Ontario Power Generation Inc. ("OPG")
Interrogatories for CCC/VECC

INTERROGATORY #1

Ref: Page 18, schedule 13

Preamble: Dr. Booth discusses bond yield spreads.

Interrogatory

Please provide the underlying yields for Schedule 13. What is the average term to maturity for each of the bond series in Schedule 13?

The spreads are attached. The bonds are long term so the actual maturity varies, but generally they target 17-18 year bonds.

INTERROGATORY #2

Ref: Page 22, lines 4-5

Preamble: Dr. Booth states that he does not see a decline of 50 basis points in A spreads as being significant.

Interrogatory

Please identify what period Dr. Booth is referring to when he says that there has been a decline of 50 basis points in A spreads.

Dr. Booth is referring to the difference between long Canada yields at the time of the Board review of its adjustment mechanism in 2003 (5.29%) and his current forecast (4.75%).

INTERROGATORY #3

Ref: Page 21, lines 22-23

Preamble: Dr. Booth presents yields and spreads for A rated bonds in December 2007.

Interrogatory

Please provide the corresponding yields and spreads as of end of April 2008.

Dr. Booth declines the request. This is not an appropriate comparison since the yields are as of the time that Dr. Booth prepared his testimony. Otherwise evidence is constantly changing. If requested Dr. Booth will update relevant data at the time of his testimony.

INTERROGATORY #4

Ref: Page 42, line 6

Preamble: Dr. Booth states that PNG's loss of load dwarfs anything that could conceivably affect Gaz Metro.

Interrogatory

a) Did Dr. Booth mean OPG?

b) Would Dr. Booth please confirm that even with the assistance that has been provided by the BCUC, PNG is still rated BBB (low) with a negative trend by DBRS?

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a) No, OPG does not have "load" in the same sense. Dr. Booth regards Gaz Metro and PNG as the riskiest gas utilities in Canada but the discussion that follows shows just how much riskier PNG is than Gaz Metro.

b) Yes. As Dr. Booth states on page 43

The BCUC can and has used this regulatory protection for PNG, but it cannot prevent a death spiral.

INTERROGATORY #5

Ref: Page 43, lines 18-20

Preamble: Dr. Booth discusses the shareholders' experience in PNG.

Interrogatory

a) Could Dr. Booth please confirm that the share price of PNG was approximately $27 at the end of 1998?

b) Could Dr. Booth please confirm that the share price of PNG was under $7 at the end of April 2001?

c) What is PNG's current allowed common equity ratio and what is its year end 2007 common equity ratio?

Please indicate the period over which Dr. Booth concludes that PNG's shareholders earned a reasonable ROE and provide all empirical support for that conclusion.

A) & b) **t**he following graph indicates PNG's monthly price. A high of over $30 and a low of $7 in the recent past seems reasonable. This stock price volatility is what is picked up in the beta risk measure. Note that while an investor who bought at $30 and sold at $7 would lose money, equally obvious is that someone who bought at $7 and sold at $18 made money.

C & d) PNG's 2007 annual report indicates the following:

> The Fort St. John/Dawson Creek division allowed 2007 return on common equity was 8.77 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 40 basis points over the low risk benchmark utility rate of return for the Fort St. John/Dawson Creek division.

> The Tumbler Ridge division allowed 2007 return on common equity was 9.02 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 65 basis points over the low risk benchmark utility rate of return for the Tumbler Ridge division.

At year end 2007 PNG had $72 million in debt and $81 million in equity for an equity ratio of 51%, which includes some preferred shares and reflects PNG's share of the KSL project development. Reasonable is in the context of the typical ROEs contained in Dr. Booth's Appendix B. PNG stated the following about is financial results:

> "2007 was a year of solid operating performance and notable achievements. we strengthened our financial position by securing new long term debt financing on favourable terms, giving the company more flexibility to pursue strategic initiatives."

Reasonable would be consistent with the company's description of solid.

INTERROGATORY #6

Ref: Page 43, lines 10-12, footnote 13

Preamble: Dr. Booth indicates that "the allowed ROE is for the Fort St. John region where the allowed ROE is the lowest so the shortfall is minimized."

Interrogatory

a) Please explain in more detail why Dr. Booth used the Fort St. John allowed ROE as a comparison to the actual ROE.

b) Please indicate the percentage of total rate base that the Fort St. John operations account for in relation to the total.

c) What were the corresponding allowed ROEs for PNG (West).

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a) b) & c) The allowed ROEs were provided in answer to question 5. The ROE comparison was simply to show that PNG had under earned and this is clearer with the lower allowed ROE region. The annual report does not seem to indicate the division of the rate base and non-utility assets, so it does not seem possible to work out an average "allowed" ROE.

INTERROGATORY #7

Ref: Page 59-60

Preamble: Dr. Booth estimates the cost of equity using the tax-corrected financial leverage equation.

Interrogatory

a) Please confirm that the tax-corrected financial leverage equation predicts that the after-tax cost of capital will continue to decline as the debt ratio rises. If this cannot be confirmed, please explain why not.

b) Please calculate the cost of equity that would result at a 70/30 debt/equity capital structure from using unlevered costs of equity of 6% and 8%, a debt cost of 5%, a corporate tax rate of 36.12% and the assumption that the after-tax/pre-tax costs of capital do not vary as debt is added to the capital structure.

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a) Correct to a degree. It assumes that the after tax WACC declines in the relevant region.

b) Dr. Booth does not understand this question as there is no basis for the assumption that the after tax cost of capital does not vary with leverage. He would also need to know this un-varying after tax cost of capital to use as a starting point.

INTERROGATORY #8

Ref: Pages 57-58

Preamble: Dr. Booth provides the risk rankings (e.g., average risk, above average risk) assigned by RBC to various power and pipeline funds.

Interrogatory

Please provide the corresponding risk rankings assigned by RBC to the Energy Infrastructure Corporations (Enbridge, TransCanada, etc).

The analyst following those stocks does not provide a DCF analysis or a comparable risk ranking.

INTERROGATORY #9

Ref: Page 60, lines 13-17 and page 61, lines 1-5

Preamble: Dr. Booth references the unlevered equity returns of Bruce.

Interrogatory

a) Please confirm that the middle of the 9.5% to 13.5% range would be 11.5%.

b) Using Dr. Booth's tax-corrected financial leverage equation, what is the indicated ROE at a 40%/60% debt/equity capital structure?

c) Using the assumption that the after-tax/pre-tax cost of capital does not change as more debt is added to the capital structure, what is the levered ROE at an 11.5% unlevered equity cost and a 40/60 debt/equity capital structure?

d) What are the corresponding ROEs using the assumptions/equations in (b) and (c) at a 10% unlevered equity return?

