-exhaustive issues list to interested parties, in which it set out particular issues that would be considered during the Carbon hearing. The purpose of the hearing was for the determination of the following matters:

1. Are the Storage Facilities used or required to be used?
2. Can the Storage Facilities and the related Producing Properties be removed from regulated service?
3. What assets make up the Storage Facilities and the Producing Properties?

4. If the Storage Facilities and the Producing Properties can be removed from regulated service, what should the process be to determine their FMV?
5. If the Storage Facilities and the Producing Properties can be removed from regulated service and a sale would satisfy the "No Harm Test", is a closed process transfer to an affiliate appropriate?
6. What are the appropriate "No Harm Test" criteria to assess a potential future application to approve the sale and transfer of the Storage Facilities and the Producing Properties?
7. Finalization of outstanding matters brought forward from the GRA and Affiliate proceedings.

The Board's issues list of November 9, 2002 provided additional guidance regarding each of these matters, and is attached hereto as Appendix 3.

3.1 Used or Required to be Used

Views of Interested Parties

Calgary

The gist of Calgary's position could be observed in the following statement from its argument:

> As noted in Calgary's evidence, and many times in cross-examination, Calgary's position has been, as long as assets are used to provide safe and reliable services at lowest reasonable costs, they should be retained by the utility because they are used and useful. This is an economic decision, and as pointed out by Mr. Johnson there are a number of assets included in rate base that the ownership of which is related to an economic decision, since most of the services can either be provided through leases or from third parties. [22]

Calgary also stated that:

> …regulatory theory and practice supports the proposition that where a rate base asset has been built up at ratepayer risk and that asset can be used in a way to reduce costs, then the asset should be retained by the utility. [23]

Calgary submitted that its economic analysis provided in its evidence, and particularly Attachment 1[24] to the Written Evidence of the City of Calgary, and the Energy Objective ("EO") report "Gas Storage and the Carbon Storage Facility - A Determination of Operational and Economic Value to the Customer,"[25] shows that the retention of Carbon is in the ratepayer's best interest and therefore the facilities are used and useful.

22 Argument of Calgary, pages 12 and 13 of 43
23 Transcript vol. 12 pages 1317, 1319-1324
24 "Benefits and Value to Ratepayers" using analyses developed by Calgary for revenue requirement for the Carbon facility for the years 1999–2002 based upon consistent databases; revenue requirement for the year 2002 based upon the AGS response to CAL-AG.10(c); and a calculated a value for a number of benefits or values that ratepayers should expect to receive based upon historical Carbon operating parameters and the findings of the Board in Decision 2001-110.
25 Exhibits 89 and 90B

Calgary's evidence also included a report of Sproule Associates Limited ("Sproule") titled "Methodology for the Determination of Value for Carbon Storage and Production Assets (as of January 1, 2002)" that dealt with the reservoir assessment and preliminary FMV and "No Harm" assessment of Carbon. Calgary submitted that the reservoir assessment concluded that Carbon is a viable storage operation and that the continued utilization of Carbon as a storage operation is producing a positive benefit for ratepayers.

Calgary argued that Carbon is required to be used in order to provide the maximum benefit to ratepayers. It believed that there are no alternative arrangements that could be utilized that would support removing Carbon from regulated service. Calgary used a "rent or buy" comparison, noting that the rental of an asset does not give the same flexibility and opportunities as owning the asset. Calgary also submitted that there were limitations to the storage arrangements used by ATCO Gas in the 2001/2002 winter period that were not present when CWNG operated Carbon, nor were such limitations applicable when CWNG used Carbon to provide maximum operating flexibility, peak day requirements and gas price savings.

In its argument Calgary submitted that ATCO Gas developed and presented "myths" with respect to Carbon. Calgary agreed that the Alberta gas market could provide gas supply for ATCO Gas and that Carbon was not strictly required for operational purposes. However, Calgary submitted that the use of Carbon involves an economic decision regarding a utility rate base asset to determine if the cost/benefit associated with the change in operations weighs in favor of the non-utilization of Carbon as a utility asset. Calgary noted other advantages of storage, including:

- the ability to change nominations and deliveries on a minute to minute basis, or within a ten or fifteen minute time frame;
- benefits related to the cost of gas and the hedging capabilities, thereby reducing price volatility and capturing seasonal and daily differentials; and
- the avoidance of liquidity premiums.

CG

The CG submitted that in effect, there are two distinct parts to the Board's determination of whether a particular asset is no longer "used or required to be used" for utility service. The first test is to determine whether there are acceptable physical alternatives and, if that test is met, the second test is whether removal from service will financially harm customers. If the answer is positive (i.e. harm will occur) then the assets cannot be removed from utility service without adequate compensation to customers.

The CG noted that witnesses for both ATCO Gas and interveners agreed that alternative arrangements for storage are available. However, it stated that there is uncertainty whether such alternatives would provide ATCO Gas with the same flexibility and, accordingly, the same opportunity to maximize future value to customers through the optimal use of Carbon. Retention of Carbon as a rate base asset provides opportunity to maximize flexibility.[26]

The CG concluded that although the Carbon storage facilities are currently being used and provide benefit to customers, there is a question as to their ongoing benefit and unanswered questions remain about the optimization of the use of those facilities.

[26] Transcript vol. 12, pages 1327-1328

The CG submitted that AGS operated through the 2001/2002 winter season without Carbon, and that it is generally acknowledged that Carbon was not required for operational purposes (i.e. reliability of service) in that winter season. However, the CG also submitted that is not to suggest that it has not in the past or could not in the future provide financial benefits to AGS customers. The CG concluded that although Carbon is currently being used, ostensibly for the benefit of customers, it is not "required to be used" in the physical sense of providing operational storage. Nevertheless, the CG suggests Carbon will continue to be "used" until such time as the Board approves a sale and concurrently determines the required "no-harm" compensation calculated based on the loss of future benefits which would have flowed to customers from continued operation of Carbon in whatever manner is most beneficial. The CG was of the view that this question cannot be addressed in any comprehensive way based on the evidence adduced. The CG stated that the Board cannot overlook the fact that AGS has expressed its unwillingness to continue management of Carbon. However, the CG was of the opinion that these facilities can be disposed of if and when a purchaser becomes available who is prepared to pay an amount at least equal to the required "no-harm" compensation.

The CG argued that neither the initial application nor the subsequent evidence of September 28, 2001 appeared to contemplate an approval by the Board pursuant to the Gas Utilities Act, R.S.A. 2000, cG-5 (GU Act). Therefore the CG submitted that the Board need do nothing more than determine whether the facilities are required by AGS for utility operational purposes and, if not, to indicate that an application for sale pursuant to the GU Act would be considered favorably subject to customers receiving the required "no-harm" compensation.

The CG argued that it is a given that Carbon has value as a storage facility – the challenge is, however, to determine how best to determine this component of its value. The CG submitted that all of the alternatives identified for Carbon are reasonable to consider. These alternatives should not be considered solely in the context of whether Carbon should remain in utility service. Rather, these alternatives should be evaluated in terms of the future value to customers and the resulting harm to customers in the event the facilities were transferred or sold and no longer available to customers. The CG concluded that it should be obvious that if the proceeds available to customers are not equal to this future alternative use that produces the optimum value for customers, then the storage facility should remain in "use" as a utility asset.

The CG asserted that the provision of regulated utility service not only should be secure and reliable, but it should be done at a reasonable cost. If an asset was in utility service and if continuing use of that asset in changed circumstances still contributed to the provision of service at the lowest reasonable cost, then that asset could reasonably remain under utility regulation, particularly if there was no demonstrated alternative way of obtaining that service for customers at a similar reasonable cost.

CCA

The CCA submitted that Carbon, while being very unique, was and would continue to remain used and useful and should continue to remain as a rate based asset, from which ATCO Gas' customers should continue to receive benefits. The CCA did not consider that the availability of a competitive alternative was sufficient to allow an asset to be removed from rate base, particularly over the objections of customers. It noted that alternatives can exist for all utility rate base assets and that a standard regulatory practice was to require a utility to analyze several competing alternatives for a utility rate base addition. The option that was often deemed appropriate for additions to rate base was based on the requirement of a lowest cost to customers from among all similar offerings. The CCA submitted that an example was the salt cavern storage facilities owned by AGPL. This facility was included in rate base even though it was generally acknowledged it could be replaced with more expensive transmission lines.[27]

The CCA was concerned that ATCO Gas had structured its operations to make it appear that Carbon was no longer used for operational services, noting that ATCO Gas, or then CWNG:

- removed the operational employees associated with Carbon storage facility from the utility to a non-regulated affiliate;
- removed the benefit of operational use of storage from utility services and gave the benefit of this operational use to a non-regulated affiliate; and
- removed the seasonal use of Carbon from customers and replaced it with third-party contracts.

The CCA was further concerned that the sale to Midstream without some type of reversion feature would place customers in a very risky position if the retail natural gas market did not develop. It stated that Carbon should be considered a legacy asset, and submitted that it was unlikely that Carbon could in the future ever be replaced with facilities of a similar scope or scale of benefits. It further submitted that these benefits included:

- base gas at low cost because of its vintage nature;
- no royalty payments on the base gas;
- the geographic location of the Carbon storage facilities being uniquely located close to Calgary, the major load center of the AGS system;
- Carbon's being dually connected to the NGTL and ATCO Pipelines transmission systems; and
- company-owned or third-party physical hedges not having the same counter party credit risk as financial hedges.[28]

The CCA argued that a use of storage beyond operational concerns was for hedging purposes, which refers to a risk management tool that minimizes the risk of exposure to gas price fluctuations. It also argued that, as ATCO Gas had not determined the risk preferences of customers, and as its residential customers were risk adverse and desired low and stable gas prices, ATCO Gas should be prevented from moving Carbon from rate base.

The CCA considered that utilization of the intra-Alberta gas market for peaking would significantly increase gas price volatility as opposed to the use of storage for peaking purposes. The CCA noted that historically, if the Carbon storage facility failed in providing peaking to customers, the intra-Alberta market was available for this purpose. The CCA considered that Carbon provided ongoing benefits to customers and could be used to shield customers from volatile gas prices and changes in the market place.

[27] Transcript vol. 12, pages 1335-1336
[28] Ibid, page 1337

Encana and Unocal

Encana and Unocal believed that Carbon, in the current environment, was no longer used or required to be used to provide utility service to ATCO Gas' customers. They stated that events of the 2001/2002 winter period indicate that it was not required for operational purposes relating to the operation of the ATCO Gas system and that in the future, should ATCO Gas have any need for storage, these needs could be satisfied by ATCO Gas contracting for storage with third-party storage operators.[29]

Views of ATCO Gas

In its submission ATCO Gas provided evidence in an attempt to prove that Carbon was no longer "used or required to be used". ATCO Gas submitted that the gas and storage markets in Alberta were sufficiently mature, deep and liquid to handle all requirements the utility might have, including peak demand hours and "just take it" flexibility. For the 2001/2002 storage year ATCO Gas stated that the market had provided all its requirements by contract without the need to call on Carbon directly.

In reply argument ATCO Gas stated that the past benefit the customers had enjoyed was the utility use of storage, which focused on safe and reliable distribution service. On the other hand, the future benefit to a different operator would be a very different non-utility function, one significantly riskier and only perhaps more rewarding than a utility operation. In reply, ATCO Gas' view was that for ratepayers, the benefit in removing a utility operation or undertaking like Carbon from regulation was to reduce rates and to eliminate the risk associated with the ownership and operation of storage, while ensuring the continuation of safe and reliable service.

ATCO Gas argued that integral to the determination of whether Carbon should be withdrawn from utility service was the need to determine whether Carbon continued to be used and useful, and that, in ATCO Gas' submission, centered around the continued need for its use as part of the basic monopoly service. It added that throughout its history, it has consistently maintained that the purpose of including the Carbon storage facility as part of its regulated distribution system was to provide operational flexibility, both in meeting physical peak day requirements and in addressing day to day fluctuations in load. However with the dramatic evolution of the natural gas market, the operational necessity for Carbon diminished over time. ATCO Gas stated that at present and for the past number of years the development of both a highly competitive storage market and a sophisticated gas market have removed the need for Carbon storage altogether. ATCO Gas noted that it had advised in 1999 that the gas market had already evolved to the point where Carbon was no longer required to provide operational flexibility.

ATCO Gas submitted that the Board in Decision 2001-75 decided that storage for gas utilities in Alberta was not required for gas price management purposes, that gas utilities were prohibited from reflecting the financial benefits or costs in the gas costs charged to customers, and that inter-seasonal physical hedging benefits and costs offered by storage per se appeared no longer desirable since they represented an impediment to retail competition. ATCO Gas argued that in the storage year April 1, 2001 to March 31, 2002 it demonstrated that Carbon was no longer required for monopoly utility service, noting that it did not utilize storage at Carbon and customers did not see any adverse consequences from an operational perspective or from a

[29] Ibid, pages 1345-1346

financial perspective. In that year ATCO Gas noted that conditions included fluctuating temperatures, peak use requirements and gas prices which were higher in the summer period than in the winter period. ATCO Gas further submitted that if its recommendation not to use contract storage in the 2001/2002 year had been followed by the Board and interveners, customers would have saved millions of dollars while still receiving safe, reliable utility service.

ATCO Gas submitted that the availability of storage in the competitive market eliminated the need for Carbon. It contended that whatever level of storage service which interveners and the Board thought necessary could be provided on the open market through competitive bids, at a cost less than the cost of owning and operating Carbon. It questioned why competition should be proxied through continued regulation of Carbon when competition clearly existed.

ATCO Gas noted that certain interveners appeared to be defining “used and useful” to mean that as long as an asset can provide residual financial benefits to customers, it was “used and useful” in the provision of safe, reliable utility service. It contended that this type of argument was flawed and that it represented a move from cost based regulation to opportunity cost based regulation of Carbon, which interveners have acknowledged not to be required for the provision of safe and reliable gas distribution service. ATCO Gas referred to the corollary, and asked that for years for which there were net costs attached to the storage business, not benefits, would the Board determine that Carbon was not “used and useful” and therefore ought not to be included in rate base?