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a) Dr. Booth is pleased to confirm that the mid-point of 9.5% and 13.5% is 11.5%
b) This is impossible to answer as the question is not clear. The indicated ROEs are in the graph on page 59.
c) Please see Dr. Booth's answer to 7b.
d) Please see Dr. Booth's answer to 7b.

If the question is asking for the equity cost assuming that the weighted average cost of capital stays at the 10% unlevered cost, so the after tax cost of capital is constant, then this answer would not be consistent with the existence of an optimal capital structure or the discussion in Dr. Booth's testimony on pages 27-33 where he discusses the tax advantages of using debt financing. Such an answer would also not reflect the real world experience that the market values tax shields.

INTERROGATORY #10

Ref: Page 61, lines 1-5

Preamble: Dr. Booth concludes that "this would place the fair return at significantly less than this 10% unlevered cost."

Interrogatory

a) Please explain why the comparison is to the 10% rather than the middle of the range value of 11.5%.

b) When Dr. Booth uses the term "fair return" does he mean return on rate base or return on equity?

c) If return on equity, please explain why an unlevered return on equity would be directly comparable to a levered return on equity for OPG?

d) Please provide Dr. Booth's quantification of the unlevered cost of equity for OPG's prescribed assets, and provide a detailed explanation of all assumptions and inputs.

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a)The 10% is the rate of return that TransCanada is forecasting as an unlevered after tax return on Bruce Power's nuclear assets, assuming a 10% increase in capital costs. As Dr. Booth states these investments do not include the same level of regulatory protection afforded OPG's nuclear assets, so the required return on these assets would be lower.
b) Equity.
c) It wouldn't and Dr. Booth does not claim that it does. Dr. Booth used the Bruce Power information to place these assets in the context of the unlevered equity costs discussed on pages 57-58.
d) This is contained throughout Dr. Booth's evidence. His recommended ROE is 7.75% with a 40% common equity ratio. Dr. Booth does not make an unlevered equity cost recommendation for the reasons stated on page 26-27, namely:

> "Second, allowing firms to chose their capital structure and then adjusting the ROE to a fair return runs the risk that although the equity holders are getting a fair rate of return the overall utility income and thus rates are too high and unfair. An extreme example here would be a firm that "chooses" 100% equity financing. The regulator might then give a fair return, but rates are still unfair and unreasonable, since the company is forgoing the advantages of using debt financing."

100% equity financing is the same as the unlevered equity cost and would result in unfair and unreasonable rates.

INTERROGATORY #11

Ref: Page 77

Preamble: Dr. Booth discusses the Siegel article and his observation that the US TIPS yield was 4.0%, leading to the conclusion that actual bond returns were 1.8% less than expected.

Interrogatory

a) What has been the average yield on long-term TIPS over the past five years?

b) If the originally observed 4.0% overstates the long-term required real return on bonds, how does that alter Dr. Siegel's conclusion that actual bond returns were 1.8% less than expected?

c) If, as the Ibbotson Associates data on equity risk premiums in the U.S. indicate, the income return on long-term government bonds was 5.2% (arithmetic average) from 1926 to 2007 and the total return on long-term government bonds was 5.8% (arithmetic average) from 1926 to 2007, does this comparison indicate that, on average, bond investors earned less than expected? Please explain the response.

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a)US TIPs yields are graphed in Schedule 8, the average has been about 2.5%.
b)If 4.0% is the long run expected yield on US government bonds then the realised bond return of 1.3-2.2% is less than expected which has caused the over-estimation of the US market risk premium as discussed on page 77. If this 4.0% is too high then the market risk premium is not over-estimated to the same degree.
c) If the actual return was 5.8% and the income return 5.2% then investors earned an unexpected capital gains yield of 0.6% In this case the observed US market risk premium would only need to be reduced by 0.6% instead of 1.8%. However, conceptually you can not compare cash income yields with realised returns.

INTERROGATORY #12

Ref: Appendix A, page 10

Preamble: Dr. Booth lists the companies in whose cases he or he and Dr. Berkowitz appeared as expert witnesses.

Interrogatory

Please provide a table showing:

a) the recommended returns on equity and capital structure in each case in which Dr. Booth has appeared since 2000.

b) the date of the testimony.

c) the client on whose behalf the testimony was prepared.

d) the regulatory jurisdiction.

e) the date of the decision.

f) the awarded returns on equity and capital structures – if the case resulted in a settlement, please so indicate.

Please provide copies of all testimonies and accompanying schedules for each of the proceedings listed in the table.

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a)-f). Dr. Booth does not track the information requested. Prior to 2004, any evidence was filed on behalf of Berkowitz and Associates, and Dr. Booth's records from that period are incomplete. We will collect the evidence he has filed with the OEB and, where it is available, the AEUB. We will provide copies of that evidence as soon as it is collected. The decisions of the regulators are available from them. Those decisions will indicate how the regulators dealt with Dr. Booth's evidence..

INTERROGATORY #13

Ref: Appendix E, page 5

Preamble: Dr. Booth states that prior to the early 1950's, interest rates were controlled to stimulate the economy.

Interrogatory

a) Which interest rates is Dr. Booth referring to, what period is he referring to, and how were those interest rates controlled?

Dr. Booth is simply referring to the fact that war-time controls were imposed on interest rates as is clear from his Schedule E2 and the discussion of the efforts of the Bank of Canada to develop a Canadian money market in the reforms of 1953-4 discussed on pages E5. For added historic reference please see "The Corporate Short-term paper market," Bank of Canada Review September 1976. Also "the Bank of Canada in 1953 and 1954: a further stage in the evolution of central banking in Canada, Bank of Canada Review, June 1976. This paper is attached.

INTERROGATORY #14

Ref: Page 3

Preamble: Dr. Booth references the social cost of capital.

Interrogatory

a) Please define social cost of capital and explain in detail how it differs from the private cost of capital.

b) Please explain in detail how Dr. Booth would go about estimating the discount rate that he would use to evaluate new investments in regulated generating assets.

c) Please quantify the difference between the cost of capital Dr. Booth recommends for the prescribed assets and the cost of capital or discount rate Dr. Booth would expect OPG to use when evaluating investments in new regulated generation.

d) To the extent that the social cost of capital includes externalities such as environmental considerations, would he expect that investor-owned utilities should take such externalities into account when evaluating new projects? If no, please explain why not.

e) Does Dr. Booth know whether other regulated companies use discount rates that differ from their approved return to evaluate new regulated projects?

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a)The Social Cost of Capital is the appropriate discount rate to evaluate investments undertaken in the public sector. It differs from the private cost of capital in several areas. The most important are:

- Taxes, are they a cost or a wealth transfer?
- Risk, can the state diversify risk better than the equity markets?
- Time horizon: should the state consider the "generations yet unborn" since the capital markets don't?
- Externalities not considered by private firms:
    - Should the state consider spill-over benefits to other firms?
    - Are there costs that are imposed on others, such as FX and interest rate effects?

The social cost of capital is a significant topic in public finance, Ken Arrow won his Noble prize partly for a discussion of the SCC. An introductory textbook would be D. Quirin and J. Wigginton, <u>Analyzing capital expenditures: private and public perspectives,</u> Irwin, 1981.

b)and c) This would be a major exercise that Dr. Booth could not undertake as an IR response. Clearly the social risk imposed by OPG's nuclear plants is not the same risk that OPG is absorbing and asking to be compensated for. Consequently the cost of capital for evaluating new nuclear plants is considerably higher. The fact that the old Ontario Hydro imposed stranded debt costs on the ratepayers of this province of over $20 billion and the Province has limited OPG's freedom of action through the MOU indicates it is a significant risk.

d) The historic record is that private firms have not generally taken these liabilities into account in their capital expenditure decisions until regulated to do so. The environmental problems caused by mining operations, the existence of contaminated sites, leeching of pollutants into the water supply etc are only a few examples of significant problems where costs were not properly allocated in corporate investment decisions.

e) Dr. Booth is not privy to the internal corporate decision making of regulated utilities, and if he was, he is sure that such work would be confidential in nature. Further, it seems doubtful that the risk differences between social and private risk for standard utilities are as large as they appear to be for OPG's nuclear plants.

INTERROGATORY #15

Ref: Page 49

Preamble: Dr. Booth states that AltaLink has only capital deferral accounts, and therefore faces somewhat higher capital expenditure forecasting risk for a portion of its capital projects.

Interrogatory

Please explain in more detail how the capital expenditure forecasting risk differs between the typical gas pipeline and AltaLink.

This was Dr. Booth's summary of the ***AEUB's*** assessment of Altalink, note the introduction at the top of page 49. However, the concern at the time was that AltaLink did not have control over the capital expenditures for the Alberta transmission grid where bids were put out to tender.

INTERROGATORY #16

Ref: Page 51

Preamble: Dr. Booth refers to the risk transfer from generation to distribution in Alberta.

Interrogatory

a) Please confirm that the risk transfer related to the “legislated hedges”.

b) Please explain how the legislated hedges worked.

c) Please explain whether there is an analogue in the Ontario circumstances.

d) Please confirm that the allowed common equity ratio of the distribution function, due to the transfer of risk, was 56%.

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a) Yes.
b) What follows is a description of how the Alberta market was organised circa 1994.
c) The basic objective is the same which is to preserve the low cost power from historic generation while introducing competition.
d) Dr. Booth is not aware of this and would need verification.

Electric Utilities Act A Milestone For Alberta's Electric Industry

In the fall of 1993, the Alberta Minister of Energy, directed the Alberta Department of Energy to work with stakeholders to develop a new structure for Alberta's electric industry following two broad goals:
- Establish a mechanism that is fair from a province-wide perspective.
- Introduce industry structure and regulatory reforms that preserve and enhance the Alberta advantage of competitive electricity prices.

The Electric Utilities Act is the result of this work. It reflects a broad consensus among utilities, customers, independent power producers and regulators on how best to meet the Government's objectives. When the Act came into effect on January 1, 1996 it represented a turning point in the evolution of Alberta's electric industry. Over the coming months and years, Alberta will make the transition to a fully competitive market for power, and to more streamlined regulation in parts of business where customers are best protected by regulating costs.

The New Structure
The new structure does not affect the physical nature of electricity delivery, nor does it require integrated utilities to divest themselves of assets. However, the functions of generation, transmission and distribution will be treated separately for accounting, regulatory and functional purposes.

Open competition for generation: The new structure increases the number of players in the generation sector. Under the old arrangements, independent generators had to negotiate with the existing utility generators to sell power. Independent power producers and importers will now compete on an equal basis with existing utility generation, in both the current market to supply power and in the market to supply new generating capacity.

Open access power pool: A new provincial power pool is the market for all electricity bought and sold in the province. The pool is operated as a cooperative venture and is overseen by a council made up of representatives from all Alberta participants in the pool. All generators in Alberta and importers sell energy through the pool to distributors and exporters. The pool establishes an hourly market price for exchanges of power.

System access to the pool: All generators and importers are able to supply power on a non-discriminatory basis to the pool, regardless of who owns any given portion of the power lines. The grid that delivers electricity throughout Alberta is coordinated by a Transmission Administrator, who contracts with the owners of facilities to provide transmission services. The Transmission Administrator also ensures that necessary levels of system support services are in place. The Grid Company of Alberta Inc. (GridCo) has been appointed to fill this role in 1996. Tariffs to recover system access costs from distributors and generators are established by the Transmission Administrator, subject to regulatory approval.

Regulated distribution: Utilities will continue to have the basic right and obligation to meet the power supply requirements for all customers in their service areas. Service area boundaries are unchanged. To serve their customers, distribution companies will purchase energy through the pool and obtain transmission services from the Transmission Administrator. Distributors pay 'postage-stamp' rates for transmission: that is, all distributors pay the same price for transmission, regardless of how far they are from sources of generation.

Import and export: The new structure removes restrictions on who may import or export power in Alberta. Importers and exporters must become members of the Pool. They must also demonstrate that they have appropriate contractual arrangements with the Transmission Administrator and any external transmission systems involved in their transaction. Both importers and exporters will pay location-based tariffs for system access.

Impact on Customer Rates Implementing the Electric Utilities Act has almost no immediate impact on customer rates, since the costs of transmission and existing generation continue to be shared among all customers in the province. A great deal of work went into the regulation on how the costs of existing units are shared, to make sure that each distribution utility's costs are not significantly different in the near-term than they would have been under the former system

The effect of new pricing arrangements made by distribution utilities on behalf of their customers will be averaged across the province, as has been the case in the past. Since new generation is expected to be more expensive than existing generation, this means that rate differences could appear if distributors' loads grow at different rates.

However, future differences in rates are forecast to be minimal. This is because load growth rates are not expected to differ significantly and system access rates will be the same for all distributors.

Depending on the outcome of the study of customer price choice, it is also possible that consumers will be able to make their own pricing arrangements for new generation.

In the long term, increased competition and incentive regulation are expected to result in lower costs than the old structure would have provided.

The Power Pool
The power pool is an open-access, competitive market for electric energy. The Electric Utilities Act stipulates that all electricity traded in the province will be bought and sold through the pool.

Key concepts underlying the pool include:
- Anyone wishing to participate in the pool must become a member of the pool.
- The pool accepts energy offers from all generators and importers belonging to the pool. This includes existing generators as well as plants that are built in the future.
- The pool also accepts bids for energy from distributors for price-sensitive load; i.e., load that would prefer to be curtailed rather than pay more than a given price for power.
- The pool acts as an hourly spot market for energy. A single price is declared for each hour based on a weighted average of the prices of the most expensive units dispatched (or demand bids curtailed) to meet load in that hour.
- All energy is traded at the declared pool price for the hour. There is no spread between the price paid by buyers and that received by sellers.
- The pool does not take part in arranging, settling or managing bilateral contractual agreements between buyers and sellers of power. This does not preclude such contacts. It is expected that buyers and sellers will find it advantageous to have bilateral pricing agreements, and that they will use the pool price to settle imbalances.