ATCO Gas stated that Calgary’s position that the use of Carbon had always been based on economics was irrelevant and misleading. It argued that Calgary transformed a truism into a tautology - if Carbon was in rate base and it had value it must remain in rate base, being Calgary's justification for requiring utilities to operate utility assets no longer required for monopoly utility service in a range of different business ventures.

ATCO Gas stated in argument that it had demonstrated that the operational flexibility provided by Carbon in the past was no longer required and that it could provide safe, reliable monopoly utility distribution and supply service, without owning and operating storage at Carbon. ATCO Gas concluded that it thus demonstrated that Carbon was no longer used and useful in the provision of monopoly utility service.

Board Findings

As previously noted in its correspondence of November 9, 2001, the Board was concerned with the lack of clarity in the Application, particularly because of the hypothetical nature of ATCO Gas’ requests. The Board notes that interveners shared this concern. Calgary, in its correspondence to the Board, dated November 7, 2001, expressed its concern not only about the lack of clarity in the Application, but also about the uncertain relief being sought by ATCO Gas and a lack of evidence from ATCO Gas to support an application to withdraw Carbon from utility service. The Board agrees with the CG that the Application does not appear to contemplate an approval by the Board to sell or otherwise dispose of utility property outside the ordinary course of business pursuant to the GU Act. The Board further agrees with the CG that in the circumstances, and in terms of setting the parameters of a process for ATCO Gas to move forward, the Board at this stage should consider and determine, if possible, whether the facilities are used or required to be used by AGS for utility purposes. Further, the Board considers it necessary to address the requirement in any sale or disposition process that the customers receive "no-harm" compensation.

Subsection 37(1) of the GU Act, states:

> In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta …

Similar wording exists in Subsection 90(1) of the *Public Utilities Board Act, R.S.A. 2000, cP-45* (PUB Act). In Decision E76110, dated September 14, 1976, the Board in dealing with its review of the rate base for Northwestern Utilities Limited, stated "The determination of what property of the owner is 'used or required to be used in his service to the public within Alberta' … and which will be carried in the rate base is a question of fact to be decided by the Board in each case based on the evidence and circumstances pertaining to each case."[30] The Board went on to state "Depending on the facts in a particular case, property that is not immediately and/or fully used may none the less be property that is 'used or required to be used in service to the public within Alberta' and therefore properly form part of the rate base."[31]

The phrase "used or required to be used to provide service to the public within Alberta" as found within section 82(1) [now sec. 90(1) RSA 2000, c. P-45] of the PUB Act has been considered by the Alberta Court of Appeal.[32] The Court of Appeal stated:

> The phrase "used or required to be used" is well known in the field of utility regulation.
>
> Much of the argument before us was directed to a consideration of whether that expression is conjunctive or disjunctive. More significantly, it was directed to the proposition that if an asset is in fact "used" then any need that it be "required" disappears.
>
> The case-law, and common sense, dictate that there may be assets included in a rate base which are not in actual use such as stand-by equipment, and the phrase is often used disjunctively to recognize that situation. On the other hand, mere use is not sufficient to burden consumers with the cost. Clearly the consumer need not bear all the costs of an asset which is used if, for example, it reflects an imprudent expenditure. Assets unnecessarily used are not, simply by use, put into the rate base. Without putting too fine a point on interpretation we conclude that even if an object is used it must also be required. If it is not in actual use, it must none the less be required. The expression may be construed both disjunctively and conjunctively. We are supported in that view by American case-law as well as by a consideration of the object of utility rate regulation.
>
> There are many decisions in the United States dealing with this terminology and a similar expression "used and useful". The phrase "used and useful" has come to

[30] Decision E76110, page 23-24.
[31] Ibid page 24-25.
[32] *Alberta Power Ltd. v. Alberta Public Utilities Board* 66 D.L.R. (4th) 286 (leave to appeal to the Supreme Court of Canada refused).

> import a measure of flexibility in determining when assets may be brought into the rate base. "Used and useful" may be viewed as both conjunctive and disjunctive …
>
> Once the interpretation is determined, whether a particular item is to be brought within the rate basis is essentially a question for the judgment of the board which does not involve a question of jurisdiction or law …[33]

The case before the Court of Appeal dealt with the propriety of assets being allowed into rate base, thereby supporting utility earnings. In addition, at times it can be a regulator's duty to determine if a utility property is no longer necessary or useful in the performance of the utility's duties to the public and whether it therefore should be removed from the earning base. In the case of Carbon, the Board must consider the relevance of the "used or required to be used" test as it relates to the evolution of the gas market in Alberta and whether or not the current and forecast liquidity of this market, including the competitiveness of the related gas storage market, displaces the ongoing need for Carbon. In this regard the Board notes the view of the Alberta Court of Appeal that an asset, which is not being used at a point in time, can still be required to be used and therefore properly included in the rate base.

In considering the "used or required to be used" test and comparing it with the "used and useful" test, the Board finds it helpful that the Alberta Court of Appeal appears to make little distinction between them. There is broad North American jurisprudence on the "used and useful" test, which both the Board and interveners have considered over the years. This test is frequently imposed by a regulatory authority, pursuant to its governing legislation, in determining whether or not a property will render service to or for the public in terms of present and expected demand and at a reasonable cost, and whether such property therefore should be included in rate base. The term "used and useful" does not only refer to needed capacity, but also reflect that the property in question is economically desirable. As indicated above, "used and useful" is a flexible concept, which allows regulators to consider all the facts of a matter before them before making a determination in the particular circumstances.

In summary, the Board believes that both the "used or required to be used" test and the "used and useful" test provide the Board with a high degree of flexibility in determining whether assets should appropriately be in rate base, and the Board believes the jurisprudence overall supports such flexibility as a necessary element to allow regulatory bodies to balance the interests of utility investors and customers.

In applying the "used or required to be used" and "used and useful" tests specifically to Carbon in terms of its past and present use, the Board notes that in Decision 2001-110, it was stated:

> Storage has provided managers of gas supplies with a physical hedge and a peaking supply for many years, and the Board expects this principle of gas portfolio management to continue as long as utilities own storage. The Board also notes that there are a range of load factors and storage services available to managers of gas supplies. In particular, the Board in Decision 2001-75, provided for the continued use of Carbon as a physical hedge and a peaking supply for as long as it is a used and useful rate base asset.[34]

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[33] Ibid, 303.
[34] Decision 2001-110, page 27

The Board also notes the references in the evidence that storage generally provided a benefit in 6 out of 10 years in the historical period from 1990/1991 to 1999/2000.[35]

The Board considers that the continued use of Carbon by ATCO Gas could be useful, especially while the retail market is under development. The Board notes that only one Intervener group at the hearing believed that the asset could be sold ("…if and when a purchaser becomes available who is prepared to pay an amount at least equal to the required 'no-harm' compensation")[36], on the basis of AGS not having used it for the storage year 2001/2002.

Although ATCO Gas obtained short-term storage agreements for the 2001/2002 winter period, which ATCO Gas submitted provided for storage capacity at an approximate rate of $0.17/GJ, the Board is concerned about the lack of information with which to assess and compare such future contract storage costs with the operating costs associated with Carbon.

Further, the Board shares the more general concern of the CCA that the manner in which ATCO Gas has structured its operations may make it appear that Carbon is no longer used for operational services and no longer needed. Notwithstanding how ATCO Gas operated Carbon during the 2001/2002 winter period, and the acknowledgement by the CG that ATCO Gas did not appear to need Carbon in the 2001/2002 winter period, the Board believes it has received insufficient evidence overall to allow it to confidently determine that the asset would not be used or required to be used in future. This is so given the Board's current understanding of historic and present technical and operational aspects of available storage facilities, including storage capacity, capacity to deliver, physical operations, interconnections with other pipeline systems, exchange and swap capabilities, peaking flexibility, and operating and maintenance costs as they affect the provision of service in the Calgary region. Comparison of information provided by ATCO Gas on degree-days and withdrawals[37], as discussed in Section 1.2 of this Decision, reveals a close correlation, indicating that Carbon has been operated in winter seasons to serve the AGS market and suggesting that Carbon is required to meet the temperature sensitive demands of the Calgary environs. The Board considers that it is clear from the foregoing historical observations that Carbon has been operated in the winter season to service the AGS market and especially in a fashion that correlates to the temperature increases and decreases and, at times, others have utilized a portion of the deliverability that AGS had reserved for its own use.

Overall, the Board considers that at present there is insufficient economic and financial evidence with which to determine that a withdrawal of Carbon from regulated service would in all events not harm AGS's customers. The Board considers that there is evidence to indicate that Carbon continues to be a used and useful regulated asset, notwithstanding there are alternatives to its use available. The status quo operation of Carbon on a prudent basis would appear to remain appropriate at the present time.

This is not to say that the Board would dismiss a future application by ATCO Gas to dispose of Carbon. The Board believes there is some uncertainty as to the degree of usefulness of Carbon. Therefore, the Board would be willing to consider a sale of the assets if certain conditions can be

[35] Exhibit 3, Appendix A, Ziff Energy Group, ATCO Gas (South) Storage Study, page 19.
[36] CG Argument, page 7
[37] Cal-AG.18 and Cal-AG.19

met, the foremost of which is keeping the customers harmless by establishing a no-harm value. The Board would apply the no-harm principle to any future application by ATCO Gas to dispose of Carbon and would require ATCO Gas to demonstrate that the no-harm test would be met in accordance with the conditions discussed later in this Decision.

3.2 Removal of Assets from Regulated Service

Views of Interested Parties

Calgary

Calgary stated in argument that it was not advocating the disposition of Carbon. It was Calgary's opinion that if Carbon was removed from regulatory oversight the core market customer was exposed to a storage market that may not be truly competitive. Calgary stated that ownership and leasing did not provide the same advantages; that a lessee is limited to contractual arrangements, which would generally preclude intra-day changes of nominations and not allow AGS to circumvent the NGTL four-hour rule.[38] Calgary's view was that the Carbon cannot be replicated by a better alternative that is not owned by AGS.

CG

The CG noted in argument that AGS had submitted the following in its evidence of September 28, 2001:

> "That application [of July 18, 2001] requested two things: that the Board [1] approve the withdrawal of the Carbon storage facility from regulated service and rates; and that the Board [2] establish a process by which the FMV of the Carbon storage facility could be determined so that the facility could be transferred to ATCO Midstream."[39]

The CG maintained that the initial application had not requested the Board to approve the removal of these facilities from regulated service; however, the CG assumed that the more recent reference fully described AGS's position.

AGS's request for the removal of Carbon from regulated service caused concern for the CG since approval would, by definition, eliminate the regulatory oversight exercised by the Board regarding rate base assets and the ability of interveners to question the prudence of management. The CG's view was also that it begged the question as to the legal meaning and effect of withdrawing assets from regulated service. For example, the Application differed from the Viking transfer proceeding in that it was not an application to sell, lease, mortgage or otherwise dispose of or encumber its property outside the ordinary course of business, pursuant to Section 26(2)(d) of the GU Act.

The CG pointed out that the aforementioned section of the GU Act is virtually identical in terms to Section 101(2)(d) of the PUB Act. In Decision 2000-41,[40] the Board held that, in approving such a sale, it must be satisfied that the proposed transaction will either not harm customers or,

38 1996 Winter GCRR October 23, 1996 transcript page 60.
39 Evidence, Exhibit #15, page 1
40 TransAlta Utilities Corporation, Sale of Distribution Business (July 5, 2000).

on balance, leave them at least no worse off than before the transaction in terms of financial impact and reliability of service.

CCA

The CCA stated its first preference was for AGS to keep Carbon; however keeping the facilities would require a number of operational changes to ensure that the greatest economic value was derived for customers. The CCA was also concerned that an outright sale of the property would expose customers to change in the marketplace in the future. Blow down or the production of gas, which AGS considered to be base gas, may be in the best interests of customers if the net present value of the blown down natural gas was greater than the value of the third party sales. The CCA argued it could not distinguish between these two alternatives, because no third party bids had been received or were known.

Views of ATCO Gas

ATCO Gas suggested that the Board ought not to get lost in the details surrounding Carbon, but rather should elevate its gaze, look at the market as a whole and recognize that there is a vibrant, competitive storage market functioning in the province and that it does not require regulation. ATCO Gas stated that there was tremendous liquidity in this market, providing an array of new services which constantly adapt to continued market change and market requirements, citing the after hours' market as a good example. According to ATCO Gas, the Board should recognize the fact that in the future, should marketers or retailers require storage service, it can be obtained freely at competitive rates, and competitive rates means fair and reasonable rates. ATCO Gas stated that through regulation the Board was able to proxy that process.

Under the circumstances, ATCO Gas believed it was obvious that Carbon was not required to be used to provide safe and reliable utility service at fair and reasonable rates.

Board Findings

The Board agrees with the CG that the Board does not have before it an application to sell, lease, mortgage or otherwise dispose of or encumber its property outside the ordinary course of business, in accordance with section 26(2)(d) of the GU Act. The Application by AGPL is for a process to determine a value for a transfer to Midstream. The Board would expect that if ATCO Gas in future decides to enter into a transaction to dispose of Carbon in a way that meets the no-harm requirements of the Board, the next step would be an application for Board approval pursuant to section 26(2)(d) of the GU Act.

3.3 Properties Included in the Carbon Storage and Production Facilities

Issue 2 of the Board’s Issues List raised the question as to what assets, permits, rights and obligations should be considered in the context of a disposition of the storage facility and the producing properties. In addition, section 3.1 of the Board’s Issues List raised the issue of the potential for incursions and interactions between the storage reservoir and the producing properties. Various parties dealt with these issues in the hearing. For purposes of this Decision the Board will address these items in a summary fashion.