Management of the Pool
Three entities play a role in managing the power pool: the Power Pool Council, the Power Pool Administrator and the system controller.

Power Pool Council: The council is responsible for making sure the pool operates as an open, fair and efficient market for power. The Power Pool Council is an independent corporation make up of representatives from consumer groups, independent power producers, utilities, and other organizations with a stake in the pool. The council is responsible for establishing the rules by which the pool operates, and for appointing the Pool Administrator and system controller.

Power Pool Administrator: The Power Pool Administrator is responsible for carrying out the financial transactions and general operations of the pool. This includes:
- Managing the bid-offer process, in which participants submit their prices for supplying to and receiving power from the pool.
- Determining the "merit order" (the ranking of units according to the price they offer into the pool) and working out the overall schedule for which units should run when.
- Scheduling units to provide system services, such as operating reserve.
- Carrying out all the financial settlements, so that distributors pay for the power they purchase and generators receive their payment.
- Determining the costs of running the pool and recovering these costs through membership fees charged to pool participants.

System Controller: The system controller is responsible for the task of keeping a large, dynamic electric system physically stable. This is a minute-by-minute, hour-by-hour job as load rises and falls, as generating units come onto the system. as emergencies arise with transmission facilities or generators. Specific tasks include:
- Dispatching units and price-responsive demand bids according to the schedule set by the Power Pool Administrator.
- Coordinating with owners of transmission facilities.
- Communicating system services requirements to the Power Pool Administrator and making sure the system has adequate levels in place at all times.

Importing and exporting power: All power imported into and exported from Alberta is also traded through the power pool. Importers submit offers to sell to the pool, are placed in the merit order with other suppliers of energy and receive the pool price for energy sold to the pool. Exporters submit bids to buy from the pool and pay the hourly pool price for energy taken. The Power Pool Administrator must ensure that scheduled flows across the transmission lines linking Alberta to other systems are feasible. Importers and exporters must belong to the Power Pool and must demonstrate that they have in place the necessary arrangements with any external transmission systems they use.

Generation
All generators must sell their energy through the power pool.

In the early years of the new structure, most of the energy sold through the pool will come from Alberta's existing generating units, which continue to be owned by the utilities. However, as electric load grows and existing units are retired, future generation will be built through competition among suppliers.

Existing units offer energy to the pool in the same way as any supplier does, and receive the pool price for the energy they sell. However, the Electric Utilities Act treats existing generation differently from other supply in one important way: by ensuring that the costs of these units continue to be shared by all customers in the province.

This was an important objective in shaping the new structure since Alberta, unlike many other jurisdictions, has a low average cost for existing generation. The new structure ensures that Albertans continue to share this advantage, regardless of where they are located in the province.

The mechanism for achieving this objective is a set of legislated financial "hedges" between distributors and owners of existing generating units. The specifics of the hedges are determined through a combination of regulations and EUB decisions. Essentially, they ensure that the price distributors pay for power from existing units is close to the variable cost of generating that power. In return, distributors are required by the EUB to contribute fixed monthly payments to cover the fixed costs of existing generation.

This mechanism ensures that:
- Distributors (and therefore their customers) are hedged against pool prices which are greater than the cost of power from existing sources for their current load requirements.
- Utilities are not faced with the risk of stranded investment for generating facilities they have built.

The legislated financial hedges are shared equitably among distributors on the basis of their shares of total provincial load.

New Generation
Any generator can build new generating capacity in Alberta. Two kinds of companies will compete to build generation in the future:
- Independent power producers, such as industrial customers with their own generation, cogenerators (who simultaneously produce power and heat for some other purpose) and owners of renewable energy sources.

- The generating arm of existing utilities. Any contract between a generator and its affiliated distribution company will be reviewed by the Alberta Energy and Utilities Board. The regulator is responsible for making sure any such contract is negotiated fairly and independently, and is in the best interest of customers.

In Alberta's new industry structure, there is no longer a requirement for the regulator to approve new generating units on the basis of province-wide need for capacity. Instead, market forces will come into play as distributors forecast the pool price and make appropriate financial arrangements with new generators in order to hedge the hourly pool price. Alternatively, a generator may build a new unit on the basis of forecast revenue at the pool price.

Transmission
The province-wide transmission will be managed as a single entity, although transmission facilities will continue to be owned by the respective utilities. This recognizes that transmission must be operated as an integrated system to maintain reliability and cost efficiencies. Two bodies play key roles in managing the transmission system: the Transmission Administrator and the Electric Transmission Council.

Transmission Administrator: The Transmission Administrator is responsible under the Act for the overall coordination of the transmission system.

The role of the Transmission Administrator will is currently filled by the Grid Company of Alberta Inc. GridCo was established through a shareholders' agreement among the four utilities in the province that own transmission facilities.

Distributors purchase system access, and pay for it according to the province-wide tariff established by the Transmission Administrator. In this way, all consumers pay a common, postage-stamp cost for transmission no matter where they are located in the province.

Rates for existing generators reflect their contribution to the cost of system services, as well as costs that are common to all suppliers of power into the pool. Contribution to power system services could be either a credit or a charge. Rates for new generators to connect into the system will cover site-specific connection costs plus location sensitive costs that reflect the transmission benefits or burdens associated with their location. Location-based rates should encourage the efficient location of new plants on the grid.

Electric Transmission Council: The Electric Transmission Council is made up of distributors, generators, independent power producers, consumer groups and rural electrification associations, as well as representatives from the transmission owners. It is responsible for reviewing the activities of the Transmission Administrator and advising on issues related to the grid.

System Access and Tariffs
Transmission costs continue to be regulated. The Transmission Admin-istrator submits a tariff schedule to the Alberta Energy and Utilities Board for approval. Several key principles underlie system access rates:

Postage-stamp rates to distributors: This ensures all customers face a system access tariff that is independent of where they are located in the province.

Location-based rates for generators: The structure of the rate paid by generators for access to the system encourages them to locate where they will minimize transmission costs for the system as a whole.

Costs include system support services: A transmission system depends not only on power lines and transformers to deliver power. It must deliver power at stable voltages, and requires such support services as "spinning reserve" and automatic generation control to maintain the system within narrow tolerances as load rises and falls. A transmission system also loses a certain amount of power in delivery across long distances. The costs of such items are included in the costs recovered through system access rates.

Import and export rates: Importers and exporters pay a fixed system access fee for all contracts to offset the costs of administering them. A "transmission transfer charge" ($/MWh) is posted daily by the Transmission Administrator for service on the following day. The minimum transfer charge is $2/MWh, but is otherwise based on available market indices and should vary to reflect demand for transmission capacity.