Board Findings

Under consideration here is the matter of acreage protection for the storage reservoir and the appropriate packaging of buffer lands with the storage reservoir lands to maximize value of the storage reservoir on a sale. It is a given that a prudent operator of a storage reservoir would retain under its ownership or control a buffer land position around the storage field in order to guard against the risk of geological uncertainty. ATCO Gas indicated as much in BR-AG.14 and the Board agrees.

In addition to the risk of geological uncertainty, the Board notes that the issue of migration or drainage of the storage reservoir by ATCO Gas non-Carbon Unit wells to the south and east of the Unit was raised on the non-confidential record by the City of Calgary through the expert reports of Sproule, and was also addressed to a lesser degree by ATCO Gas' expert McDaniel on the non-confidential record.

The Board considers that if ATCO Gas intended to reduce the value of the storage reservoir on a sale, one method it might use would be to package the storage reservoir lands with inadequate buffer protection and sell any producing properties which might have drainage potential separately to a different purchaser than the storage reservoir purchaser. The Board does not believe this is in any way the intention of ATCO Gas. Its intention would appear to be quite the contrary given ATCO Gas' statement of position in BR-AG.14.

The Board believes that for present purposes the issue of packaging may be appropriately dealt with in general terms. The Board would expect to see a fully defensible land packaging proposal from ATCO Gas on any future application to sell or otherwise dispose of Carbon. This proposal would involve transfer of ownership or control of potential migration or drainage lands or wells to the purchaser of the storage reservoir.

3.4 Process to Determine the Value of Carbon

Transfer pricing is generally an issue in transactions involving a public utility and its unregulated affiliates. In Decision 2002-069 issued in respect of the Affiliate Proceeding, the Board found that FMV is the appropriate standard for asset transfers between a utility and a non-regulated affiliate, provided customers are not harmed and the sale is the prudent course of action. The parties in this proceeding appear to have adopted the FMV standard for the sale of Carbon without question. Consequently the focus in this hearing was on the appropriate process to determine FMV.

Views of Interested Parties

Calgary

Calgary's evidence was that the market value for Carbon could not be determined in a closed sale procedure as proposed by AGPL. The procedure proposed by AGPL precluded the opportunity that "special purchasers" might perceive more value to the field than might be calculated by an analyst. Further, Calgary was concerned that there are few, if any, consultants with the necessary expertise to determine an appropriate value.

Calgary believed that should the Carbon assets be removed from utility service the only way to ensure that the customer's interest was protected was through a tendering process; that this would ensure that all value perceived in the market place was realized and that value to the customer was optimized. Calgary stated that parties should also be able to bid on the cushion gas and associated company owned production as a separate package with another package including producing properties in the non-Mannville zones.

With respect to AGPL's concern about providing sensitive information to competing storage operators in an open bid process, Calgary did not believe it desirable to preclude any potential bidders. Calgary stated that an asset sale involving confidential information could have the confidentiality issues addressed through confidentiality agreements.[41]

CG

It was the CG's view that the only appropriate FMV determination process would be one where that value was discovered through a fair bid and tender process, both for storage and production properties. Furthermore, the evaluation should not be limited to an either/or proposition in the sense of Carbon as a going concern or blowdown of the storage cushion gas. The CG argued it was possible that the highest value might be some hybrid situation involving partial blowdown to a level of cushion gas that provides a more economical operation of storage, given today's values of cushion gas, as compared to the cost of additional wells and compression to create the same capability for the storage operation. Similarly, full blowdown, if gas prices are high, may create the highest value.

CCA

The CCA was opposed to the method and process proposed by the applicant to remove Carbon from regulated service. The CCA argued that in Alberta there have been many transactions of utility rate base assets in recent years[42] and many of them were conducted from a utility to an arms length unaffiliated entity. In these transactions the market at large had, in some way, set the price. It was the CCA's view that these forms of price or value discovery are methods that are preferable to customers rather than a non-arms-length transaction to an affiliate.

The CCA also submitted that it might be appropriate to use separate tests for the storage facilities and for cushion gas as well as for the producing properties.

EnCana and Unocal

EnCana and Unocal submitted that a closed sale to Midstream was not an appropriate procedure for the disposition of Carbon and the producing properties. They argued that any disposition should contain the following elements:

1. an effective date for the disposition, established in advance;
2. a binding bid or tender process;
3. a tender process open to all; and
4. a floor price for the assets, to be established in advance.

EnCana and Unocal were of the view that a disposition of Carbon by way of a tendering process open to all parties, including Midstream and existing storage owners, was the only way to ensure that a disposition occurred at FMV. They argued that disposition at FMV ensured that both the new owner's entry into the Alberta storage market had not been subsidized in any way and that any future proceedings respecting the allocation of the sale proceeds between shareholders and customers would deal with a real number established by the marketplace.

41 AGS-Cal.54
42 See examples CCA Argument page 26

Views of ATCO Gas

ATCO Gas noted that considerable attention was paid in this hearing to its proposal to conduct the valuation of the assets to be transferred by means of consultant evaluation rather than through a public tendering process.[43] In ATCO Gas' view, the common objective of both approaches was to ensure that FMV was received for the storage assets as well as for the producing properties. The issue, therefore, was whether FMV could be obtained through consultant evaluation.

ATCO Gas argued that FMV could be established by an evaluation based on the average of three independent consultant assessments, since such a valuation methodology is capable of determining the price the property "should bring" or its FMV.

ATCO Gas further submitted that it had not been ordered to use a tendering process in transacting with affiliates. AGS argued that while the CG pointed to the summary portion of Decision 2000-9 in its evidence as authority for the proposition that a tendering process was required to establish the value of affiliate transactions[44], this issue was addressed in cross-examination while Mr. Engler noted that the body of Decision 2000-9 does not provide a clear direction that tendering must be used.[45] Specifically, at page 154, the Board stated:

> "CWNG must be able to substantiate the FMV of all current and future transactions, with appropriate evidence and documentation. This **may** be done through a fair bid or tendering process to both third-party providers and affiliates."(*Emphasis added by AGS)*

AGS argued that while at a superficial level there appeared to be some attraction to a tendering process in order to draw out that irrational buyer, the nature of the tendering process belied that conclusion. Further, it was equally likely that parties in the storage market will not see value in acquiring Carbon and the process would yield a lower value than consultant evaluations. ATCO Gas suggested that parties in the storage market would seek to capture value for themselves through acquiring Carbon and the process would yield tenders reflecting a lower value than consultant evaluations.

ATCO Gas also noted that while it could prohibit the disclosure of confidential information by participants through execution of a confidentiality agreement, this would be of no practical use because competitors would likely be the potential purchasers, and the information would be of greatest interest to them. ATCO Gas noted these same parties had acknowledged on the record the proprietary and sensitive nature of such information.[46] A tendering process would reduce, therefore, the value of Carbon because the eventual buyer would know that competitors had participated in the process and were fully aware of the characteristics and capabilities of the facility. Consequently it would be destructive of Carbon's competitive position in the marketplace.

AGS argued that a tendering process would not produce full value related to the full range of optionality alternatives available to a commercial operator. AGS believed it went without saying that the storage operator would want to maintain significant returns if it was going to pay for this

[43] Exhibit 3, Disposition of Carbon Storage Facilities Page 4, Exhibit 15, Additional Evidence page 2.
[44] Exhibit 87 page 14
[45] Transcript vol. 7, pages 690-691.
[46] Exhibit 11, ATCO-CGSS.2; Exhibit 11, ATCO-AEC/UNOCAL.2; Transcript vol. 9 pages 1064-1066.

highly risky endeavor. The result would be a significant discount factor being used in any calculation of the present value of the future benefit stream.

ATCO Gas submitted that there were only two evaluations that were appropriate: (i) the storage facility as a going concern (which included cushion gas) and (ii) the producing properties alone. AGS contended that valuation of cushion gas as company-owned production should not even be considered.

Board Findings

The Board notes that processes by which the appropriate value of transactions could be determined were addressed during the Affiliate Proceeding. The Board notes that parties generally favoured either FMV or Net Book Value (NBV). Parties also disagreed regarding the best method for determining FMV. The Board found in Decision 2002-069 that the transfer of assets from ATCO Electric Ltd. and AGPL to ATCO I-Tek Ltd. (I-Tek) should be made at FMV. The Board's determination of the FMV of the I-Tek transfer of assets in Decision 2002-069 incorporated the evidence of consultants. The Board notes that the I-Tek transfer of assets was an actual transaction, whereas the Carbon transfer proceeding deals with a proposed transaction.

The Board notes that all of the interveners were unanimous in their submissions that the preferred method by which to establish a FMV is to offer the assets for sale by tender. To proceed as AGS has requested, relying on consultants, would not necessarily provide numbers that would determine FMV. As Mr. DeWolf stated under cross-examination with respect to the numbers arrived at by the consultant, "At best, they're a proxy."[47]

The Board considers that the position of the interveners that consultants cannot establish a true FMV is persuasive in this instance. A succinct viewpoint was presented by Mr. Liddle's comment that "… a lot of the evaluation of storage is going to be on what Mr. Simard, I think, characterized as gut feel, a subjective evaluation."[48] The Board considers that Carbon is unique. It has attributes that are not duplicated exactly by any other storage facility, such as its size, location relative to markets and pipelines, withdrawal and injection profiles, and reservoir characteristics. Since the value of an asset such as Carbon will depend on the bidder's view of a variety of future circumstances and conditions that will be unique to each prospective bidder, it is not reasonable to expect that a consultant could provide an accurate evaluation from all bidders' viewpoints. Using three consultants and averaging their evaluations suggests an expectation that there will be one evaluation that is the highest. It is difficult to prejudge whether a prospective bidder would arrive at a similar value on which to base its bid. Averaging by its nature produces a lower value than the highest possible amount and therefore may not provide a satisfactory result.

It is clear from the direction in Decision 2000-9, dated March 2, 2000, that the Board was of the view that any sale of property to an affiliate was to be done at least at FMV. The Board stated, "In selling a service or property to an affiliate, the Company must also demonstrate that the service or property is provided at no less than FMV. Only when FMV is not reasonably available in the market should CWNG (now AGPL) be allowed to exchange the service or property at the cost-based price of that service or property."[49] The Board generally considers the tender process

[47] Transcript vol. 4, page 408
[48] Transcript vol. 7, page 803
[49] Decision 2000-9 page 157

to be superior to the use of consultants. The Board believes that the marketplace is more likely to arrive at the FMV of the Carbon assets and thus in this instance it is more reasonable to determine the FMV of Carbon by the tender process.

The Board notes that transfer pricing and the various methods whereby FMV can be determined (including tendering, benchmarking, and the use of consultants) were explored further during the Affiliate Proceeding. The Board's forthcoming Code of Conduct decision is expected to address the Board's preference with respect to transfer pricing and the methods for determining FMV.

3.5 Use of a Closed Process Transfer of Carbon to Midstream

In this section the Board will review the merits of a closed process to value Carbon, which would exclude the opportunity for third parties to present proposals and would permit the transfer of the Carbon assets directly to an affiliate.

Views of Interested Parties

Calgary

Calgary argued that the simple average of estimated values prepared by consultants would not ensure that a transfer to Midstream was at FMV. Calgary contended that if Midstream accepted the transfer, we would know that the estimated value was at or below Midstream's assessment of FMV and; if Midstream exercised its right to reject the consultants assessed value[50], we would know that the estimated value was higher than Midstream's assessment of FMV.

Calgary noted that, in support of its methodology, AGS maintained that a tender process would somehow reduce the value of Carbon because it would reduce its competitive advantage because information pertaining to reservoir performance, inventory versus withdrawal curves and inventory levels would give competitors an advantage.[51] Calgary argued it was important for the Board to understand that the information listed was to a large extent available through the Board's reservoir and production data and available to the public as was noted by Calgary's witness[52].

As noted in the previous section of this Decision, it was the position of the City of Calgary that only through the tendering process could a FMV could be realized.

CG

The CG noted that a simple average of evaluations of Carbon assets through the retention of three consultants, each of whom would perform an evaluation, would be used as the FMV for transfer to Midstream. The CG argued that while there were certainly many consultants available with expertise and substantial experience that could value the physical infrastructure assets at Carbon, including the value of the blowdown of base gas, it was not clear to the CG that a similar level of expertise and experience existed within the consultant community to determine how to value the future utilization of Carbon as a storage operation. The CG believed that a forecast of the value of future utilization formed the basis of the determination of the FMV of Carbon as an ongoing storage operation. The CG acknowledged that consultants using well-

[50] Transcript vol. 5, pages 510-511
[51] Transcript vol. 7, pages 692-693
[52] Transcript vol. 8, page 926

established standards did evaluations of producing properties repeatedly and many actual transactions occurred in the marketplace to use as benchmarks. The CG argued that there was no similar established methodology for storage evaluations.

Conceptually, and for a variety of practical reasons, the CG submitted that it would not be in the public interest for the Board to approve the disposition of Carbon to an affiliate of AGS without an appropriate public tendering process.

CCA

As noted elsewhere in this Decision, the CCA stated they were opposed to the method and process proposed by AGPL to remove Carbon from regulated service. The CCA stated in argument that it would be comforted if there were some better element of valuation such as the market at large.

EnCana and Unocal

Also as noted elsewhere, EnCana and Unocal strongly favoured a public tender to the method proposed by AGPL.

EnCana and Unocal also noted a witness for AGPL had testified that, if the Board ordered a tendering process, AGPL would still likely proceed with the sale[53] and that Midstream would still likely participate.[54]

Views of ATCO Gas

AGS noted in argument that prior Board decisions had considered that tendering was not mandatory. For example, in Decision E95110, the Public Utilities Board stated:

> "The Board has not previously required that CWNG dispose of assets by public tender, and the Board does not at this time consider that the public tender process will necessarily ensure sales at or above FMV of the property."[55]

Accordingly, ATCO Gas submitted that the valuation process it had chosen complied with the spirit and intent of the Board's directions in that it would produce a FMV for Carbon and the producing properties.[56]

ATCO Gas argued that it had presented considerable evidence to establish that there was no uncertainty or inadequacy in valuing Carbon by way of consultant evaluation and that there were consultants capable of conducting the valuation. As noted in the Attachment to the Ziff Energy Study,[57] there were a large number of storage operations in North America; the attachments to CAL-AG.50 demonstrated that there have been significant expansions of and trading in the ownership of partnership and joint venture interests in storage. All of which was to show that with all of these ownership positions, all of these expansions, all the investment, it appeared that the consultant expertise to do the valuations clearly did exist in the marketplace. AGS argued

[53] Transcript vol. 6, page 580
[54] Transcript vol. 6, page 581
[55] Decision E95110 page 9. Note-AGS had originally referenced E84090 and E84009 in error
[56] Transcript vol. 7 pages 690-691
[57] Exhibit 11, Tab B-4, Ziff Evidence, pages 7-8, Appendix A and B

therefore, that storage was hardly a business in which there was no other way to value the asset.[58] Moreover, a consultant evaluation would be required even if a tendering process were initiated. This was the case with the sale of the Viking assets.[59]

AGS further argued that it was in the best interests of both customers and the utility that Carbon sells for the highest possible price. AGS stated that considerable evidence had been presented establishing that tendering was not the way to achieve that result in this case.[60] AGS noted that competitor storage facilities and their owners individually are the logical bidders in a tendering process for Carbon. AGS expressed concern that confidential and commercially sensitive information would therefore be disclosed to these parties through their participation in the process. AGS argued that under the requirement to provide all prospective bidders with the sensitive information, the value of Carbon would be diminished because every bidder would know that existing storage owners would also have the information.

Board Findings

The Board acknowledges ATCO Gas' concern with respect to the sensitivity of certain information that would be disclosed in a tendering process. However, the Board also notes that the witnesses for Calgary were able to assemble and analyze the Carbon field and producing properties with apparent reasonable accuracy using public information available through the Board. The Board is not persuaded that the ATCO Gas concerns expressed about confidentiality are sufficient reason to avoid a public tender process. The Board expects that ATCO Gas would use confidentiality agreements on commercial terms with prospective buyers to allow them access to data as is typically done in the industry.

Further, the Board directed in Decision 2000-9 and in Decision 2002-069, that asset transfers between a utility and non-regulated affiliates must be at FMV, which the Board in this instance, considers can best be achieved through public tender. The Board finds that it would not be appropriate to permit a transfer to Midstream through a closed process.

Consequently, a condition that must be met by ATCO Gas, if it desires to sell, is that Carbon must be sold by public tender. The Board recognizes that there are different tender processes that can be used in transactions and considers that it will be necessary to receive recommendations from ATCO Gas prior to any sale as to appropriate tender design. Therefore the Board directs ATCO Gas to submit recommendations on tender design for approval before proceeding with a sale process. The Board expects the tender process would adhere to certain general characteristics. The Board believes that the process must be reasonably transparent. The tenders should be submitted in the form of a closed bid by a preset deadline, to be opened in the presence of interested parties and a representative of the Board. The final bids should be binding and submitted subsequent to the bidder substantially completing its due diligence. The highest, least conditioned bids would be given preference, and all bids could be rejected by ATCO Gas. The Board believes at present that the preferred bid value would at minimum be equivalent to the blow down value of the cushion gas.

58 Affiliate Exhibit 131: CAL-ATCO.120(a); Transcript vol. 7 pages 799-804; Affiliate: CROSS-AG.4; Affiliate Exhibit 22: CAL-AG.50; Affiliate: CAL-ATCO.85
59 Exhibit 106, ATCO Gas Rebuttal Evidence page 14
60 Exhibit 106, ATCO Gas Rebuttal Evidence pages 14-15; Transcript vol. 6 page 578-581, Transcript vol. 7, pages 691, 693, 731, 732

The Board acknowledges that the ATCO Group has stated that it would like to remain in the storage business. Therefore, the Board also agrees with the interveners that Midstream would be an eligible bidder, but should be afforded no special treatment.

Following selection of the preferred final bid, ATCO Gas would make application for the sale of Carbon in a public proceeding. This proceeding would address the no-harm value. If the bid did not meet the no-harm value, the Board would not approve the disposition. If the bid exceeded the no-harm value, the proceeding would also address the allocation of proceeds between the shareholders and customers.

The Board expects that it will hear submissions as to the appropriate sharing of proceeds based on arguments brought forward in a number of recent proceedings. In addition, the Board would be prepared to entertain submissions to the general effect that it should use its broad powers to condition its decision to strike a balance of fairness between utility shareholders and utility customers.

3.6 No-Harm Test

In this section the Board will focus on the method used to address and mitigate the prospect of possible harm to customers in the event that the approval to dispose of regulated assets is requested, in this case Carbon.

Views of Interested Parties

Calgary

Calgary took the general position in its evidence that the issue was not safe and reliable service, rather it was safe and reliable service at the lowest reasonable cost. Calgary submitted that without Carbon it would be impossible for AGS to provide safe and reliable service at the lowest reasonable cost.

Calgary argued that one advantage of retaining Carbon versus alternatives was the operational flexibility, including control of required daily volumes when needed at a cost certain. Calgary claimed that this reduced the retail core market customer risk related to price volatility especially in a high priced market. Calgary was of the view that replicating the operational flexibility of Carbon was difficult at best except under a 100% spot gas purchase strategy which Energy Objective’s evidence showed was less beneficial in the long run to customers than paying for the use of the Carbon facility.

A second advantage, argued Calgary, were the benefits resulting from the ability to change withdrawals at any time during the day so as to avoid having to either purchase more gas or to sell more gas if the weather fluctuates. This flexibility was not easily replicated through third party arrangements although the market could be relied upon at some cost.

A third operational advantage related to the contract with ATCO Pipelines South (APS). Calgary argued that the use of Carbon should allow AGS to contract for less capacity on APS and thus reduce its costs.

Calgary was of the view that the information it had put together indicated that with the appropriate revenue credits, the storage for AGS could be provided at little or no cost and in some years at a negative cost.

Calgary argued that to the extent that there was in fact surplus capacity at Carbon, third party operational arrangements could be entered into by ATCO Gas and if those operational arrangements were priced at market based rates (subject to open season bids) then the customers of ATCO Gas would be assured that they were receiving fair value for the surplus capacity. Calgary stated that leasing of surplus capacity to one party without the benefit of market input exposed the customer and the shareholder of ATCO Gas to the potential loss of income that a market based approach might provide. Calgary noted that under the existing arrangements the shareholder was not exposed to any potential loss, because any loss of revenue was borne by the customers, while Midstream, which the shareholder also owns, got the benefit of the storage at rates which had not been set in the marketplace.

Calgary argued that for at least as long as AGS provided the merchant function to its customers, the Carbon storage facility as a legacy utility rate base asset should be used for the benefit of rate payers regardless of the degree of competitiveness exhibited by the storage market. On the other hand, the determination of benefit arising from the discontinuation of the storage operation would have to exceed the long term benefit of storage and some future value of blowing down the cushion gas (one would assume that the present value of the blow down scenario would be the driving force behind discontinuing storage).

Calgary stated that should the Board decide that the storage and/or production assets are to be removed from regulatory service, the customers must be sheltered from all harm that would result from such action. This harm included the total FMV adjusted for asset related costs and AGS'S administration and overhead costs as outlined in the Sproule report[61]. Calgary believed that all value related to this asset rested with the customer.

Calgary argued that the production of indigenous supplies was of value to customers as this production displaced the gas purchases at market prices and that the value of the storage operation as a going concern also rested with the customer. When cushion gas is produced, the entire value of that asset flows to the customer via the DGA. This position was confirmed by the Board in Decision 2001-110 which stated:

> [I]f the alternative selected involved the production of base gas, the Board agrees with Calgary that the volumes produced would be part of the gas supply, treated as COP, and would be dealt with in the DGA process.[62]

Calgary noted that the liability for all costs associated with the Carbon reservoir including royalty costs on production, the cost of protective acreage to prevent third party drainage of cushion gas as well as all other asset related and operating costs were the responsibility of the ratepayer. Further, AGS had always recognized these costs as costs to be borne by the ratepayer.

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[61] Sproule Associates Limited, Methodology for the Determination of Value for Carbon Storage and Production Assets, Discussion Section A.2, page 6

[62] Decision-2001-110, Methodology for Managing Gas Supply Portfolios and Determining Gas cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding, Part B-1: Deferred Gas Account Reconciliation for ATCO Gas, page 18

When there was the potential for the Alberta government to charge royalty on indigenous gas reserves used for cushion gas, AGS naturally expected to transfer this cost to ratepayers. The only reason it was not charged to customers was because the cost was not incurred.

Calgary submitted that the scenario most likely to produce the lowest no-harm value appears to be one that would contemplate the blow down of the storage reservoir such that the base gas is produced as COP (based on Calgary's evidence the net present value would be approximately $90 million)[63]. Other scenarios, which would contemplate a delayed blow down preceded by a period of continued use as storage, could produce benefits that would result in a no-harm value that exceeds the aforementioned minimum value (based on Calgary's evidence the net present value would have a range of $106 - $191 million, depending on how long the blow down was delayed)[64].

CG

The CG noted as indicated in Decision 2001-46, the Board in Decision 2000-41,[65] "recognized that it should conduct a balancing of both the potential positive and negative impacts of the transaction *to determine whether it is in the overall public interest."* Specifically, the Board stated:

> "As a result, rather than simply asking whether customers will be adversely impacted by some aspect of the transaction, the Board concludes that it should weigh the potential positive and negative impacts of the transactions to determine whether the balance favours customers or at least leaves them no worse off, having regard to all of the circumstances of the case. If so, then the Board considers that the transactions should be approved."[66]

The CG also noted that the Board went on to state that some form of mitigation might be necessary to ensure that customers were left at least no worse off.[67] The CG argued that this was to be distinguished from any subsequent process employed for the sharing of proceeds between customers and shareholders of the utility.

The CG noted that AGS took the position that removal of Carbon storage from regulated service would not result in harm to customers, because there were no identifiable long-term benefits and supported its position by reference to the 2001/2002 winter season where Carbon storage was not required for "operational purposes". The CG argued that the AGS position constituted a very narrow definition of "harm" and did not reflect the loss of value to customers in evolving market circumstances.

The CG argued that the Carbon storage assets to be transferred could only be valued for the purpose of the "no-harm" test based on a calculation of the loss to customers of future benefits. The CG stated that this was essentially the same in conceptual terms as the process for

63 Sproule, Methodology for the Determination of Value for Carbon Storage and Production Assets (As of January 1, 2002), page 13
64 Ibid
65 TransAlta Utilities Corporation, Sale of Distribution Business (July 5, 2000).
66 Decision 2000-41, page 8
67 2001-46, page 12

determining harm in the Viking disposition proceeding. The CG stated that the calculation requires consideration of the maximum future value of Carbon assuming it continued to be owned as a utility rate base asset, having regard to its best utilization reflecting the changed and evolving market circumstances. The CG considered that future utilization could involve one or more of the following aspects:

(a) A storage facility capable of a blended use of serving AGS customers and third parties (i.e. a continuation of present utilization practice).
(b) 100% utilization of the facility in an aggressively managed fashion to capture full optionality values and therefore create maximum savings to customers or revenue credits to the cost of service if the same use was provided.
(c) On a contract basis with third parties.
(d) A source of COP or portfolio gas through the sale or use by customers of all recoverable cushion gas reserves including the remaining value of the storage infrastructure when production of cushion gas was completed.
(e) Some hybrid mode of operation wherein a combination of the above uses creates the highest value.

The CG argued that AGS had the initial burden of both identifying and evaluating the maximum "no-harm" amounts and interveners, such as the CG, would file their interpretations of these "no-harm" tests. The CG's view was that ultimately the transfer to an affiliate or a sale to a third party must produce sufficient proceeds to prevent harm to customers as determined by the Board.

The CG submitted that the most important and appropriate direction that the Board could give with respect to the "no-harm" test was that it must take into account the future highest value use of Carbon in exactly the same manner as the Board did in Decision 2001-46 and Decision 2001-65.

CCA

The CCA submitted that a calculation of a no-harm test must be done at a specific point in time against a specific sale, offer or proposal. For example the CCA noted that discount rates vary with the general interest rate levels, and natural gas prices vary significantly at varying points in time. The CCA argued that the appropriate time frame of the no-harm standard was as of the date of the sale or transfer closing, and that the calculation of no-harm must include the full value of all aspects of Carbon, including, but not limited to, seasonal and operational storage, parking, swaps, peaking, exchange service, transportation costs minimization, purchasing, load and factor improvement, blow down of cushion gas, and third party contracts.

The CCA considered that there was greater operational flexibility with Carbon than without. The removal of Carbon from rate base, by the very nature of Carbon, will reduce the availability to ATCO Gas of sources of natural gas.

Views of ATCO Gas

ATCO Gas noted that the Chairman set out the issues that the Board would address in this phase of the hearing process at the outset of the hearing. AGS stated it did not include the determination of the "no-harm" value, which would be addressed in the second phase should the Board approve the removal of Carbon from regulation. While AGS believed it was inappropriate to delve into the details of the no-harm calculation in this phase of the proceeding, it noted that customer rates would decrease as a result of removing Carbon from regulation.

It was the view of AGS that as a matter of principle, the Board had applied the no-harm test in other applications in a way that compared ongoing costs to ongoing benefits to determine a net benefit/cost.

ATCO Gas submitted that the methodology used in the Carbon matter should be the same, with no-harm determined by comparing annual costs to annual benefits on a go forward basis. It was AGS's opinion that the costs and benefits should reflect continued utility service, not competitive storage options.