Distribution
In Alberta's new industry structure, distributors continue to have essentially the same relationship with their customers as before. Service area boundaries are unaffected by the Act.

However, behind the scenes, distributors play a different role than in the former, vertically integrated system. They put the components of delivering power together in a different way.

The six largest distribution systems in the province are each obligated to pay a share of the fixed costs of Alberta's existing generating units. In return, they are entitled to a legislated financial hedge of the energy produced by those units. The hedge is related to the regulated operating costs of the units (if pool price is higher than the regulated cost, distributors pay the lower, regulated cost for energy).

These distribution utilities have a number of responsibilities (and risks) that stem from their legislated hedges:
- They must arrange with the Transmission Administrator for system access services.
- They must settle with the pool for all energy taken.
- As load grows and the legislated hedges come to cover less of their needs, they must be prepared either to remain unhedged, purchasing the difference at the pool price, or to enter into new price hedging arrangements with suppliers.

Other Distribution Agents
Besides the six "entitled" distribution utilities, there are a number of other distributors in the province. These include smaller municipalities that own their own distribution systems and rural electrification associations (REAs). All the municipalities buy their energy and system access services from TransAlta. The REAs have contracts either with TransAlta or Alberta Power.

These distributors buy energy from entitled utilities, and the costs they pay reflect their share of overall load in the province. Essentially, their share of the hedges is built into TransAlta's or Alberta Power's entitlement.

These distributors have the option of participating directly in the power pool and making their own arrangements for future capacity if they wish to do so. In this case, the costs (both fixed and variable) related to their share of existing generation would be transferred from Alberta Power or TransAlta to the smaller system, which would then take on all the risks and responsibilities associated with the entitlement.

Cost regulation

While competition will control the cost of new generation, regulation is still needed in many areas of the electric industry. Existing generating units continue to be regulated to ensure that customers retain the benefits of their low cost. The operation of the transmission system will be monitored to ensure that no conflict of interest occurs among generators, distributors and transmission owners who are linked corporately. Distribution costs and the allocation of those costs across customer classes will be reviewed. Regulation continues to protect consumers in all areas of the industry.

The Alberta Energy and Utilities Board is responsible for examining and approving the following:
- The cost of existing generation owned by Alberta Power, TransAlta Utilities and Edmonton Power, until such time as a negotiated agreement is reached to replace a unit's legislated financial hedge or a unit is removed from regulation under terms to be set by regulators under the Act.
- Replacement of the legislated financial hedges with negotiated hedges.

- System access tariffs submitted by the Transmission Administrator, based on the costs submitted to the administrator by transmission owners. The costs incurred by investor-owned distribution companies, along with the retail rates they charge to customers. The distribution costs and rates for municipally owned utilities are regulated by their respective municipalities rather than the Board.
- Any new, long-term financial arrangements that distributors enter into with generators to hedge the pool price.

The EUB will continue to review applications to build generating plants for compliance with environmental and siting requirements.

Incentive regulation

Regulation of Alberta's electric utilities, as in most other jurisdictions, has been based on the traditional "cost of service" approach. With this approach, regulators review all areas of a utility's expenditures and determine whether the costs have been prudently incurred and can be charged back to customers. As part of the exercise, the regulator determines a reasonable rate of return on the investment in facilities; this is what constitutes a utility's earnings.

Incentive regulation (also known as "performance-based' regulation) aims to reduce costs by giving utilities stronger incentives to pursue efficiencies. Traditional cost of service regulation does not reward exploration of new or different ways to increase efficiency. The key to incentive regulation is to allow utilities to keep part of any profits gained from innovative cost reductions. This increases their incentive to search for ways to cut costs.

There are several ways to implement incentive regulation. Approaches that are being tried in other parts of North America include:
- Setting measures that reward generating units for meeting certain performance targets.
- Increasing the period over which rates are approved, which gives utilities a stronger incentive to forecast their costs accurately, and to meet or exceed performance forecasts.
- Setting price caps that keep consumers rates below certain targets.

Looking ahead

The implementation of the Electric Utilities Act this year represented a milestone in the development of Alberta's electric industry - but certainly not an end point. In the months and years ahead, Alberta's electric industry will continue to evolve towards a fully competitive generation market.

For more information contact the Alberta Department of Energy, Tel: (403) 427-8177 and ask for a copy of "Moving to Competition: A Guide to Alberta's new electric industry structure.

INTERROGATORY #17

Ref: Page 87

Preamble: Dr. Booth estimates the market risk premium at 5.0%, compared to 4.5% in his 2003 evidence in the combined Enbridge/Union proceeding.

Interrogatory

Please explain in detail the reasons for increasing the market risk premium from 4.5% to 5.0%.

This is discussed in detail in Dr. Booth's Appendix E.

INTERROGATORY #18

Ref: Page 55

Preamble: "The fact that OPG has asked for so many deferral accounts on such minutia indicates to me that the risk has been reduced to at or below the level of most standard utilities. As often happens for Canadian utilities, the risk of OPG's operations is not borne by the shareholder, but by the ratepayer."

Interrogatory

Identify the "standard utilities".

This can be taken to mean any Canadian utility other than PNG. Of course OPG is not a standard utility since it has no obligation to serve and is not a monopoly in the generation of electricity.

INTERROGATORY #19

Ref: Page 49

Preamble: Dr. Booth references the EUB's business risk categories.

Interrogatory

Please indicate if the conclusions regarding relative risk are those of the EUB or of Dr. Booth. If the former, please indicate where the EUB compared the supply risks of gas pipelines to those of electricity generation.

These are Dr. Booth's paraphrasing of the EUB's decision, which runs to many pages. Dr. Booth did not say that the AEUB considered electricity generation in fact he specifically stated (page 49)

> "Here it should be pointed out that the AEUB did not consider generating plants in its business risk assessment.

In terms of supply risk for natural gas pipelines the AEUB stated (page 37)

> "The Board agrees with the interveners that NGTL has a higher short-term business risk than the electric transmission companies, principally due to higher competition and credit risks. The Board also considers that NGTL potentially faces higher long-term risks due to supply risk although, in the Board's view, the bulk of that risk, if it materializes, will likely be identified early enough for NGTL to apply to the Board for potential adjustments to throughput forecasts and/or depreciation rates. "

INTERROGATORY #20

Ref: Page 5-6

Preamble: [T]he cost of capital is the **minimum** rate of return required by investors in a firm. The fair return is then this minimum plus a financial flexibility allowance. The cost of capital then ignores the return requirement of non-investors since they have not invested in the firm and implicitly have a higher required rate of return: by definition if they had a lower rate of return they would have valued the assets more highly and invested in it! The fact that the province remains the sole owner and is unwilling to sell off the assets is a critical fact and indicates that these assets are more valuable to the province than to other investors. This fact cannot be ignored."