AGS argued that the suggestion that Carbon storage was "financially sensible" was only supportable if ATCO Gas accepted that it would have to undertake a program to capture as much value from intra-seasonal optionality as possible.[68] ATCO Gas reiterated its position that these types of activities represented a radical change of use for Carbon storage, were not appropriate for utility service, and had in fact, been prohibited most recently in Decision 2001-75. ATCO Gas argued that it was not and should not be required to "beat the market". ATCO Gas submitted that its position was captured succinctly by Mr. Engler as follows:

> "I think we've been pretty clear in our filed evidence that, from our perspective, there is no harm to customers as a result of removing Carbon from utility service. In essence, if you just think of the Viking example, as a result of selling Viking, rates went up; as a result of removing Carbon from utility service, rates will go down."[69]

and:

> "There's nothing magic about Carbon. I guess what I'm saying is, if the Board wants us to have storage, then let's go to the marketplace and let's buy some storage. Let's not assume that Carbon is the storage facility that we have to be in, because it's not."[70]

ATCO Gas also submitted that the valuation of cushion gas (or "base gas") would be considered as part of the overall evaluation of the storage business undertaken by the three consultants.[71] AGS stated that, under that process each of the consultants would be afforded access to ATCO Gas' confidential reservoir data, costs and other information relevant to the valuation. Each consultant would generate its own assumptions regarding the capabilities and costs of the storage field and producing properties under a blowdown scenario.[72]

ATCO Gas did not believe that the blowdown of cushion gas was appropriate. ATCO Gas considered that the cushion gas at Carbon was intrinsic to the storage business at Carbon. As such, the value of the cushion gas could be separated from the value of the storage business. ATCO Gas argued that to direct the Carbon blowdown was tantamount to directing the destruction of the Carbon storage business.

[68] Transcript vol. 8 page 849
[69] Transcript vol. 6 page 603
[70] Transcript vol. 7 page 682
[71] Decision 2001-75 Section 6.4.2 page 95.
[72] Transcript vol. 5 pages 505, 506, 507

Board Findings

When dealing with the sale of regulated assets the Board has established the no-harm standard, which was discussed at length in Decision 2001-65, dated July 31, 2001.[73] The practice of the Board to establish a no-harm value, which must be exceeded by the proceeds to be distributed to customers, is to ensure that customers will be no worse off than they would have been if the asset(s) was retained.

A utility is faced with making choices between alternatives in its normal course of doing business. There are a number of examples where alternatives exist and are evaluated on an ongoing basis to determine the economic choice that will be of benefit to customers, such as leasing or owning a fleet of vehicles, heavy equipment, office space, and communication towers. In such cases where an asset is not yet owned, a company will make a buy or lease decision based on the economics. For a gas utility, even the investment in new pipes is subject to economics where it will not always invest 100% of the capital, but will require a contribution by third parties to meet an economic criterion of not harming existing customers. In a case where the asset is already owned, an economic evaluation is made of alternatives to assist in choosing the alternative that will not harm the customers. In this case, Carbon provides a service that has been and could continue to be beneficial to customers. ATCO Gas has proposed that owning the asset is no longer necessary as other alternatives now exist that can replace Carbon. Accepting that alternatives exist, it would be reasonable to measure the value the customers must receive in order to dispose of the asset in favor of using an alternative. In essence, the no-harm evaluation which the Board uses is the economic test to establish a threshold value for the minimum net proceeds of a sale which should be available for distribution to the customers. The amount of proceeds must meet or exceed the no-harm threshold in order for the sale to be approved. If the no-harm threshold cannot be met, then it follows that maintaining ownership provides the customer with the greatest economic benefit.

When Carbon was first established as a storage facility in 1968, it was at a time when alternatives to storage did not exist, and to facilitate the need for cushion gas the production of the indigenous gas was suspended. In effect, customers forwent company-owned production (COP) from Carbon in order to accommodate the conversion of a producing field to a storage field without the need to inject base gas. It was also recognized that CWNG did not require the entire working capacity of the facility. When utilizing an existing reservoir for storage it is not always possible to perfectly match the utility’s requirement with the capacity of the storage facility, especially when proximity to the market is a major consideration. Indeed, Carbon has always accommodated third party storage. Today, the Board and interveners agree that there are alternatives to Carbon. However, as indicated earlier in this Decision, the presence of alternatives does not preclude Carbon from continuing as a “used and useful” asset. The Board previously accepted Carbon as used and useful[74], and considers that it still retains used and useful characteristics. However, as stated earlier, the Board does believe there is some uncertainty as to the degree that Carbon is required to be used. Therefore, if ATCO Gas wishes to sell Carbon and as a result have it removed from regulated service, it must persuade the Board that there is no detrimental impact on its customers (no-harm) that cannot be mitigated.

73 Sale of Certain Petroleum and Natural Gas Rights, Production and Gathering Assets, Storage Assets and Inventory, pages 8-11
74 Decision 2000-9, page 42

The Board notes Calgary's position that the scenario that would likely produce the lowest no-harm value would contemplate the blow down of the storage reservoir such that the base gas is produced as COP. Based on the evidence of Calgary's expert, the net present value would be approximately $90 million[75]. Other scenarios, which would contemplate a delayed blow down preceded by a period of continued use as storage, could produce benefits that would result in a no-harm value that exceeded this minimum value. Calgary's expert indicated that the net present value would have a range of $106 - $191 million, depending on how long the blow down was delayed[76].

The Board notes, however, that ATCO Gas does not agree that customers should receive any value from the base gas. The Board is not prepared to accept this position of ATCO Gas at this time. In proceeding with the next phase to finalize a transaction, the Board believes that ATCO Gas must be prepared to address the position that the base gas value would be considered in the determination of the parameters for and the calculation of the no-harm value. It appears to the Board that ATCO Gas would have to address the argument that base gas could be produced (actually or by displacement), delivered to customers as COP and the benefit distributed in accordance with the COP Rider mechanism as directed in Decision 2001-75.

Normally, the Board would expect the no-harm threshold to be determined in conjunction with a request for approval of a sale that included a firm price from a willing buyer.

The Board recognizes that a no-harm value is derived using information and assumptions available at the time and the value would therefore only be applicable for a short period. This fact makes it appropriate to establish the actual no-harm value at the time a sale transaction is contemplated.

It is clear to the Board that establishing a no harm value could be a complex calculation requiring experienced judgment to set the assumptions that would underpin the calculation. ATCO Gas suggested that the services of three consultants could be used to calculate FMV, with the chosen FMV being the average of the three submissions. If all interested parties can agree, the Board is willing to consider a similar process to calculate a no-harm value. The value might also effectively be established by a negotiated settlement among interested parties.

3.7 Matters Brought Forward from the GRA and Affiliate Proceedings

GRA Issues

This section of the Decision deals with GRA-related issues in the Carbon Transfer Proceeding. In a letter dated April 2, 2001, ATCO Gas requested that all affiliate transactions arising in the context of the ATCO Gas 2001/2002 GRA be deferred and heard as part of the ATCO Affiliate Proceeding. ATCO Gas attached to that letter information identifying the affiliate transactions that ATCO Gas proposed be moved to that hearing, including the following items related to Midstream for the 2001/2002 test period.

[75] Sproule, Methodology for the Determination of Value for Carbon Storage and Production Assets (As of January 1, 2002), page 13
[76] Ibid

	Forecast 2001	($000) 2002
Revenue		
Office Services	11	11
Gas Storage	12,120	13,920
	12,131	13,931
O&M		
Gas Management	500	500
Gas Storage Services	950	950
	1,450	1,450

Subsequent to the filing of the April 2, 2001 letter, ATCO Gas filed its application on July 18, 2001 to seek approval to withdraw the Carbon Storage Facility from regulated service and rates. In light of that application, the AGS 2001/2002 GRA matters were deferred from the Affiliate Proceeding to the Carbon Transfer Proceeding.

Forecast Revenues

This section of the Decision deals with the appropriateness of the fee charged by AGS to Midstream for the uncontracted capacity at Carbon, and with issues related to the termination of the Firm Service Gas Storage Agreement between Northwestern Utilities Limited (NUL) and CWNG dated February 1, 1993 (the "NUL Agreement").

Views of Interested Parties

Calgary

Calgary noted that Decision 2000-9 found that CWNG was deemed to have received $0.32 for the non-contracted capacity sold to Midstream's predecessor, ATCO Gas Services. Calgary also noted that the value of $0.32 was originally supported by the Ziff report, and was specifically filed to address the long-term lease arrangement proposed with Midstream for the Affiliate Application. Calgary pointed out that, in the Board's letter of December 21, 2001 the Board advised AGS that Decision 2000-9 had not determined the appropriate value for storage for any year other than the 1998 test year. Calgary indicated that the Board also advised that it was for AGS to establish the prudent rate in the context of the present application, and that AGS may find it necessary to file further information.

Calgary referred to its testimony in the Affiliate Proceeding which indicated that regulated utility transactions with an unregulated affiliate should always be at the higher of cost or market. Calgary pointed out that, in Decision 2000-9, the Board strongly suggested that storage services and the addendum to Gas Service Storage Agreement between CWNG and Midstream, dated December 15, 1999 (Uncontracted Capacity Agreement) should be tendered. Calgary stated that, while Midstream has paid slightly less than cost (based upon the 1998 cost of service study) in the last few years, this does not mean that ratepayers have received market compensation. Calgary considered that, to the extent that a below market rental fee for the uncontracted capacity has allowed Midstream to achieve profits, ratepayers have not participated in these profits generated from the rate base asset. Calgary stated that the potential value (excluding operating costs) to Carbon's customers ranged from $0.62/GJ on a long-term basis (10 years) to $5.40 on a short-term basis.

Calgary stated that current long-term market based storage rates ranged from $0.42/GJ to $0.74/GJ, noting that EO had submitted that these rates exceeded the current cost of service to Carbon's customers of $0.33/GJ. Calgary considered that the methodology used and the price of $0.32 used by AGS and purportedly supported by Ziff Energy's evidence was inconsistent with proper storage valuation.

Calgary pointed out that Ziff Energy was retained to evaluate the price to be paid under a 10 year lease, not the short term Uncontracted Capacity Agreement. Calgary stated that Ziff Energy's sole reliance on historical data to determine future storage value was refuted by AGS's other experts, Mr. Simard and Mr. DeWolf. Calgary noted that these experts admitted that the historical methodology was inappropriate for short-term future storage value determination. Calgary submitted that, in the absence of a market based price determined through an open season method, a more appropriate process would involve an ex-ante approach as presented by EO in evidence. Calgary pointed out that EO's evidence indicated that Midstream could have benefited to the extent of $3.04 per GJ ($3.36 net of $0.32 paid to AGS) for the capacity for the 2001/2002 storage year. Calgary noted that this amount excludes the optionality value.

Calgary indicated that AGS could have received a portion of the value of $3.77/GJ ($4.09 net of $0.32) in an open season determination conducted for both the 2000/2001 and 2001/2002 storage seasons. Calgary submitted that, for the 2002/2003 storage year, the revenue from Midstream should be a minimum of the summer/winter differential of $0.84/GJ[77], recognizing that this amount does not reflect the benefits of operating the storage field, nor the optionality value.

Calgary submitted that the revenue requirement should be credited for the cancelled NUL Agreement, stating that no prudent party would allow termination of a long term arrangement without some form of compensation. Calgary stated that the revenue from the NUL Agreement, absent the actions of AGS, would have been a credit to the 2001/2002 revenue requirement. Calgary pointed out that the agreement had a 20-year term with a 5-year termination notice. Calgary noted that AGS had indicated that the value of the storage would be $1.36/GJ for 2001/2002 and $0.45/GJ for 2002/2003. In 2000 the revenue recorded was $4.073 million. Calgary submitted that the unilateral termination of this contract has deprived AGS customers of a significant gross revenue benefit of $12.24 million for 2001 and $4.05 million for 2002. Calgary noted that, compared to the $0.32/GJ used in the 2001/2002 AGS GRA, the net loss to AGS ratepayers was $9.36 million in 2001 and $1.17 million in 2002.

CG

In the opinion of the CG, valuations that result in extreme values (i.e. negative or in excess of $1.00/GJ) are not reasonable and would not be entered into in the real market place. The CG stated that, in the same manner as the Board had originally adjudicated a price of $0.32/GJ by reference to the actual market prices in the 1997/98 GRA proceeding, a value for years 2000/2001 and 2001/2002 should be similarly tested against the best evidence available of actual market transactions. The CG stated that evidence was placed on the record that the price paid for third party storage contracts obtained by AGS on behalf of its customers for the 2001/2002 year was $0.17/GJ. While the CG took no issue that this was a real price for real storage equivalent service, the difficulty with that price was that it reflected a value for storage with limited flexibility (e.g., without optionality) that was not in any way comparable to the values inherent in

[77] As discussed at Transcript vol. 1 page 180

the more flexible capacity made available to Midstream under the Uncontracted Capacity Agreement. The CG stated that this was particularly true for the 2001/2002 storage season when the full 43.7 PJ of capacity was made available to Midstream.

The CG stated that a better price reference would be that provided by Calgary based on the AECO C storage rate calculator. The CG noted that Mr. Walsh offered the view that $0.65/GJ was a reasonable interpretation of an average result that could be obtained from this calculator and that this result would be clearly a benchmark for actual negotiations for full-service storage in the marketplace. The CG noted that it was Mr. Walsh's opinion that this was a reasonable basis to determine the market value of storage at a point in time in advance of the actual storage season. The CG recommended that the Board fix the price within a range of $0.17 to $0.65/GJ, but with a clear and significant weighting to the upper end.

With respect to the NUL the contract, the CG noted that the agreement allowed NUL to store "up to a total of nine (9) PJ" of gas, and that the contract arrangement was terminated, by mutual agreement, effective April 1, 2001. The CG quoted AGS evidence that the pricing provisions of the NUL Agreement were based on market conditions existing in the early 1990s. The CG referred to AGS's comment that, with the recent run up in gas prices, the price falling out of the formula in the contract was not a market price, and that any third party storage holder of such a contract would be seeking similar relief. The CG noted that, based on the contract lease rate of "fifteen percent (15%) of the previous Contract Year IAURP", the storage rate would have been as high as $1.36/GJ. The CG considered this well out of the market and noted that AGS had taken the position that the $0.32/GJ charge paid by Midstream represented the appropriate compensation for the 9 PJ of storage capacity.

The CG noted that the NUL Agreement could be terminated at law by mutual consent, and submitted that no minimum storage quantity was specified and, during the term of the contract, NUL was not obliged to put any gas in storage. The CG stated that, although NUL had the ability to store up to a total of 9 PJ, lease payments were based on actual injections, which could be nil, and submitted that the issue for the Board to determine is whether it was prudent for CWNG and NUL to terminate this contract. The CG indicated that clearly, customers were not involved. The CG stated that it would be unfair to suggest that AGN (NUL) customers should be responsible for any real or perceived loss of revenue, and submitted that, if the Board determines there was lack of prudence, any required compensation to AGS customers should be borne by shareholders.

CCA

The CCA considered that the 2001/2002 storage revenue forecast was understated. Assets in rate base should be credited with all revenues associated with those assets. These revenues should include, but not be limited to, all amounts associated with seasonal and operational storage, parking, swaps, peaking, exchange service, transportation costs minimization, purchasing, load and factor improvement, blow down of cushion natural gas, and third party contracts.

Edmonton

Edmonton considered that the NUL storage contract was reasonable and prudent at the time it was entered into, given the climate of the industry in 1993, and despite not having been involved with termination of the contract, Edmonton's view was that termination was reasonable and prudent. Edmonton submitted however that, if the Board determines that the termination was not reasonable or prudent, any increase in rates experienced by AGS ratepayers as a result of Edmonton ratepayers no longer paying storage charges should not be a cost borne by Edmonton ratepayers. Edmonton stated that its ratepayers derived no benefit from having storage available after the date of termination and were in no way involved with decisions made with respect to the contract. Accordingly, Edmonton stated that its ratepayers should not be responsible for compensating AGS customers for any increase in rates caused by a loss of third party storage contract revenue credits to the Carbon cost of service. Edmonton noted Calgary's acknowledgement that the contract was considered appropriate even though the pricing mechanism resulted in NUL obtaining storage at a price that was less than the Carbon cost of service in some years.[78] Edmonton submitted that, even though the price of the storage per the contract formula in those years may have been somewhat low relative to the Carbon cost of service, it had not been shown to be significantly out-of-market.

Edmonton considered that the issue with the NUL Agreement was whether the termination of the contract was a reasonable and prudent action. Edmonton pointed out that AGS's evidence was that there was no longer any need for third party storage in the AGN portfolio. Edmonton noted that this decision was made at the same time as the decision with respect to eliminating the use of storage in AGS, resulting in the proposal by AGS to remove Carbon from utility service and lease 100% of the capacity to Midstream.

Edmonton considered that the timing of the decision to terminate the contract was important, since the contract was terminated before the high gas prices in the winter of 2000/2001 had actually occurred. Edmonton considered therefore that the termination decision could not have been made primarily on the basis of the pricing provisions in the NUL Agreement, but rather on the fact that AGS had determined that storage was no longer required for utility service as a general principle. Edmonton stated that, as events unfolded with the very high prices in the winter 2000/2001 season, the pricing provisions in the NUL Agreement that were based on market conditions in the early 1990's created prices in the contract that did not reflect a market price. Edmonton submitted that this provided additional support for the appropriateness of the decision to terminate the contract. In Edmonton's view, this decision was reasonable given that pricing terms were significantly out of market, and accordingly termination was a reasonable and prudent course of action and one that customers would have also expected the companies to make in an arms length situation.

Edmonton submitted that continuing with the NUL Agreement would have been imprudent and would have resulted in a major transfer of revenues from AGN customers to AGS customers for no discernable public interest benefit viewed from a total ATCO Gas service area perspective. In contrast to Calgary's position, Edmonton considered that AGS acted reasonably in weighing the relative impacts to the two customer groups. The negative aspects of a substantial out of market storage price premium to the 2001/2002 costs for AGN customers, for storage not actually used, far outweighed the perceived benefits to AGS customers arising from windfall revenue that has little or no relationship to the actual cost of gas or its delivery.

Edmonton referred to Calgary's claim that AGN customers should pay $12.24 million in storage costs for the storage year 2001/2002 and $4.05 million for storage costs for the storage year 2002/2003. Edmonton noted that Calgary based its claim on what it saw as an entitlement that

[78] Transcript vol. 8 page 913

AGS customers enjoy as a result of the revenue generated by the NUL Agreement.[79] Edmonton did not accept the existence of any such entitlement. Edmonton noted that, in response to a question whether there is any provision in the NUL Agreement for a minimum physical amount of injection or withdrawal annually, Mr. Engler replied that there was no minimum specifically identified.[80] Edmonton stated that the only reference to quantities in the NUL Agreement was to NUL taking up to 9 PJ[81] and paying according to a formula based on the Contract quantity stored at Carbon. Edmonton stated that taken together, these facts tend to indicate that the physical operation and operability of the storage facility were not dependent on the NUL commitment, and that there was an expectation of a reduction in terms of the volume of storage that NUL would actually use in any specific year. Edmonton stated that the contract did not provide any certainty of AGS customers being entitled to a full (or any) revenue stream when storage was not used or was used to a lesser extent.

Edmonton stated that AGN customers did not receive any service after the termination of the NUL Agreement and it followed that it would be unreasonable for them to pay for a service they did not receive. Edmonton submitted that, if the Board should find that the parties to the contract were imprudent in their termination of the contract, any financial implications should ultimately be the responsibility of the parties to the contract. In this regard, Edmonton noted Calgary's statement that if the contract termination is found to be imprudent, it does not matter who provides the credit to the AGS revenue requirement, but that it is reasonable that management of ATCO Gas should be responsible for any compensation to AGS customers. Edmonton stated that it should be remembered that AGS customers would still receive revenue for the storage capacity that AGN did not use in the 2001/2002 and 2002/2003 storage years. Edmonton indicated that this revenue would arise through the Midstream contract at a rate that will be adjudicated by the Board.

Views of ATCO Gas

AGS stated that, in its 2001/2002 GRA application, it developed its storage revenue forecast based on the assumption that Carbon would be leased to Midstream effective April 1, 2001. AGS noted that, in addition, AGS provides office services to Midstream, and that the forecast revenue for this service was $11,000 for each of the test years. AGS submitted that interveners took no issue with this forecast and that it should be approved by the Board.

AGS indicated that it operates with Midstream under the Gas Storage Services Agreement entered into on February 20, 1998 between CWNG and ATCO Gas Services Ltd. (now Midstream) (the "Gas Storage Services Agreement"), which reflects the arrangement as it stood at the time of filing its Affiliate Application on July 21, 2000. AGS pointed out that, on January 15, 2001, the agreement was extended for a period of one year, and that apart from changes to the term, the agreement currently in effect is the same as that found in the Affiliate Application at the price approved by the Board in the CWNG 1998 Phase I GRA.

AGS indicated that, consistent with the requirement for prospectivity in ratemaking, AGS was required to determine appropriate storage prices for the 2001/2002 period on the basis of price forecasts. AGS indicated that the Ziff Report set out an appropriate price forecast for the 2001/2002 period based upon certain assumptions, one of which included the long-term lease

[79] AGS-CAL.12.
[80] Transcript vol. 6, page 614
[81] Exhibit 156, Article 2.1.

proposal. AGS considered that it was appropriate to rely on this price forecast, which was based on certain assumptions including the long-term lease proposal, as forming the basis of pricing for storage for the period in question. AGS pointed out that the price ($0.32/GJ) was “the price and arrangement stipulated by the Board in the 1998 Phase I GRA”.

AGS stated that the $0.32/GJ fee was derived from both the Ziff study filed in the Affiliate Application and the Board's determination that a $0.32/GJ rate was the appropriate fee for the Uncontracted Capacity Agreement in the 1998 Phase I GRA.

AGS noted that the Board used “firm, long-term service” storage contracts to determine the value of storage services under the Uncontracted Capacity Agreement in Decision 2000-9. AGS stated that the Uncontracted Capacity Agreement had been put before the Board in the 1998 GRA proceeding and was approved, except for price and pricing methodology.

AGS considered that normally the Board and interveners would expect AGS to reflect the last approved uncontracted capacity rate in its financial information for utility purposes until the Board directs the change in a subsequent hearing. On this basis, AGS noted that the Board and interveners would expect that same rate to be reflected in its 1999 and 2000 utility financial results, and would only change once the Board considered new evidence at a subsequent hearing.

AGS indicated that Mr. Engler also explained the reasonableness test that AGS applied to the determination of the rate.[82] Mr. Engler stated that, if the pricing methodology found on Schedule B of the previous contract for the 2000/2001 storage year[83] was applied to the next two contract years, the average of the two years would have produced a number less than $0.32/GJ. Accordingly, AGS submitted that in fact, customers benefited. AGS submitted that the long-term price of $0.32/GJ, which is methodologically consistent with the long-term valuation used by the Board in Decision 2000-9, well exceeds the market price, to the clear benefit of customers. AGS considered that, while the market price for 2002/2003 may be higher, the price over the two test years is reasonable. AGS stated that the forecast had to be made at the time of the filing of the GRA, not in hindsight.

AGS stated that, despite its analysis, interveners proposed and the Board approved the contracting of third party storage (11 PJ) at various load factors at a substantially lower average cost (approximately $0.17/GJ) than the owning and operating cost of Carbon. AGS pointed out that the Uncontracted Capacity Agreement is an addendum to the Gas Storage Services Agreement.

AGS stated that for the test year 2002, the ten-year rolling average would increase due to the abnormal summer/winter differential that occurred in 2000/2001, but would be capped at a 20% increase on the $0.24/GJ, the previously calculated 10-year average. AGS indicated that this results in a value of approximately $0.29/GJ. Added to this amount would be the suggested 33% optionality value for a total storage transfer price approximately equal to $0.38/GJ for the 2002 test year.

AGS stated that EO’s value of up to $5.40/GJ is completely unreasonable and based upon hindsight analysis of selected seasonal differentials rather than information that existed at the

82 Transcript vol. 5, page 476
83 Exhibit 11, Affiliate Application Volume 4 Tab A-2.

time of the filing. AGS stated that Ziff Energy could have demonstrated that the EO approach would have yielded values less than $0.32/GJ in a number of years, using a similar analysis. AGS stated that EO could have based the one-year storage value on the average seasonal differential forecast during February/March 2001, which would have yielded a storage valuation of negative $0.18/GJ. AGS considered that utilizing a combination of actual and forward prices on December 21, 2001 (EO's dated report), the 2001/2002 one-year seasonal differential could have yielded a value of negative $1.60/GJ. AGS stated that depending on the strategy undertaken, swings from the high positive values ($5.40/GJ) to large negative values (-$1.60/GJ) could be observed, and submitted that EO was incorrect in asserting that it has used the same methodology as that used in Ziff Energy's February, 2001 report to establish a long term price. AGS stated that the premise that anyone could have recovered $3.36/GJ for the use of Alberta storage over the past winter is impossible to reconcile with market reality. Specifically, AGS indicated that the extraordinary values of $4.09/GJ and $3.36/GJ were approximately twenty times higher than the price that was actually obtained on the open market through an open bid process. AGS pointed out that its acquisition of 11PJs of storage by means of an open bid process at a cost of $0.173/GJ was less than the owning and operating costs of Carbon.

With respect to the NUL Agreement, AGS indicated that the pricing provisions of that agreement no longer reflected current market prices for storage[84] as was the intention when the agreement was first entered into.[85] AGS noted that another storage agreement with a third party with similar pricing provisions was terminated, and indicated that the revenue forecast did not include revenue from AGN for the 2001/02 storage year as the NUL Agreement was terminated prior to this storage year.[86] AGS submitted that it was appropriate to terminate this agreement, and that in doing so AGS was balancing the interests of AGN and AGS customers. AGS submitted that Calgary's estimate of the potential loss to customers of AGS resulting from termination of the contract was incorrectly calculated. AGS calculated that the loss for 2001 should be $8.08 million instead of $9.36 million as calculated by Calgary, and indicated that the NUL Agreement would have been limited to the 2001/2002 storage year, as AGN would have had to terminate its third-party storage contracts effective April 1, 2002 pursuant to Decision 2001-75. AGS did not believe that any adjustment to revenue requirement was warranted.

Board Findings

The Board notes from Decision 2002-069 that "…the Board prefers the option of using FMV transfer pricing for major ongoing transactions…".[87] The Board considers that Carbon storage revenue is a major ongoing transaction, and believes that all parties to the Carbon Transfer Proceeding would agree.

The Board acknowledges that the forecast revenue from ATCO Midstream for 2001 and 2002 for use of the uncontracted capacity at Carbon is based on the fee of $0.32/GJ as determined by the Board in the 1998 CWNG Phase I GRA, and substantiated in the study filed by Ziff Energy in the Affiliate Proceeding. The Board notes the comments of AGS filed in evidence to support the appropriateness of the fee, including the observation that the long-term price of $0.32/GJ well exceeds the market price to the clear benefit of customers, and the expectation that the rate would change only after consideration of new evidence in a subsequent hearing.