Interrogatory

What is the basis in finance theory for the claim that "The cost of capital then ignores the return requirement of non-investors…"?

By definition the cost of capital is the required rate of return for investors in the firm. Many people do not own shares or shares in a particular firm, as a result their return expectations are not captured in market prices and do not affect the cost of capital. This is a basic result in finance flowing from the standard discounted cash flow model. I may want a 50% return for investing in TransCanada Corporation, for example, but if I am not the marginal investor who cares?

INTERROGATORY #21

Ref: Page 31, lines 23-31

Preamble: "[M]ost private companies have an asset base that consists largely of intangible assets. For example, the major value of Nortel was its growth opportunities; of Coca Cola its brand name; of Merck its R&D team. It is extremely difficult for non-regulated firms to borrow against these assets. Growth opportunities have a habit of being competed away; brand names can waste away, while R&D teams have a habit of moving to a competitor. Regulated utilities in contrast largely produce un-branded services and derive most of their value from tangible assets. Unlike intangible assets, tangible assets are useful as collateral, for example in first mortgage bonds, and are easy to borrow against."

Interrogatory

What is the empirical basis for the claim that most private companies have asset bases made up largely of intangible assets?

We can see this from two facts:

- The market to book ratios of "growth stocks" where the intangible is their growth expectations. This in finance is referred to as PVGO, the present value of growth opportunities;
- The second is the asset composition of firms where intangible assets such as goodwill appear on their balance sheets as "other assets." This asset reflects the value of brand names, growth options trade names, patents etc, where the value can-not be allocated to hard tangible assets after an acquisition.

INTERROGATORY #22

Ref: Page 5, lines 23-24 and 26-28

Preamble: "First, the standalone principal (sic) simply asserts that there should not be any subsidies in the operation of the utility…. However, it does not mean that ratepayers should be charged a phantom "risk premium" as if the utility was owned by a third party."

Interrogatory

What is the basis for the conclusion that the stand alone principle "simply" asserts that there should not be any subsidies? What legal research and/or judicial opinions has Dr. Booth relied on in arriving at that conclusion?

Dr. Booth is not a legal expert and has done no research on legal precedent. His statement is based on economic theory and why we regulate firms using rate base ROE regulation and often require "arms-length" contracts between a utility holding company and the regulated subsidiary.

INTERROGATORY #23

Ref: Appendix G, schedule 7

Interrogatory

Please provide the underlying data used to calculate the interest coverage ratios.

Data is as follows (to expand grab the handles):

GAS UTILITIES 55102010

Average of stock price index, December 30, 1994 = 100

INCOME ACCOUNT	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
OPERATING INCOME BEFORE DEPRECIATION & AMORTIZATION	35.38	41.80	43.59	42.43	49.14	50.73	63.57	37.28	33.13	29.24	30.37	25.61	25.01	26.44
DEPRECIATION & AMORTIZATION	16.83	16.59	16.17	14.25	19.27	22.07	22.10	17.53	13.59	11.66	10.87	10.12	10.30	10.53
OPERATING INCOME AFTER DEPRECIATION (OIAD)	18.55	25.20	27.41	28.17	29.86	28.66	41.46	19.74	19.53	17.58	19.50	16.11	15.49	14.94
INTEREST EXPENSES	6.47	8.34	10.51	9.12	14.94	17.83	15.88	8.24	6.71	6.66	6.25	9.55	5.25	5.96
SPECIAL ITEMS	-2.25	-6.30	1.37	-1.51	-0.13	-0.16	1.56	-2.05	-4.03	-3.18	0.79	1.64	-0.42	0.38
MINORITY INTEREST (INCOME STATEMENT)	0.00	0.00	0.42	0.80	1.23	1.82	1.45	0.50	0.62	0.60	0.45	0.28	0.15	0.08
PRETAX INCOME	11.70	14.07	20.94	22.41	20.68	19.08	31.66	12.37	10.07	10.57	16.02	8.82	10.68	10.00
INCOME TAXES	3.36	3.54	6.89	6.54	5.85	7.08	11.00	3.82	2.68	2.99	5.50	3.05	3.10	3.61
EXTRAORDINARY ITEMS AND DISCONTINUED OPERATIONS	0.73	0.34	-0.92	-3.24	0.03	-0.02	-0.63	-1.28	-0.05	-0.39	-0.03	4.12	0.27	0.63
NET INCOME	9.07	10.87	12.70	11.82	13.62	10.14	18.54	6.65	6.69	6.57	10.03	9.64	7.65	7.16
PREFERRED DIVIDENDS	0.00	0.05	0.13	0.13	0.14	0.26	0.87	0.38	0.28	0.20	0.23	0.27	0.33	0.38
COMMON DIVIDENDS	0.44	0.00	0.00	0.00	0.00	0.00	0.27	1.81	3.29	2.94	2.61	2.36	2.18	1.99
ASSETS														
CASH EQUIVALENT	3.07	11.25	15.11	7.97	6.23	13.21	16.79	12.73	5.42	3.93	4.01	3.69	8.40	7.95
RECEIVABLES	28.18	80.99	28.63	23.64	25.23	68.43	104.09	38.00	30.22	32.75	32.51	22.41	18.13	19.89
INVENTORIES	8.92	36.50	20.70	10.53	7.79	14.24	11.88	7.13	7.37	5.20	5.46	5.45	6.52	6.24
OTHER CURRENT ASSETS	21.52	50.98	34.15	53.79	52.93	51.64	127.19	36.22	22.04	20.67	15.25	11.91	12.64	9.36
TOTAL CURRENT ASSETS	61.70	179.73	98.60	95.94	92.19	147.54	259.96	94.10	65.07	62.56	57.24	43.48	45.71	43.44
NET PROPERTY PLANTAND & EQUIPMENT	197.68	296.75	274.61	259.63	237.12	349.97	400.37	283.61	173.15	173.95	169.41	163.00	150.28	147.67
OTHER ASSETS	30.10	67.85	134.27	116.18	124.36	173.37	186.44	78.77	78.41	64.29	42.80	39.42	38.38	37.97
TOTAL ASSETS	287.77	523.71	505.34	471.23	453.29	670.27	846.29	464.28	316.38	300.62	269.31	245.90	234.38	229.09
LIABILITIES & SHAREHOLDERS' EQUITY														
DEBT IN CURRENT LIABILITIES	17.17	52.31	42.92	24.80	38.44	59.44	90.94	34.71	14.53	13.61	11.89	9.94	11.39	7.87
ACCOUNTS PAYABLE	28.41	69.22	30.91	16.82	19.28	62.27	93.85	33.73	24.18	25.96	28.19	18.63	15.52	20.35
INCOME TAXES PAYABLE	1.09	4.02	5.05	2.48	2.94	2.50	3.25	3.45	1.85	2.11	2.48	4.47	2.59	2.61
OTHER CURRENT LIABILITIES	19.53	48.58	38.04	60.43	62.22	67.03	138.41	36.45	31.57	22.75	18.38	16.12	15.97	16.75
TOTAL CURRENT LIABILITIES	66.20	174.14	116.94	104.55	122.89	191.26	326.46	108.36	72.14	64.44	60.96	49.17	45.48	47.61
LONG TERM DEBT	52.88	88.86	142.94	136.53	137.83	202.90	223.31	117.95	86.18	81.45	71.37	66.46	59.42	57.26
DEFERRED TAXES AND INVESTMENT TAX CREDIT	36.65	58.66	53.07	48.09	50.16	68.62	77.65	42.50	29.51	29.98	31.55	30.15	25.15	0.91
MINORITY INTEREST (BALANCE SHEET)	0.00	0.00	0.18	10.18	8.59	25.58	21.70	12.29	13.77	10.15	5.97	4.18	2.76	1.84
OTHER LIABILITIES	45.93	98.26	65.02	63.92	35.69	51.37	60.22	33.65	27.25	27.53	22.59	23.40	36.85	36.17
PREFERRED STOCK	0.00	0.00	1.35	2.30	2.70	2.38	3.76	1.85	1.66	2.03	3.62	5.89	4.60	4.93
COMMON STOCK	20.78	33.66	6.81	20.96	17.71	25.81	27.69	32.57	33.81	30.63	11.08	12.04	11.81	11.24
CAPITAL SURPLUS	0.75	0.50	99.72	60.25	57.82	64.89	81.72	36.43	12.48	14.34	29.68	27.41	28.25	27.99
RETAINED EARNINGS	64.72	70.02	36.81	33.39	30.12	54.75	47.36	56.98	40.77	41.78	32.91	28.08	21.81	17.30
LESS TREASURY COST	0.15	0.42	4.90	5.63	6.42	6.82	8.69	3.60	1.23	1.74	0.47	0.91	1.79	0.00
TOTAL LIABILITIES	287.77	523.71	505.34	471.23	453.29	670.27	846.29	464.28	316.38	300.62	269.31	245.90	234.38	229.09
FINANCIAL RATIO														
TOTAL DEBT TO TOTAL CAPITAL (%)	50.40	73.28	65.73	65.10	73.51	76.27	83.76	63.12	57.98	56.41	56.18	54.97	57.06	54.86
TOTAL DEBT TO TOTAL EQUITY (%)	81.36	136.04	134.24	148.06	177.61	189.23	212.22	125.07	117.33	111.83	113.73	114.67	117.88	115.21
TOTAL DEBT TO EBITDA (%)	198.04	337.74	426.36	380.19	358.67	517.08	494.31	409.52	303.98	325.02	274.11	298.28	283.10	246.34
FREE CASH FLOW TO TOTAL DEBT (%)	-8.33	0.00	0.00	0.00	0.00	0.00	-3.45	-23.57	-27.83	-24.54	-14.42	-19.15	-13.56	-13.71
RETURN ON TOTAL ASSETS	2.90	1.99	2.67	3.16	2.96	1.47	2.16	1.63	2.04	2.24	3.65	2.13	3.00	2.68
BOOK VALUE RETURN	9.59	10.14	9.84	13.82	13.69	7.33	12.96	6.57	7.85	8.19	13.75	8.28	12.29	11.55