[84] Transcript Vol. 4, Page 420
[85] Transcript Vol. 5, Page 471
[86] Transcript Vol. 4, Page 452 -453
[87] Decision 2002-069, page 85

The Board has considered the evidence of Calgary, the CG and the CCA in this proceeding in support of their submissions that, while the fee was established based on market conditions prevailing at the time of the 1998 GRA, the amount of the fee needs to be re-assessed in light of current market conditions and proper storage evaluation practices. The Board notes the wide range of values recommended by interveners with respect to the amount of the fee, and the evidence provided by AGS to challenge the validity of those recommendations. The Board notes Calgary's comment that Decision 2000-9 had not determined the appropriate value for storage for any year other than the 1998 test year, and that AGS needed to file further information to establish the prudent rate in the context of the present Application. The Board agrees with Calgary that AGS has this responsibility, and acknowledges the comments of interveners with respect to determination of the rate based on prevailing market conditions. While in agreement with the submissions of interveners that market conditions would appear to support a fee higher than that presently charged to Midstream, the Board considers that the wide range of market-based values recommended does not facilitate an accurate determination of an appropriate fee.

The Board agrees with the submission of the CG that valuations that result in negative amounts or values in excess of $1.00/GJ are extreme and unreasonable, and unlikely to be entered into in the market place. The Board also notes that, excluding such outliers, the values that could be considered as a fee for the uncontracted capacity fall within the range of $0.17/GJ paid by AGS in the market for third party storage contracts for the 2001/2002 storage year and $0.65/GJ referred to by the CG based on the AECO C storage rate calculator provided by Calgary. The Board also recognizes that AGS provided evidence in response to CAL-AG.10, that a 2002 cost of service analysis resulted in a rate of $0.33/GJ, and referred to a rate of $0.38/GJ for 2002 calculated using the formula designed by Ziff Energy in its evaluation of the long-term lease arrangement. Another alternative of interest to the Board is the long-term market based rate quoted by Calgary of $0.42/GJ to $0.74/GJ.

The Board established the storage fee in Decision 2000-9 based on third party bids for long-term storage contracts. Given the absence of such compelling evidence to support a specific valuation in this instance, the Board is of the view that establishment of a fee in the mid-range of the two market values of $0.17/GJ and $0.65/GJ would be appropriate for the 2001/2002 test years. The Board is not persuaded that the fee should be set at the higher end of the range, as proposed by the CG, but considers that a more conservative approach would be appropriate, consistent with the view taken by the Board in establishing the fee of $0.32/GJ in the 1998 GRA.

Accordingly, for the 2001/2002 test years and remainder of the period up to end of 2002/2003 storage year, the Board directs AGS to reflect the revenues from Midstream based on a fee of $0.41/GJ. The Board expects that AGS will conduct a market based evaluation to determine the amount of the fee for storage years subsequent to 2002/2003. The Board considers that a tender process for the uncontracted capacity would reveal the FMV and that it would be preferable to use a tendering process in support of an application by AGS when submitting its evidence to demonstrate the prudence of the arrangement. The Board considers there are benefits to a prospective process rather than relying on consultant evaluations after the fact. In the Board's view, if the process were to permit an affiliate to match the highest bid, it would be in keeping with the general sense of satisfying the Board's concerns with respect to affiliate transactions.

The Board holds the view that, when a utility provides a material or significant service to a non-regulated affiliate, the utility should receive FMV for the service. However, the Board considers that the utility should monitor how the FMV compares to the cost of providing the service. Accordingly, to establish the cost of service benchmark, the Board directs AGS to determine the costs incurred in providing the uncontracted capacity service in the cost of service study to be filed in the 2001/2002 Phase II GRA. The Board expects that the costs allocated to the uncontracted storage capacity in the cost of service study will recognize usage based on the appropriate ratios of capacity and deliverability.

The Board considers that there is merit in AGS's submission that the pricing provisions of the NUL Agreement no longer reflected the current market and that, in terminating the agreement, AGS was balancing the interests of customers in the North and South. The Board also notes Edmonton's comments with respect to the prudence of the decision to terminate the contract. The Board acknowledges the concerns of interveners that customers were not involved in the decision to terminate the storage agreement with NUL, and that cancellation of the NUL Agreement has deprived customers of AGS a significant revenue benefit. The Board agrees with interveners that existence of the NUL Agreement would have resulted in the generation of revenue, available for offset against the 2001/2002 revenue requirement.

The Board acknowledges Edmonton's submission that AGN customers did not receive any service after termination of the NUL Agreement, and that it would be unreasonable for them to pay for a service they did not receive. In this regard, the Board notes that, based on AGS's submission that the storage costs were a DGA flow-through, termination of the NUL Agreement would have no impact on customers in the North. The Board is prepared to accept that the termination was the result of an informed business decision, and acknowledges the comments of AGS and Edmonton that by making that capacity available to Midstream, AGS has taken steps to mitigate the potential loss to customers in the South.

However, the Board notes Calgary's submission that, after allowing for the offsetting revenue from Midstream, there was still a loss to AGS customers of $9.36 million (2001) and $1.7 million (2002). The Board also notes that AGS calculates the loss for 2001 at $8.08 million, based on the methodology used by Calgary. The Board has examined the respective calculations and acknowledges that both calculations are based on the assumption of a requirement by NUL to pay for 9 PJ of storage gas whether or not the full contract capacity was injected. In this regard, the Board has reviewed the relevant wording of Article II of the NUL Agreement, and agrees with the CG that the agreement appears to allow NUL to store "up to a total of nine (9) PJ" of gas in each storage year. The Board considers therefore, that it is far from clear that AGS would have been entitled to the revenues from storage of a full 9 PJ of gas if the NUL Agreement had been in place during 2001 and 2002. Accordingly, the Board is not persuaded that there is any basis to conclude that the amount of any potential loss to AGS customers arising from the cancellation of the NUL Agreement would be as significant as that calculated by Calgary. The Board is satisfied therefore, that in making that capacity available to Midstream, AGS has taken action to mitigate the potential loss to customers in the South. This alleviates to some degree concerns that the Board might have with respect to the prudence of a decision to terminate an agreement in a non-arms length situation.

The Board notes AGS's submission that interveners took no issue with the revenue forecast for office services provided to Midstream. The Board accepts as reasonable the revenue forecasts of $11,000 in each test year for office services provided to Midstream.

Operating and Maintenance Expense (O&M)

This section of the decision deals with issues related to the fees paid by AGS for services provided by Midstream for gas management under the Gas Management Services Agreement between AGPL and Midstream, dated January 1, 2000 and gas storage services under the Gas Storage Services Agreement. The amounts included by AGS as expenditures in the 2001/2002 test years are $500,000 for gas management and $950,000 for gas storage services.

The Board addressed this type of transfer pricing situation in Decision 2002-069. The Board determined that, "On an ongoing basis, AGS must initially justify its decision to 'outsource' or 'insource' the service involved, especially if the service is already being performed within the utility. This is consistent with the asymmetric pricing recommended by Calgary and FIRM/Core with respect to services provided by non-regulated affiliates to the regulated utilities. After the initial test is satisfied, whether AGS is dealing with an affiliate or an arms length third party, the Board expects AGS to obtain services at FMV. The Board also expects AGS to be diligent in the ongoing management of the price and the need for the services contracted".[88]

Views of Interested Parties

Calgary

Calgary submitted that it was totally inappropriate for AGS to capitalize 20% of the fee, and submitted that no request for proposal (RFP) or independent evaluation had been conducted relative to the Gas Storage Services Agreement. Calgary noted that no evidence was provided to substantiate the appropriateness of the fee.

Calgary submitted that evidence provided by Ziff Energy in August, 2000, highlights the practice of tender by utilities of gas management service to the market, and indicated that other utilities with storage assets went through an RFP process. Calgary indicated that Ziff Energy's evidence dealt only with the remuneration reasonableness and not the process itself. Calgary pointed out that AGS chose to continue its obligation to Midstream without the benefit of an RFP to determine if customers could pay less.

CG

The CG submitted that for the 2001/2002 Storage year (April 1, 2001 to March 31, 2002), the payment made to Midstream for storage management services under the Gas Storage Services Agreement should be reduced by 25%, which would be prorated to calendar years 2001 and 2002. The CG considered that, since Carbon storage was being utilized for utility customers prior to April 1, 2001 and after March 31, 2002, the storage management services fee for those periods is judged to be appropriate.

The CG stated that for the year 2001/2002, when AGS made a unilateral decision not to utilize storage for utility purposes, there was no storage capacity from the Carbon reservoir for Midstream to manage. The CG stated that Midstream was paid a management fee to manage storage, which it had fully contracted to itself, thereby creating a conflict situation. The CG stated that it did not seem reasonable for AGS to be paid a management fee for capacity, which was available to Midstream as a profit-making opportunity. The CG pointed out that AGS had not provided any evidence to demonstrate that the management of third-party storage acquired

[88] Decision 2002-069, page 78

for 2001/2002 required the same level of expenditure as that required for management of the Carbon storage reservoir. The CG submitted that, in the absence of such evidence, the Board should make a downward adjustment of 25% to the storage management fee.

The CG noted that Mr. DeWolf concluded that Midstream's fee of $0.005/GJ under the Gas Management Services Agreement was below the fee charged other utilities and aggregators. The CG noted that AltaGas Utilities Inc. (AUI) was a notable omission from Mr. DeWolf's study. The DeWolf study states that AUI has paid AltaGas Services a gas fee (and third party costs) since May 1999 (two separate contracts) for the management of 13 Bcf/y of gas sales service and 6.2 Bcf/d of gas transportation service. CG stated that if AUI buys 13 Bcf of GCRR Gas as Mr. DeWolf identifies, it would appear that AUI's management fees at $0.0086/GJ are somewhat higher that Midstream's, which is reasonable given the economies of scale in portfolio management. The CG noted that two elements are missing from Mr. DeWolf's study. First of all, the CG stated that there had been a lack of any actual testing of the market for provision of these services. The CG pointed out that secondly, information was missing regarding the costs of gas management when insourced, as it once was. The CG stated that this should be tested at the next GRA both by outsourcing and insourcing, which would ensure that Midstream continues to be the least-cost option for customers.

Views of ATCO Gas

AGS stated that the O & M forecast for gas management and storage services for each of the test years is $1,450,000, of which $950,000 is the O&M portion of the fee for storage services. AGS stated that a list of the related evidence filed in the 1998 CWNG GRA was provided by AGS in Exhibit 163R, and pointed out that, in that material, the response to CAL-CWNG.7 indicated the fees that were charged for the period 1996 to 1998. AGS pointed out that the fee charged in 1998 has not escalated, and submitted that the historical relationship of the fee to the costs incurred by AGS prior to the establishment of the Gas Storage Services Agreement is reasonable. AGS stated that the services performed have remained the same, and that no studies were filed by interveners refuting the level of the fee. Referring to the CG's recommendation for a 25% reduction in the storage fee, AGS stated that the fact that AGS did not use Carbon during the period in question does not mean that Carbon was not used or did not have to be operated. AGS submitted that in fact, Carbon had to be operated in order to generate the revenue credits, which defray the cost of owning and operating Carbon storage. AGS expressed the view that there was no basis to make the kind of arbitrary disallowance suggested by the CG.

AGS stated that the Gas Management Services Agreement fee ($500,000 per year) was addressed by Ziff Energy in the Gas Service Cost Assessment report filed in the Affiliate Proceeding. AGS noted that the fee was reasonable given Ziff Energy's experience in these matters, indicating that there was little discussion of this issue and that no studies were filed by interveners disputing the level of the fee. AGS noted that Calgary also agreed that the gas management fee appeared to be reasonable.

Board Findings

The Board notes AGS's submission that the fee for the Gas Management Services Agreement was addressed by Ziff Energy in a report filed in the ATCO Affiliates Proceeding and that given the experience of Ziff Energy in these matters, AGS concluded that the fee of $500,000 was reasonable. The Board also acknowledges the concern of Calgary and the CG that Ziff Energy dealt only with the reasonableness of the fee and not the process that should be in place to establish the fee. However, in the absence of studies filed by interveners to support an adjustment to the fee, the Board will accept AGS's forecast. Nevertheless, the Board acknowledges intervener concerns with AGS's choice to continue its obligation to Midstream without the benefit of an RFP to determine if customers could pay less. Accordingly, the Board expects that, at the termination of the existing contract, AGS will establish future agreements for gas management services through use of an RFP process. Alternatively, AGS may use consultants to determine the FMV of services provided by Midstream based on the findings of Decision 2002-069. In that Decision the Board directed ATCO, "…prior to any future material engagements of consultants to undertake a price review applicable to I-Tek and the regulated Utilities, to file terms of reference applicable to the engagements. Following participation of the parties, the Board will make a preliminary determination as to the reasonableness of those terms of reference to assist in providing a complete and useful record for future applications".[89]

The Board notes AGS's submission that the fee for the gas storage services contract has not changed since 1998, the services performed have remained the same, and that the amount of the fee is reasonable. While acknowledging intervener concerns that no RFP process or independent evaluation has been conducted relative to the storage services agreement, the Board notes that no studies or other evidence have been filed to support an adjustment to the fee. The Board notes the observation of the CG that a reduction to the fee may be warranted given that the uncontracted capacity at Carbon was not used for the benefit of utility customers for a significant portion of 2001 and 2002. Specifically, the CG refers to the period between April 1, 2001 and March 31, 2002. On the other hand, the Board acknowledges AGS's observation that in fact, Carbon had to be operated during that time to generate the revenue credits, which defray the cost of owning and operating Carbon storage. However, the Board notes that the terms and conditions of Schedule A to the Gas Storage Services Agreement include the following clauses setting out the services to be provided under the agreement, by Midstream for operation of the storage facility on behalf of CWNG:

- Receive storage injection and withdrawal nominations from CWNG gas operations control centre and operate storage facility to meet these nominations
- Receive storage injection and withdrawal nominations from customers and provide confirmations to those customers that nominations are within contracted levels.

The Board also notes that Schedule A includes clauses covering provision of marketing services, and planning and administration of the storage facility on behalf of CWNG.