ELECTRIC UTILITIES 55101010

Average of stock price index, December 30, 1994 = 100

INCOME ACCOUNT	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
OPERATING INCOME BEFORE DEPRECIATION & AMORTIZATION	39.75	37.33	35.17	34.51	32.56	36.83	32.34	34.37	35.01	33.77	33.11	33.08	30.52	29.88
DEPRECIATION & AMORTIZATION	13.19	13.69	12.71	12.15	12.47	12.68	14.52	12.92	13.00	12.17	10.80	10.14	9.70	9.22
OPERATING INCOME AFTER DEPRECIATION (OIAD)	26.56	23.64	22.45	22.36	20.09	24.15	17.89	21.66	22.00	21.60	22.30	22.94	20.82	20.66
INTEREST EXPENSES	7.89	7.91	8.43	9.93	10.45	11.06	11.01	9.15	8.21	7.65	7.14	7.08	7.10	7.49
SPECIAL ITEMS	-1.74	-1.77	1.48	-2.14	0.36	-0.21	0.26	1.52	-0.37	-1.21	-0.30	-0.66	0.00	-0.83
MINORITY INTEREST (INCOME STATEMENT)	0.19	0.01	-0.11	-0.06	0.08	0.35	0.32	0.26	0.15	0.06	0.05	0.03	0.01	0.00
PRETAX INCOME	19.00	15.61	16.71	11.75	11.27	14.59	8.90	15.33	14.10	13.21	15.52	15.78	14.39	13.81
INCOME TAXES	6.21	4.80	5.10	3.44	3.50	4.63	2.94	5.15	5.05	4.93	5.77	5.76	5.19	5.05
EXTRAORDINARY ITEMS AND DISCONTINUED OPERATIONS	0.26	-0.32	-0.70	-1.11	-5.07	-0.97	-0.05	-0.54	-0.75	-1.77	0.04	0.50	0.00	0.21
NET INCOME	12.86	10.45	10.63	7.48	2.48	10.57	5.59	9.37	8.12	6.45	9.73	10.48	9.16	8.97
PREFERRED DIVIDENDS	0.16	0.12	0.11	0.14	0.18	0.19	0.20	0.25	0.33	0.58	0.67	0.81	0.78	0.81
COMMON DIVIDENDS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASSETS														
CASH EQUIVALENT	8.20	6.64	8.97	9.77	12.47	12.75	9.55	10.60	6.82	5.60	2.90	3.12	2.22	3.11
RECEIVABLES	11.48	13.86	14.78	15.42	17.73	22.84	27.76	16.97	14.84	14.00	9.24	8.61	7.48	7.61
INVENTORIES	8.31	7.43	7.18	7.38	7.41	7.51	5.98	6.22	5.44	5.17	5.52	5.67	5.91	5.96
OTHER CURRENT ASSETS	15.87	19.74	11.21	12.78	13.60	20.79	36.97	8.78	8.84	6.08	4.87	5.75	5.10	5.21
TOTAL CURRENT ASSETS	43.85	47.69	42.16	45.36	51.23	63.89	80.27	42.59	35.96	30.87	22.54	23.16	20.71	21.90
NET PROPERTY PLANTAND & EQUIPMENT	226.57	213.80	220.98	216.28	198.19	215.81	202.73	194.69	178.00	191.22	195.84	195.66	192.73	193.83
OTHER ASSETS	103.95	100.38	97.71	101.94	105.07	118.45	109.21	101.39	88.34	67.20	55.02	50.95	48.07	48.45
TOTAL ASSETS	374.38	361.88	368.72	363.59	354.49	398.42	391.93	338.41	302.08	289.07	273.42	269.79	261.52	264.20
LIABILITIES & SHAREHOLDERS' EQUITY														
DEBT IN CURRENT LIABILITIES	16.44	17.89	14.48	15.29	36.17	32.68	40.65	29.08	21.02	14.87	12.45	10.87	9.77	9.60
ACCOUNTS PAYABLE	11.08	13.36	13.98	12.84	15.24	18.22	25.05	12.34	10.47	9.93	7.06	6.42	5.94	6.17
INCOME TAXES PAYABLE	3.99	3.73	3.14	3.22	2.80	2.38	2.60	4.39	2.84	2.73	2.64	2.56	2.35	2.55
OTHER CURRENT LIABILITIES	19.81	22.37	16.40	17.96	17.84	28.34	39.60	14.74	13.26	11.86	8.13	9.33	7.93	9.18
TOTAL CURRENT LIABILITIES	51.31	57.36	48.01	49.33	72.07	81.64	107.91	60.57	47.60	39.41	30.29	29.19	26.00	27.51
LONG TERM DEBT	109.94	106.12	107.90	125.45	121.08	140.41	121.11	118.46	100.49	95.73	84.07	83.33	82.82	84.88
DEFERRED TAXES AND INVESTMENT TAX CREDIT	45.75	43.24	40.87	40.08	39.20	39.84	42.55	45.17	45.72	48.26	51.06	50.52	49.03	0.00
MINORITY INTEREST (BALANCE SHEET)	0.40	0.46	0.49	0.70	0.97	3.97	3.23	2.00	1.16	0.68	0.79	0.77	0.53	0.43
OTHER LIABILITIES	66.65	61.29	60.11	64.74	42.69	43.73	33.43	28.27	22.22	18.55	15.02	14.12	13.12	11.45
PREFERRED STOCK	2.96	2.50	1.96	2.29	2.99	2.76	3.60	3.74	4.49	5.90	8.97	11.11	11.50	11.60
COMMON STOCK	28.76	26.58	27.78	29.20	36.77	33.56	32.34	32.40	33.25	34.19	32.52	32.35	33.42	31.25
CAPITAL SURPLUS	29.79	32.49	34.04	34.42	24.41	24.69	24.05	22.23	19.62	17.93	18.13	17.54	17.01	18.97
RETAINED EARNINGS	42.81	35.95	33.47	19.61	17.20	29.18	27.44	29.98	28.61	29.39	33.45	31.49	28.49	27.82
LESS TREASURY COST	3.99	4.16	3.27	2.26	2.93	2.58	3.76	3.75	0.73	0.24	0.54	0.30	0.26	0.21
TOTAL LIABILITIES	374.38	361.88	368.72	363.59	354.49	398.42	391.93	338.41	302.08	289.07	273.42	269.79	261.52	264.20

INTERROGATORY #24

Ref: Page 60, line 16 to page 61, line 5

Preamble: "The Bruce Power restart is now projected to cost $3.1-3.4 billion and assuming a further 10% escalation in costs Mr. Hal Kvisle projects a 10% unlevered after tax return. This after tax return must be below the discount rate or fair return that TransCanada and its partners are using, otherwise they would not be continuing with the project. This would correctly put the fair return for the Bruce Power start up at the top of the discounts rates used by RBC-DS for more conventional power plants. Given that OPG's prescribed nuclear assets have more regulatory protection this would place the fair return at significantly less than this 10% unlevered equity cost."

Interrogatory

a) What is the empirical basis for your conclusion that 10% must be above the cost of equity target of TransCanada and its partners?

b) Does Dr. Booth agree that the return on equity target for the original lease contract would be based primarily on operating risk, not restart and refurbishment risk?

c) Does Dr. Booth believe that operating risk for Bruce Power is materially different from that of OPG? If so, please explain the reasons for this belief and provide the empirical basis for assessing the impact of operating risk on Bruce Power's capital structure and return on equity and explain how this would impact an assessment of appropriate capital structure and return on equity for OPG.

---

a) Investors do not invest unless the expected rate of return exceeds their required rate of return. Otherwise they are throwing money aware by undertaking negative NPV projects. This is a basic proposition in financial theory and assumes that TransCanada is a well run firm.
b) No. Dr Booth would assume that the lease holders would anticipate the future refurbishment. The following excerpts from Hansard (June 6, 2002) indicate that the lease-holders took this into account in pricing the lease and whether it was good value for the province.

Second, with respect to whether the appropriate value was received by OPG and the shareholder for leasing the Bruce facility, we assessed and compared the present value of the future cash flows from the lease and from the status quo—"status quo" meaning if OPG continued to operate the Bruce facility. We calculated that, under the lease, the present value of OPG's cash flows would be about $170 million less than under the status quo. However, we concluded that this amount is highly volatile, because changes in the assumptions made to determine the difference in value between the lease and the status quo could dramatically change this amount. Specifically, changes in the assumptions relating to the following key factors can have a significant impact:

(1) future electricity prices;

(2) the number of years the reactors can operate without major refurbishment;

(3) the level of ongoing capital and operating costs; and

(4) the amount of electricity production lost due to maintenance downtime.

c) Dr. Booth offers no opinion on Bruce Power other than that contained in TransCanada's news release that indicates a maximum 10% unlevered equity cost.

INTERROGATORY #25

Ref: Page 5, lines 17-19

Preamble: Dr. Booth indicates that we cannot ignore the actual owners of the utility.

Interrogatory

Please provide Dr. Booth's estimates of the equity ratios (nuclear, hydro and total) that would be required for a privately-owned utility with the same regulated assets as OPG and the same proposed deferral/variance accounts and payment structure.

This is impossible to answer without considering the reaction of the Province and the terms under which the assets are leased or sold. Further the issue before the Board is the fair rate of return of the existing assets under the current arrangements, not a hypothetical situation and any possible answer is irrelevant.

INTERROGATORY #26

Interrogatory

In Dr. Booth's opinion, could the regulated nuclear facilities at Pickering and Darlington be financed on a stand alone basis? If so, how much equity investment would be required? On what basis has Dr. Booth come to this conclusion? Has he had in depth discussions with providers of debt and equity capital to power generators with respect to the reasonableness of his recommendations regarding the ROE and capital structure for OPG's nuclear assets?

Since Bruce Power was leased it is feasible that the OPG nuclear assets could be leased, but it is doubtful that this could happen without the Province backstopping any agreement in a material way. Again such a situation is hypothetical and not relevant to the issues before the Board, where the people of this province either as tax payers or ratepayers continue to bear the risks attached to these assets. As long as this continues, it is in the public interest to preserve the low cost power these assets generate. To charge ratepayers higher costs on the basis of a mythical risk that the owners bear, when the ratepayers are essentially the owners, does not make sound economic policy.