The Board considers therefore that, since Midstream no longer operated any part of the capacity of the storage facility on behalf of AGS during the periods referred to by the CG, none of the above services would have been provided by Midstream for AGS. Accordingly, the Board agrees with the CG's recommendation that the payment to Midstream for gas storage services should be reduced by 25%, prorated to the appropriate proportion of calendar years 2001 and 2002 to apply the reduction to only the period when there would have been no usage of Carbon for utility customers. The Board therefore directs AGS to reduce the payment for gas storage services for the 2001/2002 storage year by $237,500. The proportion of the reduction attributable to the test years will be $178,125 for 2001 (covering the months from April to December) and $59,375 for 2002 (covering the months from January to March). The Board's comments with respect to

[89] Decision 2002-069, page 53

determining the FMV for the Gas Management Services Agreement also apply here to the Gas Storage Services Agreement.

4 JURISDICTION

Views of Interested Parties

Calgary

Calgary submitted that the Board must concern itself with the regulation of gas delivery services and the provision of gas supply by AGS at just and reasonable rates. Calgary argued that the Board's jurisdiction and regulatory focus with respect to Carbon has always been and continues to be with respect to the impact of Carbon storage on the rates AGS charges in respect of gas delivery and supply services. Calgary expressed the concern that the rates for delivery services provided by AGS might increase in the event Carbon were transferred to ATCO Midstream. Calgary suggested that AGS was wrong when it suggested that the jurisdictional issue before the Board in these proceedings involves the Board's ability to require AGS to enter into an unregulated storage services business to offset ratepayer costs. Rather, the appropriate jurisdictional question to be addressed in these proceedings is "In regulating the provision of gas delivery service and gas supply service, does the Board have the jurisdiction to refuse to allow a rate base asset to be sold because it considers that asset could be useful in providing utility service by reducing rates." Calgary submitted that Carbon could be useful in providing utility services by reducing costs if AGS chose to utilize this legacy asset in that manner. The fact that AGS has chosen not to use Carbon in this manner in recent years does not detract from the position that the asset has been used and could be used again to reduce gas costs to ratepayers.

CG

The CG questioned the purpose of the present application in the absence of a real transaction to be considered under Sections 26(2)(d) of the GUA and Section 101(2)(d) of the PUB Act. The CG went on to suggest that "if the Board were to determine that the Carbon facilities are no longer required for utility service, any direction regarding removal from rate base should be conditional upon an application pursuant to Section 26 of the GU Act, a determination of resulting harm and confirmation of the allocation of proceeds as between shareholders and customers." In the CG's view, the Board should not be approving the removal of the Carbon facility from rate base as requested by AGS in the absence of a Section 26 application, rather, they submitted that the "Board need do nothing more than determine whether the facilities are required by AGS for utility operational purposes". The CG viewed this determination as a first step in a process that would require a broader no-harm analysis prior to any approval to remove the asset from rate base pursuant to a subsequent application under Section 26 of the GUA.

CCA took issue with the manner in which AGS purported to limit the jurisdiction of the Board with respect to services that may be available on a competitive basis. The CCA referred to Section 29 of the Ontario Energy Board Act as an example of one jurisdiction's approach to limit a regulatory tribunal's ability to deal with an issue before it where there is sufficient competition to protect the public interest with respect to the issue. Without a similar statutory limitation, the CCA argued that it would be improper to attempt to limit the Board's jurisdiction with respect to services that may be also provided in the competitive marketplace.

The CCA also referred to several case authorities for the proposition that the Board has clear discretion to determine what is rate base and in exercising that discretion, the Board's finding cannot be an error going to the jurisdiction of the Board. In particular, the CCA referred to the judgment of the Supreme Court of Canada in *Northwestern Utilities Ltd. v. City of Edmonton* [1929] S.C.R. 186, and the statement of Lamont, J. at page 196: "The items which should be included in rate base cannot, in my opinion, be considered a question of jurisdiction or of law." Similarly, the CCA found it significant that there were no Alberta case authorities that require an asset to be removed from rate base where competition for the subject service develops.

Views of ATCO Gas

AGS argued that Carbon is not "used or required to be used to provide service to the public within Alberta" as set out in Sections 37(1) of the Gas Utilities Act and Section 90 of the Public Utilities Board Act. In AGS's submission, the Board has discretion to determine if an asset should remain in rate base, but in exercising that discretion it must be used properly and may not ignore relevant considerations. In AGS's view it is not appropriate to include an asset in rate base only because it is owned by a regulated utility if that asset is not "used or required to be used to provide a regulated service to the public." Drawing on the Apollo[90] decision of this Board, AGS argued that it is the role of the Board to regulate a utility's monopolistic or non-competitive functions. Assets that have historically been included in rate base that no longer are required to provide monopolistic or non-competitive services at just and reasonable rates should be removed. AGS argued that Carbon is no longer "used or required to be used" to support the regulated monopoly functions of natural gas supply and natural gas distribution. Further, AGS argued, even if natural gas storage services were required in connection with such regulated monopolistic services, such natural gas storage services are readily available in the competitive market place. If Carbon is not appropriately in rate base, AGS asserted, then the Board lacks the jurisdiction to direct AGS to retain Carbon in rate base and to require AGS to offer storage services into the marketplace with the proceeds of such storage services being used to subsidize ratepayer costs. AGS submitted that any such storage services could not be appropriately considered to be "utility services" and that there was no justification for requiring the utility to offer such services, especially in consideration of receiving a regulated rate of return on rate base. In AGS's view, should the Board require AGS to offer such services, it would, in effect, be requiring AGS to carry on a non-utility, non-regulated business with assets which should be considered as non-utility assets, all for the benefit of utility ratepayers. This, AGS argued, would be beyond the Board's jurisdiction.

Board Findings

The Board has found in Section 3.1 of this Decision that, although there is some uncertainty as to the degree of usefulness of Carbon, it cannot at this time determine that there would be no harm to AGS's customers if Carbon were not in regulated service, given the evidence suggesting that Carbon continues to be required in serving the AGS market and the failure of the evidence to date to convince the Board that Carbon is not a useful asset. Consequently at present Carbon shall remain in rate base and be subject to regulation by this Board.

In respect of the entire storage capacity of Carbon, however, the Board understands that currently AGS does not require the full capacity for utility purposes. Over the last several years, AGS has

[90] Decision 2000-10: Apollo Gas Inc. Complaint Against northwestern Utilities Limited and ATCO Gas and Pipelines Ltd. operating as ATCO Gas with respect to Termination of Billing Services.

dealt with this extra capacity through an assignment to its affiliate, Midstream, in consideration for a payment that has been credited against the costs of Carbon charged to utility ratepayers. The appropriate rate to be paid by ATCO Midstream from time to time has been the subject of this and prior proceedings. Profits, if any, realized by Midstream from the operation of its storage business, have not been shared in any manner with utility ratepayers. This mechanism is intended to preserve Carbon as a rate base asset to be used in connection with utility services as and when required and as and when economically prudent to do so, and to offset the rates otherwise payable by ratepayers by the payment of fair compensation for the use by Midstream of that portion of the utility asset not required from time to time by the utility.

Subject to the provisions of Section 3.7 of this Decision, dealing with the appropriate payment by Midstream for the use of uncontracted capacity at Carbon, the Board believes that the present arrangements are a satisfactory method of dealing with the excess capacity not required from time to time by the utility. Such arrangements do not require the profits or losses generated through the operation of a storage business by Midstream to be shared with utility ratepayers, nor do they require the regulated utility to undertake a non-regulated service or to operate a non-regulated business for the benefit of ratepayers. Given this result, the Board does not believe it is necessary to address the jurisdictional issues raised by AGS.

However with respect to the Apollo decision, to which AGS addresses itself in particular, the Board notes AGS's argument that assets which have historically been included in rate base and are no longer required to provide monopolistic or non-competitive services at just and reasonable rates should be removed from regulated service. The Board would comment that it considers a more balanced expression of principle, given its current jurisprudence and its wide discretion in determining an appropriate rate base, would state that assets which have historically been included in rate base and are no longer required to provide monopolistic or non-competitive services at just and reasonable rates may be permitted by the Board to be disposed of, provided customers are not harmed as a result. The Board would refer in general to the difficulty, discussed during the hearing, in making a hard and fast rule as to the precise nature of: (i) assets that should in all events be owned by the utility to provide utility services (thus given rate base treatment), (ii) assets which should in no event be owned by the utility, and (iii) assets which could be owned by the utility or which could be leased, acquired through services agreements or otherwise. This difficulty is exacerbated by the development of market alternatives.

In conclusion, until such time as AGS brings an application to sell Carbon pursuant to an actual transaction and the Board renders a favorable decision, Carbon will remain in rate base as a regulated asset to be operated by AGS in a prudent fashion, in accordance with this Decision and in the manner contemplated by Decisions 2001-75 and 2001-110. Should AGS prefer an alternative course of action, it is free to bring a future application to dispose of Carbon in accordance with the guidance set out in this Decision or to negotiate a different arrangement with its stakeholders for approval by this Board.

The Board expects that the additional direction provided herein will provide sufficient guidance to AGS in structuring the use of Carbon while it remains in rate base while clarifying that the Board is not requiring AGS to operate a merchant storage business for the benefit of utility ratepayers.

5 SUMMARY OF MATTERS RELATED TO THE DISPOSITION OF CARBON

As noted in Section 2 of this Decision ATCO Gas requested the following:

(a) approve the withdrawal of Carbon from regulated service and rates; and
(b) establish a process by which the FMV of Carbon could be determined so that the facility could be transferred to Midstream..

It proposed that a withdrawal of Carbon be addressed in three steps:

1. Included as a part of the Application and as a consequence of approval of withdrawal from regulation, ATCO Gas sought approval of a process for determining the FMV of Carbon.
2. Subsequent to receiving the applied for approvals, ATCO Gas would then implement the process to determine the FMV of Carbon.
3. In an ensuing application, ATCO Gas would request approval of an allocation between it and customers of the proceeds paid by Midstream.

The Board has attempted to address the provisions of the Application in various sections of this Decision. As an aid to the reader the Board will hereafter set out a summary of its various determinations that respond to the noted provisions of the Application. In the event of any differences between the summary and the related language found in the main body of this Decision, the wording in the main body shall prevail.

Summary of Determinations:

- The Board considers that the continued use of Carbon by ATCO Gas could be useful, especially while the retail market is under development. (Section 3.1)
- The Board considers that there is evidence to indicate that Carbon continues to be a used and useful regulated asset, notwithstanding there are alternatives to its use available. The status quo operation of Carbon on a prudent basis would appear to be appropriate at the present time. (Section 3.1)
- The Board would expect that if ATCO Gas in future decides to enter into a transaction to dispose of Carbon in a way that meets the no-harm requirements of the Board, the next step would be an application for Board approval pursuant to section 26(2)(d) of the GU Act. (Section 3.2)
- The Board would expect to see a fully defensible land packaging proposal from ATCO Gas on any future application to sell or otherwise dispose of Carbon. This proposal would involve transfer of ownership or control of potential migration or drainage lands or wells to the purchaser of the storage reservoir. (Section 3.3)
- The Board finds it would not be appropriate to permit a transfer to Midstream through a closed process. (Section 3.5)
- Consequently, a condition that must be met by ATCO Gas, if it desires to sell, is that Carbon must be sold by public tender. (Section 3.5)
- The Board directs ATCO Gas to submit recommendations on tender design for approval before proceeding with a sale process. (Section 3.5)

- The Board agrees with the interveners that Midstream could be an eligible bidder but should be afforded no special treatment. (Section 3.5)
- The amount of proceeds must meet or exceed the no-harm threshold in order for the sale to be approved. If the no-harm threshold cannot be met then it follows that maintaining ownership provides the customer with the greatest economic benefit. (Section 3.6)
- If ATCO Gas wishes to sell Carbon and as a result have it removed from regulated service, it must persuade the Board that there is no detrimental impact on its customers (no-harm) that cannot be mitigated. (Section 3.6)
- In conclusion, until such time as AGS brings an application to sell Carbon pursuant to an actual transaction and the Board renders a favorable decision, Carbon will remain in rate base as a regulated asset to be operated by AGS in a prudent fashion, in accordance with this Decision and in the manner contemplated by Decisions 2001-75 and 2001-110. Should AGS prefer an alternative course of action, it is free to bring a future application to dispose of Carbon in accordance with the guidance set out in this Decision or to negotiate a different arrangement with its stakeholders for approval by this Board. (Section 4)

6 ORDER

THEREFORE, it is hereby ordered that:

(1) For ATCO Gas, a Division of ATCO Gas and Pipelines Ltd.:

The Carbon Storage Facilities will remain in rate base as regulated assets to be operated by ATCO Gas – South in accordance with this Decision and in the manner contemplated by Decisions 2001-75 and 2001-110 until such time as a future application may be brought before the Board to dispose of Carbon in accordance with the guidance set out in this Decision or, for approval by this Board of a negotiated settlement by ATCO Gas – South of a different arrangement with its stakeholders for the use of Carbon.

(2) For the 2001/2002 test years ATCO Gas – South will:

(a) reflect the revenues from ATCO Midstream Ltd. for uncontracted capacity based on a fee of $0.41/GJ, including for purposes of the storage rider.

(b) reflect the annual revenues from ATCO Midstream Ltd. for office services in the amount of $11,000.

(c) reduce the payment for gas storage services for the 2001/2002 storage year by $237,500. The proportion of the reduction attributable to the test years will be $178,125 for 2001 (covering the months from April to December) and $59,375 for 2002 (covering the months from January to March).

(d) reflect charges to ATCO Midstream Ltd. in the amount of $500,000 for gas management services.

Dated in Calgary, Alberta on July 30, 2002.

ALBERTA ENERGY AND UTILITIES BOARD

<original signed by>

B. T. McManus, Q.C.
Presiding Member

<original signed by>

M. J. Bruni, Q.C.
Acting Member

<original signed by>

C. Dahl Rees
Acting Member